BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-87:
2025 Tri-State 2023 ERP 120 Day Implementation Report

Colorado PUC E-Filings System

Tri-State Generation and Transmission Association, Inc.

2023 Electric Resource Plan

Phase II Implementation Report

PUBLIC VERSION

(Colorado Public Utilities Commission Proceeding No. 23A-0585E)

NOTICE OF CONFIDENTIALITY

A portion of this document has been filed under seal.

Confidential Information has been redacted in the following documents.

- Report Pages 26, 27, 37, 38, 48, 49, 59, 69, 70, 80, 81
- Attachment B

Highly Confidential Information has been redacted in the following documents:

- Attachments B, B-4, B-7, B-8, C, C-1, D-1, D-2, D-3, D-4, D-5, D-6, F-1, F-2, F-3, G

April 11, 2025

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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 Utility Member Systems located across Colorado, Nebraska, New Mexico, and Wyoming.

This report is Tri-State's 2023 Electric Resource Plan (ERP) Phase II Implementation Report. The report complies with applicable Colorado Public Utilities Commission (CoPUC) Rules and Decisions as identified in Attachment A.

Tri-State's preferred portfolio is Portfolio 4 – New ERA Gas Flexibility Shafer Replacement (FLEXSR). The FLEXSR portfolio adds 700 MW of wind and solar, 650 MW of storage, and 307 MW of gas between 2026-2031, replaces the turbines at J.M. Shafer to improve its capacity contributions,[1] maintains the previously announced Craig 3 and SPV 3 retirement dates, and results in a generation portfolio that meets both Level 1 and Level 2 Reliability Metrics, the Colorado GHG emissions reduction targets,[2] the Colorado Renewable Energy Standard, and the New Mexico Renewable Portfolio Standard, all while avoiding costly transmission upgrades identified in other portfolios—making FLEXSR the least-cost portfolio.[3] This portfolio, which selects 1,657 MW of new resources from the 2024 Requests for Proposals (RFPs), reflects Tri-State Members' strategic directive to ensure reliable, affordable, and responsible service, and also addresses the CoPUC's recent concerns "…regarding the large, unexpected cost increases in transmission investments…" and a "need to improve [ ] transmission modelling and cost estimation processes in future ERP proceedings…"[4] The CoPUC Commissioners have also identified their concern in recent public meetings, recognizing that generation selected through ERPs has been "agnostic" in terms of evaluating associated transmission expenses and indicating a desire to "…analyze and optimize…options to ensure that our generation selection…to ensure that we're looking at optimizing costs across the system including the transmission system…"[5] Tri-State's approach to bid selections in the FLEXSR portfolio directly addresses these concerns, as described in detail in Attachment G.

Tri-State has selected the FLEXSR portfolio as a result of the portfolio's overall performance across the reliability, environmental, and financial categories analyzed and described in this report. Tri-State has taken steps to initiate a Resource Solicitation Cluster (RSC) for entering FLEXSR bids into Tri-State's Generator Interconnection through its Open Access Transmission Tariff (OATT) Large Generator

[1] The Shafer replacement is described in Attachment H.

[2] 2020 ERP Phase I Settlement Agreement, at Section 3.3.4 (Proceeding No. 20A-0528E): "Tri-State agrees that, going forward, it will operate its system in a manner that achieves, at a minimum, with respect to its APCD-verified 2005 Baseline, the following reductions in GHG emissions related to Tri-State's wholesale sales of electricity in Colorado (the "Interim-Year Emissions Reductions"): A twenty-six percent (26%) reduction in calendar-year 2025; a thirty-six percent (36%) reduction in calendar-year 2026; and a forty-six percent (46%) reduction in calendar-year 2027."

[3] Lowest PVRR, exclusive of SCoC and SCoM.

[4] These concerns arose in other recent Phase II proceedings. *See* Decision No. C24-0052, at ¶ 158 in Proceeding No. 21A-0141E (issued January 23, 2024).

[5] CWM March 5, 2025, Commissioner Gilman at 1:12:31 and 1:12:53. Publicly available at: https://www.youtube.com/watch?v=dol_38ci5dU.

Interconnection Process. Four of the ten bids already have a queue position and therefore do not need to be part of the RSC study. The benefits of FLEXSR over other portfolios are reflected in the analyses presented in this Phase II report.

Portfolio Analysis Summary

Tri-State modeled six portfolios for Phase II of the 2023 ERP and created three back-up bid pools, as identified in Attachment B-3. All of the Phase II modeling reflected input assumptions based on the best available information available at the start of modeling, reflective of any known Tri-State system constraints and compliance requirements, as described in Attachment B and Attachments B-1 through B-8.

Tri-State remains in a capacity-long position until 2030;[6] however, resource acquisitions are required through this Phase II for ensuring ongoing resource adequacy and reliability as two coal units are retired in 2028 and 2031 and to maintain progress toward emission reductions for Colorado statutory compliance as well as for New ERA funding eligibility. Waiting to procure resources needed for 2030 until the 2027 ERP would not be prudent given that the 2027 ERP Phase II process may not conclude until late 2028 or early 2029; however, Tri-State is cautious to not pursue new resources based on speculative loads. At the same time, retirement of dispatchable coal resources cannot be affordably or reliably replaced solely with semi-dispatchable resources. The new resources, including the dispatchable gas plant in Moffat County, will provide jobs and tax base that support community vitality across many areas of our system.

Tri-State considered the Social Cost of Carbon (SCoC) and Social Cost of Methane (SCoM) when determining which Phase II portfolio was preferred, including analysis of the environmental and financial comparisons shown in the Comparative Analysis section of this report. Tri-State has taken these comparisons into significant account in determining that our preferred portfolio in Phase II is the best course of action at this time. Tri-State's preferred portfolio achieves the lowest present value of revenue requirements (PVRR), meeting the affordability expectations of Tri-State Members in avoiding the risks associated with procuring bids selected in other portfolios at a higher cost that do not yield impactful environmental or reliability attributes.

All of the Phase II portfolios meet essential reliability targets, while achieving an 80 percent GHG emissions reduction in Colorado in 2030 (with respect to the 2005 baseline)[7] reflective of Colorado policy.[8] However, the other portfolios analyzed result in significant, unnecessary financial burdens by aggressively pursuing resources with high transmission interconnection upgrade costs that are not necessary to achieve the same operational, environmental, and reliability benefits resulting from procurement of FLEXSR bids. Tri-State is keenly aware of the economic challenges its Members face in rural America. Demographic data indicates 59 percent of our service area is considered economically disadvantaged or distressed.[9] Tri-State is not in a position to pursue generation procurements that

[6] *See* Table 2, Loads and Resources, submitted in the 2024 ERP Annual Progress Report filed December 2,2024 in Proceeding No. 23A-0585E.
[7] See Attachment D.
[8] §25-7-105(1)(e)(VIII)(I), C.R.S.
[9] U.S.D.A.: https://ruraldevelopment.maps.arcgis.com/apps/webappviewer/index.html.

would cause significant undue financial burdens for Members[10] or compromise its ability to meet the core reliability expectations of its Members.

Additional details on the comparative analysis Tri-State completed to support its preferred portfolio selection can be found in the Comparative Analysis section of this report.

Addressing Commission Rule 3605(h)(II)

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

> *In accordance with §§ 40-2-123 and 40-2-124, C.R.S., the Commission shall consider renewable energy resources, resources that produce minimal emissions or minimal environmental impact, energy-efficient technologies, and resources that affect employment and long-term economic viability of Colorado communities. The Commission shall further consider resources that provide beneficial contributions to Colorado's energy security, economic prosperity, environmental protection, and insulation from fuel price increases.*

Phase II of Tri-State's 2023 ERP included RFPs for a diverse mix of renewable, storage, and dispatchable resources located across the Tri-State system. Bidders were required to provide Best Value Employment Metrics (BVEM) information identifying Colorado employment benefits.[11] The Phase II portfolio analysis reflected GHG Targets (2025, 2026, 2027, and 2030),[12] Energy Efficiency Targets (2024, 2025, and 2030),[13] and Demand Response Targets (2025 and 2030)[14] as agreed upon in the Settlement Agreements in Phase I of the 2020 and 2023 ERPs.

Colorado's energy security, economic prosperity, and insulation from fuel price increases are best supported by a Tri-State portfolio that is diverse in the type, size, location, and operations of generation, including through bid procurements that avoid costly transmission network upgrades. Tri-State developed, in consultation with stakeholders, a set of robust reliability criteria in 2022, updated reflective of a third-party 2024 EWE Study, and tested portfolios' extreme weather event (EWE) sensitivities to ensure future resource additions can meet the necessary reliability and resource adequacy needs of its Members. The FLEXSR preferred portfolio meets these rigorous standards, both affordably and responsibly.

The preferred portfolio will continue to advance the environmental objectives of the State of Colorado because it is forecasted to achieve the Colorado GHG Targets. The GHG reductions were calculated using the Colorado Air Pollution Control District's (APCD) emissions workbook methodology.

[10] Tri-State is subject to Federal Energy Regulatory Commission rate jurisdiction, as of September 3, 2019.
[11] *See* HIGHLY CONFIDENTIAL Attachment F-1.
[12] 2020 ERP Settlement Agreement, at Section 3.3.4. (Proceeding No. 20A-0528E).
[13] 2020 ERP Settlement Agreement, at Section 3.11.9. (Proceeding No. 20A-0528E).
[14] 2020 ERP Settlement Agreement, at Section 3.11.8. (Proceeding No. 20A-0528E); 2023 ERP Settlement Agreement, at Section 4.9.1. (Proceeding No. 23A-0585E).

In accordance with § 40-2-129, C.R.S., the Commission shall determine: whether the utility has provided best value employment metrics; whether the utility has certified compliance with the objective standards for the review of such best value employment metrics as set forth in the RFP approved in the Phase I decision; and whether the utility has agreed to use a project labor agreement for the construction or expansion of a generating facility.

Tri-State has provided BVEM provided by bidders, for the bids advanced to modeling, in HIGHLY CONFIDENTIAL Attachment F-1.

Tri-State included evaluation of BVEM as a non-price factor in its bid evaluation, as described in the Bid Evaluation section of this report.

Tri-State intends to enter into power purchase agreements (PPAs) and Engineering, Procurement, and Construction contracts (EPCs) for the preferred portfolio generation and storage facilities; therefore, the developers and EPC contractors will be responsible for determining whether a project labor agreement will be used.

In accordance with § 40-2-134, C.R.S., the Commission shall determine whether the final cost-effective resource plan meets the energy policy goals of Colorado.

The FLEXSR preferred portfolio is the most cost-effective portfolio modeled, having the lowest PVRR. The preferred portfolio also complies with all applicable rules and regulations in the state of Colorado, including achieving at least an 80 percent reduction in GHG emissions by 2030 while continuing to ensure affordable and reliable service.

In accordance with § 40-3.2-106(3), C.R.S., the Commission shall consider the net present value of the cost of carbon dioxide emissions, the net present value of revenue requirements of the cost-effective resource plan, and other relevant factors as determined by the Commission in its Phase I decision.

The FLEXSR preferred portfolio has the lowest PVRR among the portfolios modeled, including analysis for optimization of interconnection cost as described in Attachment G. Tri-State considered the SCoC in its review of the portfolio modeling results as described in the Portfolio Analysis Summary section above and in the Comparative Analysis section below.

Stakeholder Engagement

Tri-State has engaged transparently and collaboratively in stakeholder engagement throughout the 2023 ERP. Numerous stakeholder groups representing a diverse set of interests participated in meetings in advance of Tri-State's filing of this Implementation Report. These discussions provided an opportunity to further educate stakeholders on the complexities of the Tri-State system, inform parties of key modeling inputs and assumptions, and facilitate dialogue on topics applicable to Phase II. These stakeholder meetings occurred between December 2023 and March 2025, covering the following topics:

1. November 29, 2023: Briefing on 2023 ERP Phase I Filing

2. January 24, 2024: EWE Focus Group[15] Meeting #1
3. March 1, 2024: EWE Focus Group Meeting #2
4. March 21, 2024: EWE Focus Group Meeting #3
5. April 23, 2024: 2024 DSM Roundtable Meeting (1 of 2)
6. June 11, 2024: FERC Filing Updates
7. September 24, 2024: Meeting on USDA Guidance and Phase II Portfolios[16]
8. October 30, 2024: Meeting on EWE[17]
9. December 10, 2024: 2024 DSM Roundtable Meeting (2 of 2)
10. December 23, 2024: Colorado PUC Staff Meeting on MIP[18]

Several e-mail communications and updates to stakeholders also occurred in advance of and during Phase II modeling with the aim of ensuring communications on key Phase II topics. Tri-State maintains ongoing collaboration with interested stakeholders across a variety of electric sector topics.

Bid Evaluation

Tri-State issued three Phase II RFPs on September 13, 2024. Tri-State's bid evaluation process was undertaken over a 45-day period following the close of the RFPs on October 28, 2024.[19] The bid evaluation process, completed prior to advancing projects to Phase II computer-based modeling, consisted of several steps – including a completeness screen, an economic screen, an interconnection/transmission screen, and a non-price factor screen.

The ***completeness review*** included an assessment of whether bids provided required information, such as fully completed bid forms or other narrative requirements. This screen also ensured submittal of the required bid fee(s). When bid information appeared incomplete or unclear, Tri-State contacted the bidders and provided them approximately two business days to supplement their bids with the necessary information to enable the bids to move forward in the bid evaluation process.

Following the completeness review, bids were sorted by technology type (wind, solar, etc.) and passed through an ***economic screen***. Either a levelized cost of energy (LCoE) or leveled cost of capacity (LCoC) was evaluated, depending on the technology type, as identified in the table below.

Table 1: Economic Screen by Technology Group Applied to Phase II Bids

LCoE	LCoC
Solar	Standalone Battery
Wind	Dispatchable Combustion Turbine
Solar + Battery	Dispatchable Natural Gas with CCS
Wind + Battery	
Geothermal	

[15] EWE Focus Group included Tri-State, Tri-State's Wyoming Members, Grid Lab, Sierra Club and their consultants, and Rocky Mountain Institute (RMI).
[16] 2023 ERP Settlement Agreement, at Section 4.4.3 (Proceeding No. 23A-0585E).
[17] 2023 ERP Settlement Agreement, at Section 4.8.3 (Proceeding No. 23A-0585E).
[18] 2023 ERP Settlement Agreement, at Section 4.4.8 (Proceeding No. 23A-0585E).
[19] The dispatchable RFP bid deadline was extended to November 27, 2024 due to the limited number of bids received.

Bids in each technology group, in various size ranges, were advanced to the transmission and interconnection screen if the costs were at or below the latest generic resource pricing and/or where other size, locational, or diversity considerations were applied.

The ***interconnection/transmission screen*** included a review of project/facility sizes (capacity), point of interconnection (POI), transmission provider, and queue status and transmission/interconnection provider verification. Bidders were expected to clearly identify projected interconnection and transmission costs in their proposals as well as reflect these costs in the prices associated with each bid. Tri-State's Transmission Planning team reviewed each bid's viability and the reasonableness of associated cost estimates. The viability screen focused on the ability of the transmission system to accommodate the new firm resource and the ability to construct the project, including network upgrades and interconnection facilities by the identified in-service date. Cost estimates were reviewed to ensure bids factored in a reasonable level of network upgrade and interconnection facility costs to integrate the project at the identified point of interconnection. Finally, Tri-State's Transmission Planning team verified whether the project was in an interconnection queue based on the information provided by the bidder. For projects achieving commercial operation in 2026 or 2027, bidders were required to be in an interconnection queue under a transmission provider's generator interconnection process. For those projects whose commercial operation dates (COD) were anticipated to be after 2027, bidders were encouraged to be in an interconnection queue, however, this will not be a requirement in the interconnection/transmission screen.

For projects under a PPA structure, interconnection with the Tri-State transmission system was viewed more favorably than those projects connecting to a third-party transmission system. For projects in which Tri-State was seeking ownership, interconnection with the Tri-State transmission system was required. The interconnection/transmission provider was noted as part of the interconnection/transmission screen.

Projects that did not receive favorable evaluation results during the interconnection/transmission screen were eliminated from further consideration in the bid evaluation process. In cases where the interconnection/transmission screen identified certain flawed aspects of an otherwise viable bid, related primarily to cost and/or in service date assumptions, Tri-State contacted bidders for clarification and cost updates.

Lastly, Tri-State conducted a ***non-price factor analysis*** of the bids that emerged from the interconnection and transmission screen. The non-price factor analysis considered project capabilities across four categories: community stewardship, counterparty profile, project feasibility, and project capability. The factors are identified in the table below.

Table 2: Non-Price Factors

Category	Factor
Community Stewardship	• Best Value Employment Metrics • Contribution to meeting GHG reductions in Colorado • Location in a Tri-State Member System • Location in Moffat County or West End of Montrose County • Community Benefits
Counterparty Profile	• Bidder's prior experience with project development

	• Bidder's record of litigation related to power supply agreements and failure to honor bids from prior solicitations, or failure to complete projects as proposed • Financial viability of the bidder • Markup of PPA or term sheet terms and conditions
Project Feasibility	• Certainty of financing and outside funding sources to include tax credits or government subsidies/incentives • Compliance with all applicable local, state and federal laws, rules and orders, and processes; permit(s) identification and status • Local opposition or community efforts to stop project development • Ability to source materials • Project retirement/decommissioning plan • Legal, engineering and other costs required to implement the proposed project
Project Capability	• Renewal and purchase options at end of PPA (if applicable) • Impact on scheduling project output to Tri-State load • Operational flexibility

Projects with overall favorable non-price factor analysis were advanced to modeling; however, poor evaluation results in certain non-price factor categories resulted in a project not being advanced to modeling.

Bids Received

Tri-State received 145 individual eligible bid proposals by the bid deadline, as identified in the 45-Day Report filed in Proceeding No. 23A-0585E on December 12, 2024. A total of 52 bids were advanced to modeling, as shown in HIGHLY CONFIDENTIAL Attachment C, following the bid evaluation described above. On December 5, 2024, Tri-State notified bidders whether their projects had advanced to modeling and offered a price refresh opportunity per Tri-State's Bid Policy,[20] due December 9, 2024. For bids not advanced to computer-based modeling, and for which bidders requested additional feedback on their bids, Tri-State identified at which stage of the bid evaluation process the bid failed to pass a screen and offered an opportunity for further discussion at or near the conclusion of Phase II. Tri-State also provided details in its 45-Day Report[21] identifying how many bids failed to pass each screen and factors that caused bids to fail at each screen.

Table 3: Summary of Bids Advanced to Modeling by Technology Type

Technology Type	Total (# of Bids)	MW	MW BESS
Solar	12	2,303	-
Wind	6	1,218	-
Solar+Battery	12	2,049	907
Wind+Battery	1	180	100
Short-Duration Storage	16	-	2,200

[20] Hearing Exhibit 102 Attachment SKH-7 (Proceeding No. 23A-0585E).

[21] https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=1032592&p_session_id=

Long-Duration Storage	1	-	100
Gas Plant	2	495	-
Gas Tolling	1	314	-
Geothermal	1	20	-
TOTAL	**52**	**6,579**	**3,307**

Commission Rule 3605(h)(I)(A)(iii) requires that Tri-State "provide the Commission with the best value employment metrics information provided by bidders." The BVEM information provided by bidders whose bids were advanced to modeling is provided in Attachment F-1. As identified in Table 2 above, BVEM is a non-price factor analyzed by Tri-State as an element of bids' community stewardship.

Tri-State is also providing to the Commission and stakeholders a mapping of the bid project locations overlayed with a map of disproportionately impacted (DI) communities, in Highly Confidential Attachment C-1.[22] The file contains five maps: 1) all bids with DI overlay, 2) bids advanced to modeling with DI overlay, 3) bids selected in portfolio modeling with DI overlay, 4) bids selected in the preferred portfolio with DI overlay, and 5) bids selected in the preferred portfolio with Tri-State Member territories overlay.

Bids Selected in Portfolio Modeling

Table 4 identifies the bids selected in one or more of the portfolios modeled.

Table 4: Bids Selected in Portfolio Modeling

Bid	Technology Type	MW	Portfolios					
			1 – NEE	2 – NELG	3 – FLEX	4 – FLEXSR	5 – NNG	6 – NNGSR
PV-0004-4-nm	Solar	100	☒	☒	☒		☒	
PV-0004-5-wco	Solar	140	☒	☒			☒	
PV-0006-8-eco	Solar	200				☒		☒
WI-0013-2-wyo-wne	Wind	200	☒	☒	☒	☒	☒	☒
WI-0013-3-eco	Wind	200	☒	☒		☒	☒	☒
WI-0016-1-eco	Wind	297			☒			
PC-0009-2P-eco	Solar / Battery	150 / 75	☒	☒	☒		☒	
PC-0018-1P-nm	Solar / Battery	100 / 50	☒	☒	☒	☒	☒	☒
ST-0002-5-wco	4hr - Battery	50	☒	☒	☒	☒	☒	☒
ST-0002-6-wco	4hr - Battery	100		☒				
ST-0004-10-eco	4hr - Battery	100		☒		☒	☒	☒
ST-0004-6-eco	4hr - Battery	150				☒		☒
ST-0004-8-wco	4hr - Battery	200					☒	☒
ST-0004-9-eco	4hr - Battery	100					☒	☒
ST-0009-3-wco	4hr - Battery	200	☒	☒	☒	☒	☒	☒
ST-0009-4-nm	4hr - Battery	100	☒	☒	☒	☒	☒	☒
ST-0010-4-eco	4hr - Battery	150			☒		☒	☒
ST-0017-1-eco	4hr - Battery	100	☒	☒	☒		☒	☒
ST-0018-1-eco	4hr - Battery	50			☒		☒	
ST-0019-1-eco	Iron Air Battery	100	☒				☒	

[22] 2023 ERP Settlement Agreement, at Section 4.10.2. (Proceeding No. 23A-0585E).

GG-0006-1-wco	Combustion Turbine	307		☒				
GG-0006-2-wco	Combustion Turbine[23]	307	☒		☒	☒		

Independent Evaluator

Tri-State utilized the services of a third-party Independent Evaluator (IE) to support RFP administration, and to validate the bid evaluation process and results. The role of the IE was to ensure fairness, transparency, and consistency in Tri-State treatment of bids.

In order to provide the bidder a paperless (electronic only) experience and prior to the Phase II RFP release, the IE assisted Tri-State with web hosting, website development, and web-form development to provide a standardized bidder experience by hosting the following services: RFP website and bidder registration, notice of intent and non-disclosure agreements process support, and bidder document upload and storage management. Tri-State created an Outlook mailbox for each RFP that the IE could also access, enabling the IE to view communications with bidders, to monitor for consistency and transparency.

The IE reviewed the non-price factor evaluation criteria matrix prepared by Tri-State and confirmed its fairness and consistency and alignment to the Bid Policy. After Tri-State completed each bid evaluation screening phase, Tri-State prepared a summary of the results that included the purpose of the screen, the evaluation criteria, and the bid advancement results; then Tri-State and the IE discussed the results. The IE independently reviewed a subset of bids that passed and failed each screen to validate and ensure consistency across bid evaluation results. The IE communicated its completion of each screening review.

Due to only a very limited number of bids being received on October 28, 2024, in response to the Dispatchable RFP, Tri-State consulted with the IE for concurrence in issuing a 30-day extension for the Dispatchable RFP to November 27, 2024. Tri-State informed the 2023 ERP Settling Parties of the Dispatchable RFP extension via email. Beginning November 28, 2024, Tri-State and the IE completed an accelerated screening of dispatchable bids to remain on track with the 45-day bid evaluation period.

The IE uses and is familiar with EnCompass, the same modeling software used by Tri-State. Tri-State shared its model with the IE for review of Tri-State's modeling inputs and set-up, primarily for ensuring bid data was consistent with bidder-provided information. After Phase II portfolio modeling, the IE also reviewed modeling outputs for any anomalies.

The IE is expected to file a report providing its observations of Tri-State's Phase II process simultaneous to the filing of this report.

Phase II Portfolio Analysis

Tri-State modeled six portfolios:

1. New ERA Expanded (NEE)
2. New ERA Limited Gas (NELG)

[23] Eight 38.36 MW natural gas-fired turbines, hydrogen-capable with a demonstrated blend of 30%.

3. New ERA Gas Flexibility (FLEX)
4. FLEX Shafer Replacement (FLEXSR)
5. No New Gas (NNG)
6. NNG Shafer Replacement (NNGSR)

The modeling assumptions unique to each portfolio are identified in Attachment B-3.

Tri-State also conducted expansion plan modeling to identify three back-up bid pools:

7. Renewable Back-up Bid Pool (BkRE)
8. Standalone Storage Back-up Bid Pool (BkST)
9. Gas Plant Back-up Bid Pool (BkNG)

Tri-State will, to the extent necessary, utilize backup bid pools to replace preferred plan bids that fail. If a preferred plan bid cannot move forward, Tri-State aims to replace it with a similarly sized, similar technology type project, if possible, subject to limitations and economics. This designation of bids as back-ups is limited to creation of a potential pool of the next most economic bids, as Tri-State cannot anticipate which preferred plan bid or subset of bids could fail at a given point in time; therefore, modeling unknown and possible portfolio permutations would be inefficient. The bids identified in the back-up pools are not listed in an anticipated order of preference; this is because selection from the back-up pools depends upon which preferred plan bid would happen to fail and what location of the Tri-State system that bid was located and the transmission constraints projected at the bid locations at the time of CODs. Tri-State would, upon any bid failure(s), utilize bid(s)[24] from the relevant back-up bid pool along with the remaining preferred portfolio of bids still viable, and run a dispatch at that time to ensure continued adherence to the same affordability, reliability, and responsibility metrics and principles each Phase II portfolio was measured against. Tri-State will timely notify the Commission of any bid failures, identify steps taken to remediate the failed project, where feasible, and identify the back-up bid, or combination of backup bids, selected from the pools.

Additionally, a sensitivity analysis was performed to re-dispatch each portfolio under EWE conditions. The modeling assumptions and results of the sensitivity analyses are provided separately in Attachment E.[25]

Each section of this report that follows presents data and analytical results from base portfolio modeling, formatted in the following order:

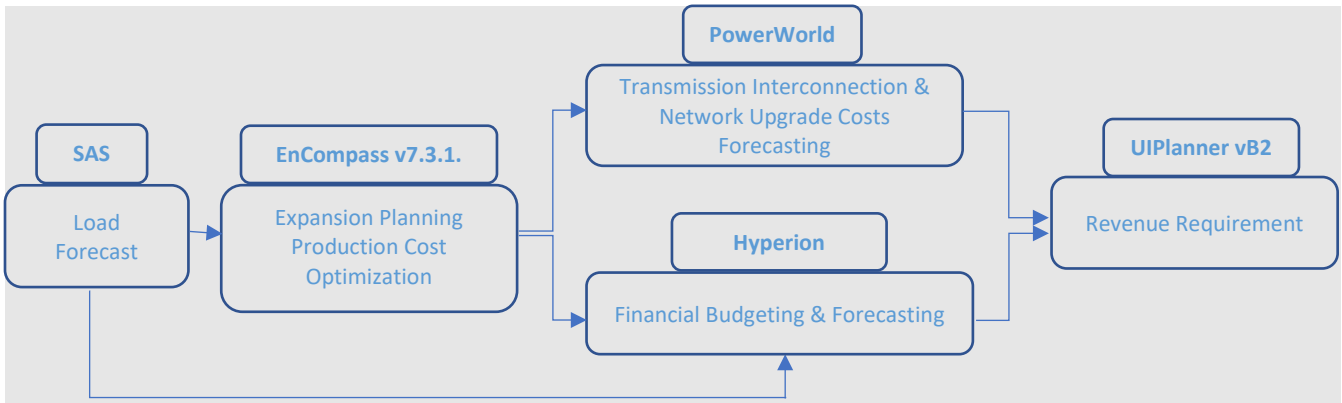
- Expansion Plan, Retirements, System Mix, and Capacity Factors
- Environmental Analysis
- Financial Analysis
- Transmission Analysis
- Reliability Analysis

An overview of Tri-State's approach to each element of the portfolio analyses is provided below.

[24] One bid, depending on the unit size, may need to be replaced by one or more bids.
[25] 2023 ERP Settlement Agreement at Section 4.8.1. (Proceeding No. 23A-0585E).

Figure 1 below identifies the software tools utilized by Tri-State for completing each component of the portfolio analyses and the succession of data flow through each modeling and analytical system. Use of the EnCompass modeling software for capacity expansion and portfolio optimization began in 2022.

Figure 1: Modeling Software Tools



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 II modeling, inputting the applicable modeling assumptions described in Attachment B and Attachments B-1 through B-8, as applicable. Resource bids advanced to modeling as a result of the RFPs issued by Tri-State on September 13, 2024 and selected in the portfolio expansion plans are identified by a bid identifier, resource type, and project megawatts (MW).

The RAP for Phase II is 2026-2031, with the full Resource Planning Period (RPP) modeled for 2024-2043.[26]

Environmental Analyses

Based on the expansion plan and dispatch produced for each portfolio, Tri-State has provided an analysis of forecasted system-wide emissions and water use, as well as the annual social costs of carbon and methane.

For each portfolio, Tri-State separately produced a verification workbook, using the Colorado Air Pollution Control Division's (APCD) latest template,[27] calculating forecasted carbon emissions reductions, provided in Attachment D files. Target-year emissions reductions percentages for each portfolio, calculated within the verification workbooks, are provided in this report.

Financial Analyses

Pursuant to Rule 3605(h)(I)(A)(ii), Tri-State provided a financial analysis of each portfolio and each Tri-State owned resource, including:

- Annual revenue requirements;

[26] Tri-State's Hyperion financial forecasting for 2024 consists of six months of actuals and six months of forecast. Tri-State's financial forecasting for 2025 reflects Tri-State's Budget rather than EnCompass 2023 ERP Phase II dispatch output due to timing of the modeling, however, neither year is part of the Resource Acquisition Period (RAP).

[27] *See* Attachment B.

- Present value revenue requirement, with and without the social costs of carbon and methane; and
- A net present value of each owned resource, over the planning period, with and without the social costs of carbon and methane.

Additionally, 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.[28] For each portfolio, curtailment MWhs by intermittent resource type seasonally and year are provided.

Transmission Analyses

Bidder-provided transmission cost estimates for proposed generation projects submitted in response to Tri-State's RFP were analyzed as part of the bid evaluation process to identify bids that should be advanced to portfolio modeling. Each portfolio was analyzed for its impact on transmission expenditures – both forecasted interconnection costs and additional network upgrades anticipated to be required, beyond already planned upgrades.

In addition to the traditional transmission interconnection and upgrades estimates prepared for each portfolio, Tri-State evaluated preferred portfolio bid selection in a manner that optimized interconnection costs, given growing transmission system constraints in recent years. As Tri-State was completing 2023 ERP Phase II portfolio modeling, it became increasingly clear that the EnCompass model was effectively selecting least-cost bids based on their operational profiles and the Tri-State system needs and transmission constraints, but the expansion plan model did not have full insight into the downstream transmission interconnection and network upgrade costs that were resulting from the bid selections. Additionally, the model could not identify opportunities where use of surplus interconnection could maximize the value of existing interconnections.[29] Tri-State was able to complete interconnection optimization for two of the portfolios—the preferred portfolio (FLEXSR) and the NNGSR portfolio. Optimizing the preferred portfolio enabled the avoidance of approximately $370M in transmission capital expenditures inclusive of allowance for funds used during construction (AFUDC) during the RAP. Optimizing the NNGSR portfolio enabled the avoidance of approximately $317M in transmission capital expenditures including AFUDC during the RAP.

Transmission planning cannot at this time be fully integrated into the generation planning process due to regulatory jurisdiction and organized market considerations, unique transmission and generation planning compliance requirements, bid timeline constraints, and variations in key modeling input cycles. However, Tri-State was able to address interconnection optimization in this Phase II by separately evaluating transmission cost and locational aspects of the bids following expansion plan selection. Going forward, Tri-State will integrate this optimization step across all portfolios beginning in Phase II of

[28] 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 minimum and must take contracts (*i.e.,* hydropower and Basin contracts)–in that order.

[29] A recent report from GridLab suggests "PUCs should require evaluation of surplus interconnection options in integrated resource planning (IRP)," See *Existing Power Plants Sharing Grid Access with Renewables Can Lower Costs and Double U.S. Generation Capacity*, at page 4, released in February 2025: https://surplusinterconnection.s3.us-east-1.amazonaws.com/2025-02-21_GridLab_Surplus_Interconnection_Technical_Paper.pdf.

the 2027 ERP, to continue to enable the avoidance of interconnection and upgrade expenses and optimize use of the existing transmission system. Tri-State will work with its EnCompass software provider, and the IE, to identify potential approaches to informing the model of bid interconnection costs and transmission upgrade costs within the expansion plan selections, and will describe any proposed modeling changes in its Phase I filing for the 2027 ERP.

Reliability Analyses

Level 1 reliability metric checks were performed on each portfolio for all years of the RPP,[30] 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 (%).[31]
    - Target (min) is 22% transitioning to 30.5% in 2028 after the retirement of the Craig facility
- *Loss of Load Hours (LoLH)*[32]: 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)[33]
        - 2024-2031 – annually cannot exceed 2.4 hours[34]
        - 2032-2043 – cannot exceed 24 hours over entire period
- *Expected Unserved Energy (EUE)*[35]: 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[36]

Evaluation of Level 2 Reliability Metrics, identified in Attachment B-5, was performed on each portfolio's EWE dispatch for all years of the RPP,[37] with results reflected in Attachment E.

Comparative Analysis

Tri-State compared and analyzed results across portfolios, which can be found in the Comparative Analysis section of this report.

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[30] 2023 ERP Settlement Agreement, at Section 4.8.2. (Proceeding No. 23A-0585E).

[31] *Reserve Margin and Effective Load Carrying Capability (ELCC) Study,* Astrape Consulting, publicly available here: https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=1011579&p_session_id=

[32] LoLH is equivalent to Loss of Load Probability (LoLP) terminology used in Tri-State's 2023 ERP Phase I.

[33] 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.

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

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

[36] This metric is aimed at limiting EUE to a reasonable level below the historical annual average, consistent with the 2023 ERP Phase I.

[37] 2023 ERP Settlement Agreement, at Section 4.8.2. (Proceeding No. 23A-0585E).

State Renewable Policy Compliance Analysis

Tri-State reviewed the results of each portfolio and affirms that all portfolios 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 5: Colorado RES and New Mexico RPS Requirements during RPP

	Colorado RES[38, 39]		New Mexico RPS[40]
	Co-ops	**Tri-State**	**Co-ops**
2024	10%	20%	10%
2025-2029	10%	20%	40%
2030-2050	10%	20%	50%

[38] § 40-2-124(1)(c)(I)(D) and (c)(V)(D), C.R.S.
[39] § 40-2-124(8)(b), C.R.S.
[40] N.M. Stat. Ann. § 62-15-34.

1. New ERA Expanded (NEE)

Assumptions unique to the New ERA Expanded (NEE) portfolio are identified in Attachment B-3.

Portfolio 1 (NEE) – Expansion Plan, Retirements, System Mix, and Capacity Factors

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

Table 6: Expansion Plan (Portfolio 1 – NEE)

Year	Bid Project	Technology	Planning Region	Unit Size (MW)	Number of Units[41]	Total MW
2026	ST-0002-5-wco	4hr - Battery	West Colorado	50	1	50
2027	PV-0004-5-wco	Solar	West Colorado	140	1	140
2028	ST-0019-1-eco	Iron Air Battery	East Colorado	100	1	100
	PC-0018-1P-nm	Solar / Battery	New Mexico	100	1	100
	ST-0009-4-nm	4hr - Battery	New Mexico	100	1	100
2029	WI-0013-3-eco	Wind	East Colorado	200	1	200
	GG-0006-2-wco	Combustion Turbine	West Colorado	38.36	8	307
	PV-0004-4-nm	Solar	New Mexico	100	1	100
	ST-0017-1-eco	4hr - Battery	East Colorado	100	1	100
2030	PC-0009-2P-eco	Solar / Battery	East Colorado	150	1	150
	ST-0009-3-wco	4hr - Battery	West Colorado	200	1	200
	WI-0013-2-wyo-wne	Wind	Wyoming / W.Neb	200	1	200
2033	-	Wind / Battery	New Mexico	100	2	200
2035	-	Geothermal Storage	West Colorado	20	1	20
2036	-	Wind / Battery	New Mexico	100	1	100
	-	10hr - Battery	East Colorado	100	1	100
2037	-	Wind / Battery	Wyoming / W.Neb	100	1	100
2038	-	Wind / Battery	East Colorado	100	2	200
2041	-	Solar	New Mexico	100	1	100
2042	-	Solar	New Mexico	100	1	100
	-	Wind	East Colorado	100	3	300
2043	-	10hr - Battery	East Colorado	100	1	100
	-	Wind	East Colorado	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:

- All plans include applicable Colorado energy efficiency targets in base assumptions.
- 2025: Low New Mexico Energy Efficiency was selected in the expansion plan of Portfolio 1 – NEE.
- 2030: Low Wyoming Energy Efficiency was selected in the expansion plan of Portfolio 1 – NEE.

[41] Each bid is modeled as a single project for purposes of expansion plan selection.

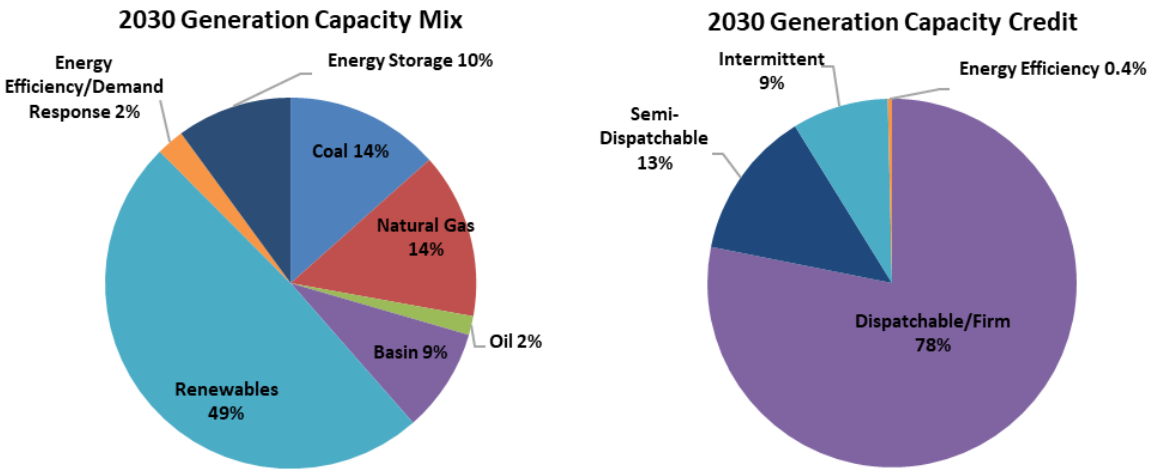
Unit retirements, scheduled or selected in the modeling, are shown in the following table.[42]

Table 7: Modeled Retirements (Portfolio 1 - NEE)

Location	MW	Technology	Date
Craig 1	427	Coal	12/31/2025
Craig 3	448	Coal	1/1/2028
Craig 2	410	Coal	9/30/2028
Springerville 3	418	Coal	3/1/2031[43]

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

Figure 2: Projected Tri-State System Capacity Mix 2030 (Portfolio 1 – NEE)[44, 45]



[42] 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). Tri-State's share of Craig 1 is 102 MW and its share of Craig 2 is 98 MW. Craig 3 is modeled to retire on the date selected and approved in Phase I of the 2023 ERP.

[43] The New ERA award requires a March 1, 2031 retirement date for SPV 3, given the requirement by USDA to disperse all New ERA funds by September 30, 2031.

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

[45] Rounding of percentages may lead to values displayed that do not appear to total to 100 percent exactly.

Figure 3: Projected Tri-State System Energy Mix 2030 (Portfolio 1 – NEE)[46]

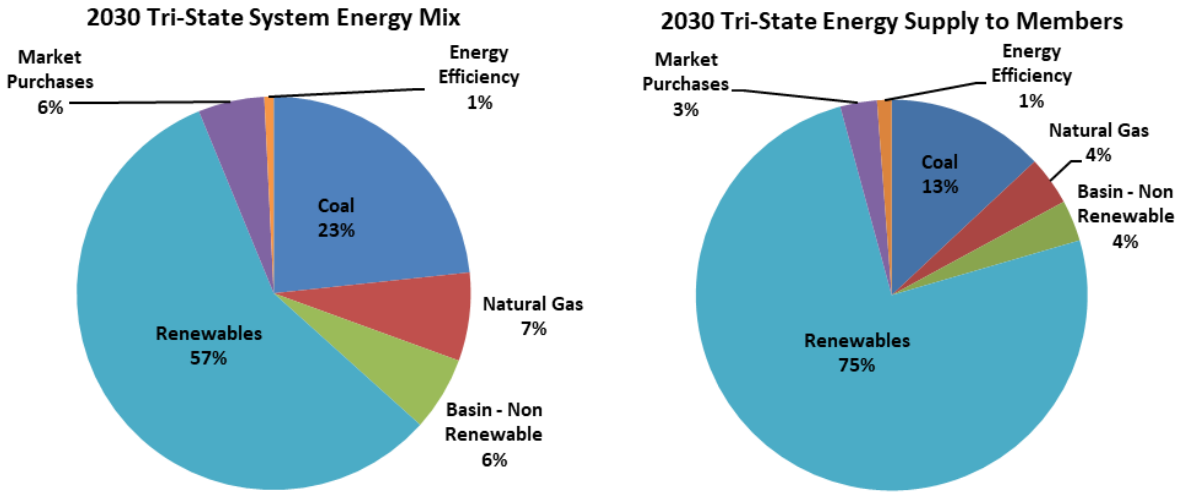


Table 8: Projected Annual Capacity Factors for Thermal Resources (Portfolio 1 – NEE)

Thermal Resource	2025	2026	2027	2028	2029	2030	2031
Craig 1	33%	-	-	-	-	-	-
Craig 2	36%	37%	38%	24%	-	-	-
Craig 3	19%	19%	19%	-	-	-	-
LRS 2	77%	78%	89%	88%	82%	75%	83%
LRS 3	68%	84%	65%	73%	83%	82%	80%
SPV 3	87%	87%	89%	77%	60%	42%	12%
Burlington	0%	0%	0%	0%	0%	0%	0%
Knutson	6%	5%	3%	0%	0%	0%	0%
Limon	5%	3%	0%	0%	0%	0%	0%
Pyramid	7%	1%	0%	0%	0%	0%	0%
Shafer	35%	35%	35%	35%	26%	19%	24%
GG-0006-2-wco	0%	0%	0%	0%	40%	40%	40%

Portfolio 1 (New ERA Expanded) – Environmental Analysis

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

[46] System Energy Mix reflects sales to Members and non-Members. "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases. Energy for Member Supply is only based on sales to Members and does not include Member-supplied energy in either the supply or sales.

Table 9: Environmental Impact - System Wide (Portfolio 1 – NEE) [47]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2025	12,244,922	5,556	7,270	0.0304	859	3,899,917,881	22,405
2026	11,962,306	6,093	7,512	0.0335	975	4,183,354,305	24,235
2027	11,750,117	5,940	7,360	0.0327	961	4,161,589,886	23,953
2028	9,874,804	5,208	6,125	0.0290	841	3,480,893,766	20,201
2029	9,043,741	7,796	6,571	0.0268	729	3,080,720,212	17,940
2030	7,345,275	10,258	6,986	0.0238	607	2,691,211,959	16,047
2031	6,399,384	9,943	6,815	0.0207	370	2,139,654,056	13,265
2032	5,656,566	9,627	6,510	0.0177	259	1,784,885,467	11,492
2033	5,818,338	9,697	6,570	0.0187	278	1,863,239,379	11,783
2034	5,682,522	9,640	6,485	0.0181	274	1,803,058,523	11,491
2035	5,813,155	9,712	6,584	0.0187	273	1,845,867,435	11,847
2036	5,570,335	9,577	6,460	0.0173	252	1,750,921,710	11,305
2037	5,706,630	9,672	6,538	0.0181	266	1,785,001,792	11,627
2038	5,448,317	8,616	6,119	0.0176	252	1,666,538,080	11,330
2039	5,553,097	8,731	6,199	0.0181	254	1,712,426,151	11,584
2040	5,180,884	7,717	5,792	0.0167	221	1,547,476,901	10,991
2041	5,164,345	7,364	5,705	0.0167	222	1,513,398,513	11,008
2042	5,000,692	6,947	5,545	0.0159	210	1,426,738,301	10,699
2043	4,973,141	6,509	5,436	0.0159	202	1,395,662,722	10,776
Total	**134,188,571**	**154,604**	**122,581**	**0.406**	**8,306**	**43,732,557,038**	**273,981**
Pounds/Gallons per MWh[48]	**902**	**1.04**	**0.82**	**0.000003**	**0.06**	**147**	**2.030**

[47] 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.

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

Table 10: Social Cost of Carbon Nominal Dollars – System Wide (Portfolio 1 – NEE)

Year	Annual Social Cost of Carbon
2025	$1,139,132,187
2026	$1,151,025,894
2027	$1,182,993,732
2028	$1,027,875,370
2029	$972,185,689
2030	$815,346,559
2031	$741,565,451
2032	$676,606,840
2033	$726,019,364
2034	$731,664,351
2035	$772,246,675
2036	$771,269,337
2037	$814,965,697
2038	$802,439,822
2039	$851,748,425
2040	$819,299,456
2041	$841,929,891
2042	$848,377,440
2043	$869,547,745

Table 11: Social Cost of Methane Nominal Dollars – System Wide (Portfolio 1 – NEE)

Year	Annual Social Cost of Methane
2025	$61,742,239
2026	$69,950,104
2027	$72,370,913
2028	$63,854,206
2029	$59,238,749
2030	$55,323,918
2031	$47,881,107
2032	$43,405,678
2033	$46,538,873
2034	$47,435,734
2035	$51,090,347
2036	$50,898,647
2037	$54,631,126
2038	$55,527,948
2039	$59,194,959
2040	$58,529,071
2041	$60,870,777
2042	$62,289,850
2043	$64,055,746

Table 12: GHG Emissions Reduction Percentages, Targets and Forecast (Portfolio 1 – NEE)

Year	Target[49]	Forecast
2025	26%	29%
2026	36%	39%
2027	46%	47%
2030	80%	80%

See Attachment D-1 for detailed GHG emissions calculations for the portfolio.

Portfolio 1 (New ERA Expanded) – Financial Analysis

The PVRR, net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and AFUDC, annual revenue requirement, and NPV by resource for the portfolio are shown below.

Table 13: Total Financial (Portfolio 1 – NEE)

$, Millions	Portfolio PVRR (2024 WACC 5.9%)	SCoC NPV (2.5%)	SCoM NPV (2.5%)	Portfolio PVRR inclusive of SCoC NPV	Portfolio PVRR inclusive of SCoC NPV & SCoM NPV
	$16,836	$12,911	$837	$29,746	$30,584
Difference to preferred plan (Nominal $)	$393	($18)	($1)	$375	$374

Table 14: Total Financial Generation and Transmission (Portfolio 1 – NEE)

$, Millions	Expansion Plan CapEx + AFUDC:	Difference to preferred plan
Generation (Nominal $)	$1,508	$971
Transmission (Nominal $)	$1,506	$389

Table 15: Annual Financial (Nominal $) (Portfolio 1 – NEE)

Year	Total Annual Revenue Requirement ($, Millions)
2025	$1,059
2026	$1,050
2027	$1,206
2028	$1,539
2029	$1,401
2030	$1,424
2031	$1,501

[49] 2020 ERP Phase I Settlement Agreement, at Sections 3.3.4. and 3.3.5 (Proceeding No. 20A-0528E).

Year	Total Annual Revenue Requirement ($, Millions)
2032	$1,518
2033	$1,552
2034	$1,531
2035	$1,529
2036	$1,597
2037	$1,634
2038	$1,679
2039	$1,717
2040	$1,711
2041	$1,785
2042	$1,835
2043	$1,921

[redacted]

[redacted]

[redacted]

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. A majority of the curtailments are in the New Mexico area. There are 400 MW of wind, 490 MW of solar, and 675 MW of battery storage (including hybrid batteries) built during the RAP in Portfolio 1 – NEE. The amount of curtailment is reduced to zero in 2030 as more batteries are built.

Table 17: Curtailed Intermittent Energy, Annual MWh (Portfolio 1 – NEE)

	Existing Wind	Existing Solar	Bid Wind	Bid Solar	Total
2025	0	185	0	0	185
2026	0	896	0	0	896
2027	0	1,429	0	0	1,429
2028	0	1,811	0	0	1,811
2029	0	52	0	124	176
2030	0	0	0	0	0
2031	0	0	0	0	0
RAP Total	**0**	**4,373**	**0**	**124**	**4,497**

Table 18: Seasonal Intermittent Resource Curtailments, Annual MWh (Portfolio 1 – NEE)

	Winter	Spring	Summer	Fall
2025	0	118	0	67
2026	13	713	39	131
2027	18	1,189	1	221
2028	61	954	69	727
2029	0	0	12	164
2030	0	0	0	0
2031	0	0	0	0
RAP Total	**92**	**2,974**	**121**	**1,310**

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

Table 19: Estimated PPA Curtailment Costs and Penalties, Real (2024) $ (Portfolio 1 – NEE)

	Wind ($)	Solar ($)
2025	$0	$23,999
2026	$0	$145,247
2027	$0	$224,019

2028	$0	$214,350
2029	$0	$18,138
2030	$0	$0
2031	$0	$0
RAP Total	**$0**	**$625,753**

Portfolio 1 (New ERA Expanded) – Transmission Analysis

Forecasted interconnection and network upgrade expenses resulting from the portfolio are shown in the table below.

Table 20: Transmission Interconnection & Network Upgrade Expenses Real (2024) $ (Portfolio 1 – NEE)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2028	100	ST-0019-1-ECO	$1.50	$5.85	
2029	200	WI-0013-3-ECO		$14.62	$30.00
2029	100	ST-0017-1-ECO	$1.50	$14.62	
2030	150	PC-0009-2P-ECO		$14.62	$130.00
2036	100	Battery	$1.50	$5.85	
2038	100	Wind + Battery		$5.85	
2038	100	Wind + Battery		$5.85	
2042	100	Wind		$14.62	$81.56
2042	100	Wind		$5.85	
2042	100	Wind		$5.85	
2043	100	Battery	$1.50	$5.85	
2043	100	Wind		$5.85	
Western Colorado (WCO) Transmission Area					
2026	50	ST-0002-5-WCO	$1.30	$10.94	
2027	140	PV-0004-5-WCO		$3.25	$47.06
2029	307	GG-0006-2-WCO	$1.70	$6.56	
2030	200	ST-0009-3-WCO	$1.50	$5.85	
2035	20	Geothermal Storage	$1.30	$3.25	
Wyoming (WYO) Transmission Area					
2030	200	WI-0013-2-WYO-WNE		$14.62	$119.24
2037	100	Wind + Battery		$6.56	
New Mexico (NM) Transmission Area)					
2028	100	PC-0018-1P-NM		$10.94	
2028	100	ST-0009-4-NM	$1.30	$3.25	
2029	100	PV-0004-4-NM		$10.94	$165.62
2033	100	Wind + Battery		$5.85	$363.20

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2033	100	Wind + Battery		$5.85	
2036	100	Wind + Battery		$5.85	
2041	100	Solar		$5.85	$56.46
2042	100	Solar		$5.85	

Portfolio 1 (New ERA Expanded) – Reliability Analysis

PRM, LOLH, and EUE results ("Level 1 Reliability Metrics") are as follows. "Level 2 Reliability Metrics" results can be found in Attachment E.

Planning Reserve Margin

The following table provides the annual PRM resulting from Portfolio 1 New ERA Expanded.

Table 21: RAP Planning Reserve Margin, % Annual (Portfolio 1 – NEE)

2025	2026	2027	2028	2029	2030	2031
24%	24%	26%	33%	52%	58%	35%

Table 22: Post-RAP Planning Reserve Margin, % Annual (Portfolio 1 – NEE)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
31%	31%	31%	33%	32%	31%	31%	33%	36%	34%	31%	31%

Loss of Load Hours

The following table provides the annual LoLH resulting from Portfolio 1 New ERA Expanded.

Table 23: RAP Loss of Load Probability, Hours (Portfolio 1 – NEE)

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

Table 24: Post-RAP Loss of Load Probability, Hours (Portfolio 1 – NEE)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE resulting from Portfolio 1 – NEE.

Table 25: RAP Expected Unserved Energy, Annual MWh (Portfolio 1 – NEE)

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

Table 26: Post-RAP Loss of Load Probability, Hours (Portfolio 1 – NEE)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

2. New ERA Limited Gas (NELG)

Assumptions unique to the portfolio are identified in Attachment B-3.

Portfolio 2 (New ERA Limited Gas) – Expansion Plan, Retirements, System Mix, and Capacity Factors

The expansion plan, DSM selected, plant retirements, system resource mix, and thermal unit capacity factors modeled for the portfolio are shown below.

Table 27: Expansion Plan (Portfolio 2 – NELG)

Year	Bid Project	Technology	Planning Region	Unit Size (MW)	Number of Units[55]	Total MW
2026	ST-0002-5-wco	4hr - Battery	West Colorado	50	1	50
2027	PV-0004-5-wco	Solar	West Colorado	140	1	140
	ST-0002-6-wco	4hr - Battery	West Colorado	100	1	100
2028	ST-0009-4-nm	4hr - Battery	New Mexico	100	1	100
	ST-0004-10-eco	4hr - Battery	East Colorado	100	1	100
	PC-0018-1P-nm	Solar / Battery	New Mexico	100	1	100
2029	ST-0017-1-eco	4hr - Battery	East Colorado	100	1	100
	WI-0013-3-eco	Wind	East Colorado	200	1	200
	PV-0004-4-nm	Solar	New Mexico	100	1	100
	GG-0006-1-wco	Combustion Turbine	West Colorado	38.36	8	307
2030	PC-0009-2P-eco	Solar / Battery	East Colorado	150	1	150
	WI-0013-2-wyo-wne	Wind	Wyoming / W.Neb	200	1	200
	ST-0009-3-wco	4hr - Battery	West Colorado	200	1	200
2033	-	Geothermal Storage	West Colorado	20	1	20
	-	Wind / Battery	New Mexico	100	1	100
2036	-	10hr - Battery	East Colorado	100	1	100
	-	Wind / Battery	East Colorado	100	1	100
	-	Wind / Battery	New Mexico	100	1	100
2037	-	Wind / Battery	East Colorado	100	1	100
	-	Wind / Battery	New Mexico	100	1	100
2042	-	Wind	East Colorado	100	4	400
	-	Solar	New Mexico	100	2	200
2043	-	Wind	Wyoming / W.Neb	100	1	100

The expansion plan also included the following EE levels:

- All plans include applicable Colorado energy efficiency targets in base assumptions.
- 2025: Low New Mexico Energy Efficiency and Low Wyoming Energy Efficiency were selected in the expansion plan of Portfolio 2 – NELG.

[55] Each bid is modeled as a single project for purposes of expansion plan selection.

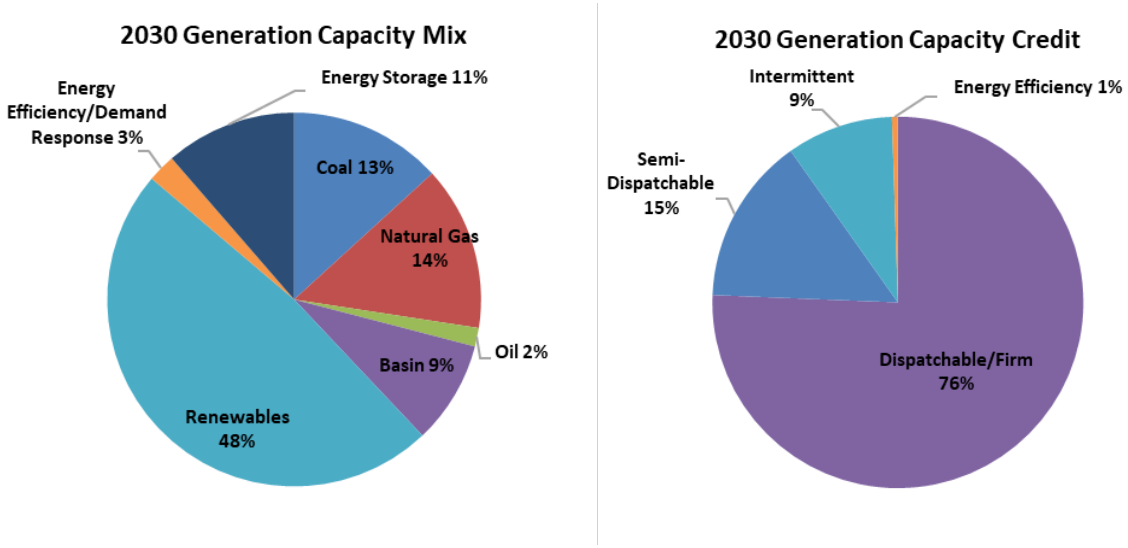
Unit retirements scheduled or selected in the modeling are shown in the following table.[56]

Table 28: Modeled Retirements (Portfolio 2 – NELG)

Location	MW	Technology	Date
Craig 1	427	Coal	12/31/2025
Craig 3	448	Coal	1/1/2028
Craig 2	410	Coal	9/30/2028
Springerville 3	418	Coal	3/1/2031[57]

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

Figure 4: Projected Tri-State System Capacity Mix 2030 (Portfolio 2 – NELG)[58, 59]



[56] 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). Tri-State's share of Craig 1 is 102 MW and Craig 2 is 98 MW. Craig 3 is modeled to retire on the date selected and approved in Phase I of the 2023 ERP.

[57] The New ERA award requires a March 1, 2031 retirement date for SPV 3, given the requirement for USDA to disperse all New ERA funds by September 30, 2031.

[58] "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases.

[59] Rounding of percentages may lead to values displayed that do not appear to total to 100 percent exactly.

Figure 5: Projected Tri-State System Energy Mix 2030 (Portfolio 2 – NELG)[60]

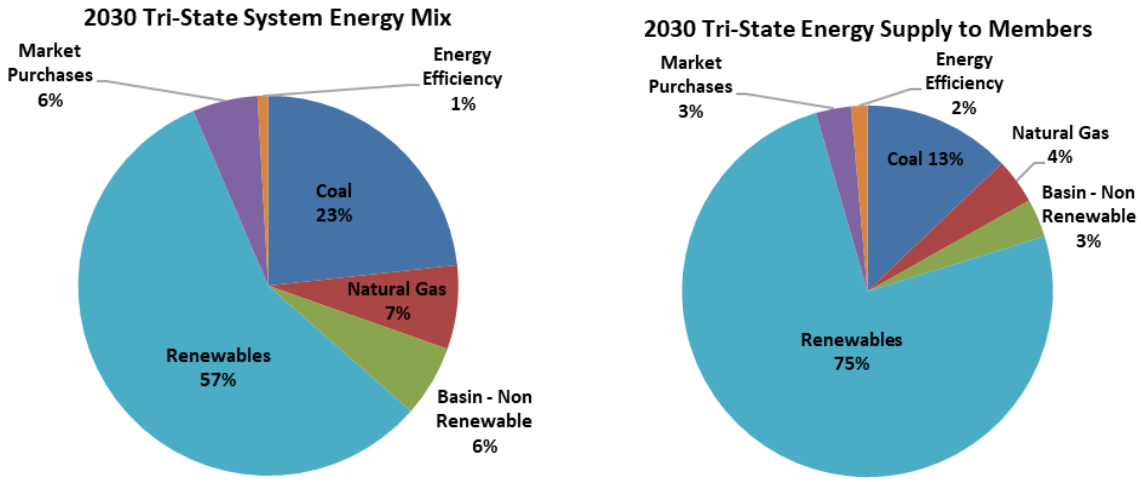


Table 29: Projected Annual Capacity Factors for Thermal Resources (Portfolio 2 – NELG)

Thermal Resource	2025	2026	2027	2028	2029	2030	2031
Craig 1	33%	-	-	-	-	-	-
Craig 2	36%	37%	38%	24%	-	-	-
Craig 3	19%	19%	19%	-	-	-	-
LRS 2	77%	78%	89%	88%	82%	75%	82%
LRS 3	67%	83%	64%	73%	83%	82%	80%
SPV 3	87%	87%	89%	77%	60%	42%	12%
Burlington	0%	0%	0%	0%	0%	0%	0%
Knutson	6%	5%	3%	0%	0%	0%	0%
Limon	4%	3%	0%	0%	0%	0%	0%
Pyramid	7%	1%	1%	0%	0%	0%	0%
Shafer	35%	35%	35%	35%	25%	18%	24%
GG-0006-1-wco	0%	0%	0%	0%	40%	40%	40%

Portfolio 2 (New ERA Limited Gas) – Environmental Analysis

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

[60] System Energy Mix reflects sales to Members and non-Members. "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases. Energy for Member Supply is only based on sales to Members and does not include Member-supplied energy in either the supply or sales.

Table 30: Environmental Impact - System Wide (Portfolio 2 – NELG) [61]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2025	12,244,922	5,556	7,270	0.0304	859	3,899,917,881	22,405
2026	11,942,684	6,082	7,499	0.0335	974	4,177,652,419	24,195
2027	11,727,659	5,926	7,347	0.0325	958	4,150,755,120	23,895
2028	9,879,304	5,209	6,129	0.0290	839	3,477,044,578	20,198
2029	9,036,223	7,796	6,566	0.0268	726	3,057,173,748	17,831
2030	7,334,742	10,249	6,979	0.0238	606	2,670,517,035	15,863
2031	6,390,985	9,941	6,811	0.0207	369	2,119,971,139	13,074
2032	5,643,142	9,626	6,504	0.0177	258	1,756,894,095	11,314
2033	5,846,331	9,721	6,629	0.0185	276	1,840,356,862	11,660
2034	5,721,745	9,570	6,526	0.0180	272	1,784,592,739	11,401
2035	5,816,518	9,313	6,528	0.0185	267	1,808,182,520	11,756
2036	5,617,103	9,352	6,437	0.0175	253	1,746,259,917	11,294
2037	5,668,595	8,918	6,321	0.0183	262	1,762,046,825	11,511
2038	5,370,590	7,698	5,885	0.0174	240	1,607,675,000	11,165
2039	5,444,002	7,486	5,871	0.0179	237	1,637,977,953	11,421
2040	5,033,242	6,320	5,407	0.0162	202	1,458,912,630	10,787
2041	5,081,355	6,125	5,424	0.0162	205	1,437,999,469	10,924
2042	4,923,968	5,904	5,263	0.0158	200	1,383,150,176	10,618
2043	4,899,783	5,453	5,150	0.0159	192	1,362,250,327	10,712
Total	**133,622,891**	**146,245**	**120,547**	**0.404**	**8,194**	**43,139,330,433**	**272,022**
Pounds/Gallons per MWh[62]	**946**	**1.04**	**0.85**	**0.000003**	**0.06**	**153**	**2.123**

[61] 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.

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

Table 31: Social Cost of Carbon Nominal Dollars – System Wide (Portfolio 2 – NELG)

Year	Annual Social Cost of Carbon
2025	$1,138,459,687
2026	$1,152,653,707
2027	$1,174,732,910
2028	$1,026,795,307
2029	$973,309,290
2030	$818,577,657
2031	$739,322,590
2032	$676,519,826
2033	$726,175,264
2034	$736,202,715
2035	$775,083,935
2036	$775,046,549
2037	$809,721,903
2038	$794,053,163
2039	$832,968,427
2040	$796,824,782
2041	$828,400,211
2042	$835,361,013
2043	$856,721,090

Table 32: Social Cost of Methane Nominal Dollars – System Wide (Portfolio 2 – NELG)

Year	Annual Social Cost of Methane
2025	$61,742,239
2026	$69,834,755
2027	$72,194,298
2028	$63,843,496
2029	$58,876,581
2030	$54,688,462
2031	$47,192,177
2032	$42,731,594
2033	$46,052,949
2034	$47,065,889
2035	$50,698,390
2036	$50,851,295
2037	$54,083,272
2038	$54,721,101
2039	$58,358,076
2040	$57,442,190
2041	$60,401,484
2042	$61,819,253
2043	$63,671,990

Table 33: GHG Emissions Reduction Percentages, Targets and Forecast (Portfolio 2 – NELG)

Year	Target[63]	Forecast
2025	26%	29%
2026	36%	39%
2027	46%	47%
2030	80%	80%

See Attachment D-2 for detailed GHG emissions calculations for the portfolio.

Portfolio 2 (New ERA Limited Gas) – Financial Analysis

The PVRR, net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and allowance for funds used during construction (AFUDC), annual revenue requirement, and NPV by resource for the portfolio are shown below.

Table 34: Total Financial (Portfolio 2 – NELG)

$, Millions	**Portfolio PVRR** (2024 WACC 5.9%)	**SCoC NPV (2.5%)**	**SCoM NPV (2.5%)**	**Portfolio PVRR inclusive of SCoC NPV**	**Portfolio PVRR inclusive of SCoC NPV & SCoM NPV**
	$16,841	$12,852	$831	$29,693	$30,524
Difference to preferred plan (Nominal $)	$399	($77)	($7)	$322	$314

Table 35: Total Financial Generation and Transmission (Portfolio 2 – NELG)

$, Millions	**Expansion Plan CapEx + AFUDC:**	**Difference to preferred plan**
Generation (Nominal $)	$370	($167)
Transmission (Nominal $)	$1,494	$378

Table 36: Annual Financial (Nominal $) (Portfolio 2 – NELG)

Year	Total Annual Revenue Requirement ($, Millions)
2025	$1,059
2026	$1,046
2027	$1,231
2028	$1,312
2029	$1,326

[63] 2020 ERP Phase I Settlement Agreement, at Sections 3.3.4. and 3.3.5 (Proceeding No. 20A-0528E).

Year	Total Annual Revenue Requirement ($, Millions)
2030	$1,432
2031	$1,510
2032	$1,571
2033	$1,572
2034	$1,556
2035	$1,552
2036	$1,623
2037	$1,670
2038	$1,709
2039	$1,746
2040	$1,781
2041	$1,821
2042	$1,907
2043	$1,962

[redacted]

64 [redacted]

65 [redacted]

66 [redacted]

67 [redacted]

68 [redacted]

[redacted]

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. A majority of the curtailments are in the New Mexico area. There are 400 MW of wind, 490 MW of solar, and 775 MW of battery storage (including hybrid batteries) built during the RAP. The amount of curtailment is reduced as more batteries are built.

Table 38: Curtailed Intermittent Energy, Annual MWh (Portfolio 2 – NELG)

	Existing Wind	Existing Solar	Bid Wind	Bid Solar	Total
2025	0	73	0	0	73
2026	0	962	0	0	962
2027	0	853	0	0	853
2028	0	1,132	0	11	1,143
2029	0	242	0	337	579
2030	0	0	0	0	0
2031	0	0	0	0	0
RAP Total	**0**	**3,262**	**0**	**348**	**3,610**

Table 39: Seasonal Intermittent Resource Curtailments, Annual MWh (Portfolio 2 – NELG)

	Winter	Spring	Summer	Fall
2025	0	50	0	23
2026	35	669	80	178
2027	33	703	32	85
2028	132	288	26	697
2029	0	0	288	291
2030	0	0	0	0
2031	0	0	0	0
RAP Total	**200**	**1,710**	**426**	**1,274**

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

Table 40: Estimated PPA Curtailment Costs and Penalties, Real (2024) $ (Portfolio 2 – NELG)

	Wind ($)	Solar ($)
2025	$0	$9,370
2026	$0	$156,979
2027	$0	$114,621
2028	$0	$143,388
2029	$0	$56,325
2030	$0	$0
2031	$0	$0
RAP Total	**$0**	**$480,683**

Portfolio 2 (New ERA Limited Gas) – Transmission Analysis

Forecasted interconnection and network upgrade expenses resulting from the portfolio are shown in the table below.

Table 41: Transmission Interconnection & Network Upgrade Expenses Real (2024) $ (Portfolio 2 – NELG)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2028	100	ST-0004-10-ECO			
2029	100	ST-0017-1-ECO	$1.50	$14.62	
2029	200	WI-0013-3-ECO		$14.62	$30.00
2030	150	PC-0009-2P-ECO		$14.62	$130.00
2036	100	Battery	$1.50	$5.85	
2036	100	Wind + Battery		$5.85	
2037	100	Wind + Battery		$5.85	
2042	100	Wind		$14.62	
2042	100	Wind		$5.85	$81.56
2042	100	Wind		$5.85	
2042	100	Wind		$5.85	
Western Colorado (WCO) Transmission Area					
2026	50	ST-0002-5-WCO	$1.30	$10.94	
2027	140	PV-0004-5-WCO		$3.25	$47.06
2027	100	ST-0002-6-WCO	$1.30	$3.25	
2029	307	GG-0006-1-WCO	$1.70	$6.56	
2030	200	ST-0009-3-WCO	$1.50	$5.85	
2033	20	Geothermal Storage	$1.30	$3.25	
Wyoming (WYO) Transmission Area					
2030	200	WI-0013-2-WYO-WNE		$14.62	$119.24

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2043	100	Wind		$6.56	
New Mexico (NM) Transmission Area)					
2028	100	PC-0018-1P-NM		$10.94	
2028	100	ST-0009-4-NM	$1.30	$3.25	
2029	100	PV-0004-4-NM		$10.94	$165.62
2033	100	Wind + Battery		$5.85	$363.20
2036	100	Wind + Battery		$5.85	
2037	100	Wind + Battery		$5.85	
2042	100	Solar		$5.85	$56.46
2042	100	Solar		$5.85	

Portfolio 2 (New ERA Limited Gas) – Reliability Analysis

PRM, LOLH, and EUE results ("Level 1 Reliability Metrics") are as follows. "Level 2 Reliability Metrics" results can be found in Attachment E.

Planning Reserve Margin

The following table provides the annual PRM resulting from Portfolio 2 – NELG.

Table 42: RAP Planning Reserve Margin, % Annual (Portfolio 2 – NELG)

2025	2026	2027	2028	2029	2030	2031
24%	24%	26%	36%	54%	59%	36%

Table 43: Post-RAP Planning Reserve Margin, % Annual (Portfolio 2 – NELG)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
32%	31%	31%	32%	32%	33%	31%	34%	36%	34%	32%	31%

Loss of Load Hours

The following table provides the annual LoLH resulting from Portfolio 2 – NELG.

Table 44: RAP Loss of Load Probability, Hours (Portfolio 2 – NELG)

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

Table 45: Post-RAP Loss of Load Probability, Hours (Portfolio 2 - NELG)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE resulting from Portfolio 2 – NELG.

Table 46: RAP Expected Unserved Energy, Annual MWh (Portfolio 2 - NELG)

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

Table 47: Post-RAP Loss of Load Probability, Hours (Portfolio 2 - NELG)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

3. New ERA Gas Flexibility (FLEX)

Assumptions unique to the portfolio are identified in Attachment B-3.

Portfolio 3 (New ERA Gas Flexibility) – Expansion Plan, Retirements, System Mix, and Capacity Factors

The expansion plan, DSM selected, plant retirements, system resource mix, and thermal unit capacity factors modeled for the portfolio are shown below.

Table 48: Expansion Plan (Portfolio 3 – FLEX)

Year	Bid Project	Technology	Planning Region	Unit Size (MW)	Number of Units[69]	Total MW
2026	ST-0002-5-wco	4hr - Battery	West Colorado	50	1	50
2028	ST-0009-4-nm	4hr - Battery	New Mexico	100	1	100
	PC-0018-1P-nm	Solar / Battery	New Mexico	100	1	100
2029	ST-0018-1-eco	4hr - Battery	East Colorado	50	1	50
	ST-0017-1-eco	4hr - Battery	East Colorado	100	1	100
	ST-0010-4-eco	4hr - Battery	East Colorado	150	1	150
	WI-0016-1-eco	Wind	East Colorado	297	1	297
	PV-0004-4-nm	Solar	New Mexico	100	1	100
	GG-0006-2-wco	Combustion Turbine	West Colorado	38.36	8	307
2030	ST-0009-3-wco	4hr - Battery	West Colorado	200	1	200
	WI-0013-2-wyo-wne	Wind	Wyoming / W.Neb	200	1	200
	PC-0009-2P-eco	Solar / Battery	East Colorado	150	1	150
2033	-	Wind / Battery	New Mexico	100	1	100
	-	Geothermal Storage	West Colorado	20	1	20
2036	-	Wind / Battery	New Mexico	100	2	200
	-	10hr - Battery	West Colorado	100	1	100
	-	Solar	West Colorado	100	1	100
2038	-	Wind / Battery	East Colorado	100	2	200
2041	-	Solar	West Colorado	100	1	100
2042	-	Wind	East Colorado	100	3	300
	-	Solar	New Mexico	100	1	100
	-	Solar	West Colorado	100	2	200
2043	-	Wind	Wyoming / W.Neb	100	1	100

The expansion plan also included the following EE levels:

- All plans include applicable Colorado energy efficiency targets in base assumptions.
- 2025: Low New Mexico Energy Efficiency and Low Wyoming Energy Efficiency were selected in the expansion plan of Portfolio 3 – FLEX.

[69] Each bid is modeled as a single project for purposes of expansion plan selection.

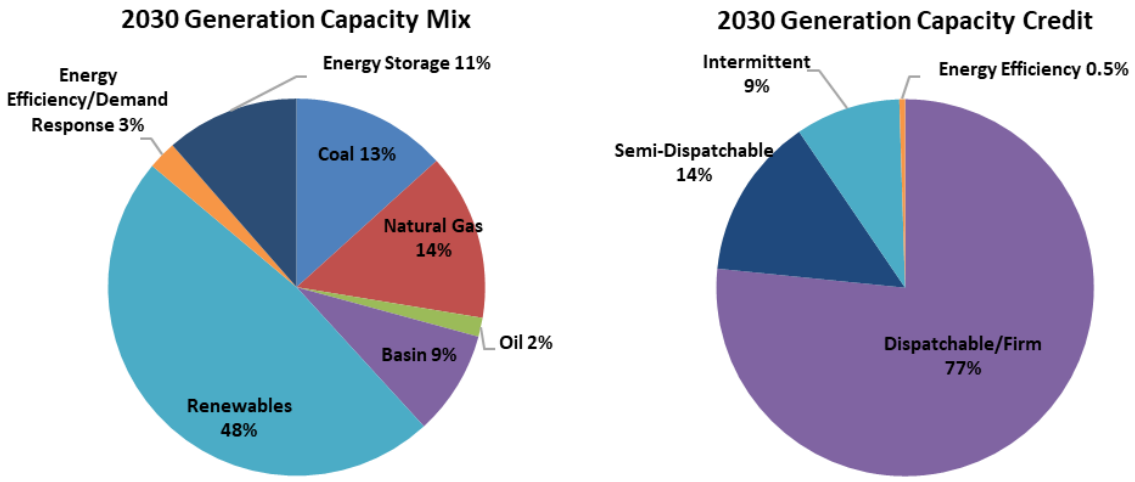
Unit retirements scheduled or selected in the modeling are shown in the following table.[70]

Table 49: Modeled Retirements (Portfolio 3 – FLEX)

Location	MW	Technology	Date
Craig 1	427	Coal	12/31/2025
Craig 3	448	Coal	1/1/2028
Craig 2	410	Coal	9/30/2028
Springerville 3	418	Coal	3/1/2031[71]

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

Figure 6: Projected Tri-State System Capacity Mix 2030 (Portfolio 3 – FLEX)[72, 73]



[70] 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). Tri-State's share of Craig 1 is 102 MW and Craig 2 is 98 MW. Craig 3 is modeled to retire on the date selected and approved in Phase I of the 2023 ERP.

[71] The New ERA award requires a March 1, 2031 retirement date for SPV 3, given the requirement for USDA to disperse all New ERA funds by September 30, 2031.

[72] "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases.

[73] Rounding of percentages may lead to values displayed that do not appear to total to 100 percent exactly.

Figure 7: Projected Tri-State System Energy Mix 2030 (Portfolio 3 – FLEX)[74]

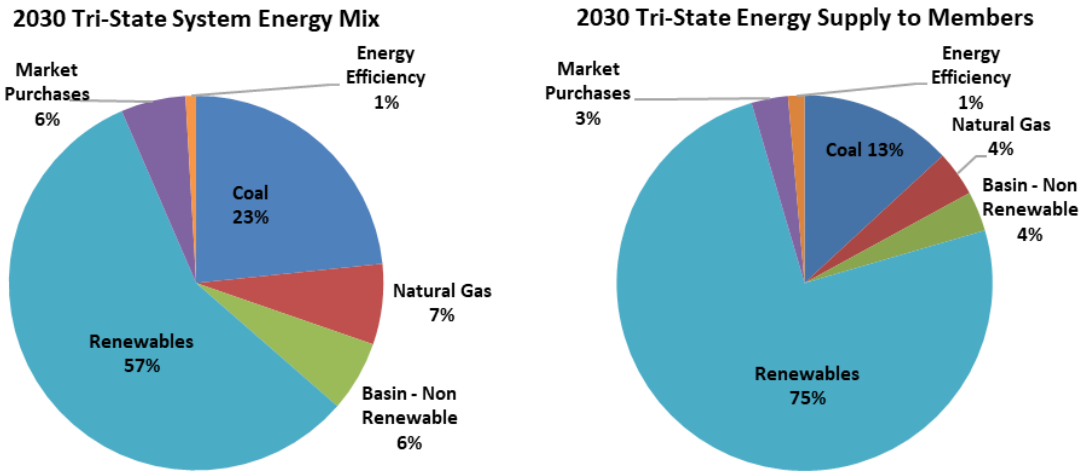


Table 50: Projected Annual Capacity Factors for Thermal Resources (Portfolio 3 – FLEX)

Thermal Resource	2025	2026	2027	2028	2029	2030	2031
Craig 1	33%	-	-	-	-	-	-
Craig 2	36%	37%	38%	24%	-	-	-
Craig 3	19%	19%	19%	-	-	-	-
LRS 2	77%	78%	89%	88%	82%	75%	82%
LRS 3	67%	83%	52%	70%	83%	82%	80%
SPV 3	87%	87%	89%	75%	60%	42%	12%
Burlington	0%	0%	0%	0%	0%	0%	0%
Knutson	6%	5%	3%	0%	0%	0%	0%
Limon	4%	3%	0%	0%	0%	0%	0%
Pyramid	7%	1%	3%	0%	0%	0%	0%
Shafer	35%	35%	35%	35%	22%	16%	21%
GG-0006-2-wco	0%	0%	0%	0%	40%	40%	40%

Portfolio 3 (New ERA Gas Flexibility) – Environmental Analysis

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

[74] System Energy Mix reflects sales to Members and non-Members. "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases. Energy for Member Supply is only based on sales to Members and does not include Member-supplied energy in either the supply or sales.

Table 51: Environmental Impact - System Wide (Portfolio 3 – FLEX) [75]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2025	12,244,922	5,556	7,270	0.0304	859	3,899,917,881	22,405
2026	11,943,290	6,082	7,500	0.0335	974	4,177,494,353	24,196
2027	11,568,153	5,770	7,226	0.0311	936	4,045,072,240	23,327
2028	9,779,075	5,148	6,077	0.0284	818	3,407,958,468	19,883
2029	8,967,361	7,781	6,521	0.0267	724	3,038,458,535	17,867
2030	7,315,232	10,260	6,967	0.0237	605	2,657,827,563	16,039
2031	6,350,647	9,935	6,786	0.0206	367	2,096,814,877	13,210
2032	5,635,838	9,629	6,501	0.0176	257	1,753,123,139	11,482
2033	5,820,676	9,711	6,616	0.0184	274	1,827,280,223	11,797
2034	5,720,467	9,667	6,551	0.0179	272	1,784,031,850	11,563
2035	5,832,550	9,741	6,639	0.0185	270	1,814,000,679	11,908
2036	5,602,277	9,601	6,471	0.0175	255	1,753,655,478	11,394
2037	5,653,752	9,638	6,515	0.0177	261	1,752,980,829	11,500
2038	5,458,897	8,694	6,154	0.0176	252	1,654,130,594	11,329
2039	5,548,435	8,783	6,219	0.0180	252	1,690,762,833	11,575
2040	5,178,596	7,783	5,816	0.0165	220	1,530,568,107	10,959
2041	5,191,519	7,349	5,728	0.0167	223	1,503,734,603	11,078
2042	5,095,815	6,784	5,539	0.0165	218	1,460,467,941	10,943
2043	5,039,030	6,269	5,391	0.0164	208	1,427,643,128	10,961
Total	**133,946,532**	**154,182**	**122,485**	**0.404**	**8,246**	**43,275,923,319**	**273,416**
Pounds/Gallons per MWh[76]	**949**	**1.09**	**0.87**	**0.000003**	**0.06**	**153**	**2.134**

[75] 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.

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

Table 52: Social Cost of Carbon Nominal Dollars – System Wide (Portfolio 3 – FLEX)

Year	Annual Social Cost of Carbon
2025	$1,138,459,687
2026	$1,152,712,185
2027	$1,158,755,608
2028	$1,016,378,097
2029	$965,892,008
2030	$816,400,243
2031	$734,656,192
2032	$675,644,270
2033	$722,988,638
2034	$736,038,329
2035	$777,220,279
2036	$773,000,815
2037	$807,601,751
2038	$807,109,612
2039	$848,947,387
2040	$819,836,199
2041	$846,359,980
2042	$864,515,211
2043	$881,068,315

Table 53: Social Cost of Methane Nominal Dollars – System Wide (Portfolio 3 – FLEX)

Year	Annual Social Cost of Methane
2025	$61,742,239
2026	$69,836,579
2027	$70,477,977
2028	$62,847,444
2029	$58,997,890
2030	$55,296,246
2031	$47,683,283
2032	$43,367,675
2033	$46,595,924
2034	$47,733,888
2035	$51,349,932
2036	$51,298,669
2037	$54,036,042
2038	$55,522,239
2039	$59,145,438
2040	$58,361,648
2041	$61,255,841
2042	$63,710,822
2043	$65,154,538

Table 54: GHG Emissions Reduction Percentages, Targets and Forecast (Portfolio 3 – FLEX)

Year	Target[77]	Forecast
2025	26%	29%
2026	36%	39%
2027	46%	47%
2030	80%	80%

See Attachment D-3 for detailed GHG emissions calculations for the portfolio.

Portfolio 3 (New ERA Gas Flexibility) – Financial Analysis

The PVRR, net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and AFUDC, annual revenue requirement, and NPV by resource for the portfolio are shown below.

Table 55: Total Financial (Portfolio 3 – FLEX)

$, Millions	Portfolio PVRR (2024 WACC 5.9%)	SCoC NPV (2.5%)	SCoM NPV (2.5%)	Portfolio PVRR inclusive of SCoC NPV	Portfolio PVRR inclusive of SCoC NPV & SCoM NPV
	$16,761	$12,891	$836	$29,652	$30,488
Difference to preferred plan (Nominal $)	$318	($38)	($2)	$281	$278

Table 56: Total Financial Generation and Transmission (Portfolio 3 – FLEX)

$, Millions	Expansion Plan CapEx + AFUDC:	Difference to preferred plan
Generation (Nominal $)	$1,129	$592
Transmission (Nominal $)	$1,457	$340

Table 57: Annual Financial (Nominal $) (Portfolio 3 – FLEX)

Year	Total Annual Revenue Requirement ($, Millions)
2025	$1,059
2026	$1,050
2027	$1,220
2028	$1,371
2029	$1,399
2030	$1,427
2031	$1,503

[77] 2020 ERP Phase I Settlement Agreement, at Sections 3.3.4. and 3.3.5 (Proceeding No. 20A-0528E).

Year	Total Annual Revenue Requirement ($, Millions)
2032	$1,525
2033	$1,557
2034	$1,537
2035	$ 1,531
2036	$1,607
2037	$1,639
2038	$1,697
2039	$1,726
2040	$1,751
2041	$1,785
2042	$1,833
2043	$1,906

[redacted]

78 [redacted]

79 [redacted]

80 [redacted]

81 [redacted]

82 [redacted]

[redacted]

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. A majority of the curtailments are in the New Mexico area. There are 497 MW of wind, 350 MW of solar, and 775 MW of battery storage (including hybrid batteries) built during the RAP. The amount of curtailment is reduced as more batteries are built.

Table 59: Curtailed Intermittent Energy, Annual MWh (Portfolio 3 – FLEX)

	Existing Wind	Existing Solar	Bid Wind	Bid Solar	Total
2025	0	101	0	0	101
2026	0	770	0	0	770
2027	0	1,019	0	0	1,019
2028	0	847	0	7	854
2029	0	9	0	207	216
2030	0	0	0	0	0
2031	0	0	0	0	0
RAP Total	**0**	**2,746**	**0**	**214**	**2,960**

Table 60: Seasonal Intermittent Resource Curtailments, Annual MWh (Portfolio 3 – FLEX)

	Winter	Spring	Summer	Fall
2025	0	60	0	41
2026	13	601	79	77
2027	18	725	52	224
2028	49	412	1	392
2029	0	0	70	146
2030	0	0	0	0
2031	0	0	0	0
RAP Total	**80**	**1,798**	**202**	**880**

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

Table 61: Estimated PPA Curtailment Costs and Penalties, Real (2024) $ (Portfolio 3 – FLEX)

	Wind ($)	Solar ($)
2025	$0	$13,166
2026	$0	$125,261
2027	$0	$151,371
2028	$0	$107,958

2029	$0	$18,876
2030	$0	$0
2031	$0	$0
RAP Total	**$0**	**$416,632**

Portfolio 3 (New ERA Gas Flexibility) – Transmission Analysis

Forecasted interconnection and network upgrade expenses resulting from the portfolio are shown in the table below.

Table 62: Transmission Interconnection & Network Upgrade Expenses Real (2024) $ (Portfolio 3 – FLEX)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2029	150	ST-0010-4-ECO	$1.50	$5.85	
2029	100	ST-0017-1-ECO	$1.50	$14.62	
2029	50	ST-0018-1-ECO	$1.50	$5.85	
2029	297	WI-0016-1-ECO		$14.62	$30.00
2030	150	PC-0009-2P-ECO		$14.62	$130.00
2038	100	Wind + Battery		$5.85	$81.56
2038	100	Wind + Battery		$5.85	
2042	100	Wind		$14.62	
2042	100	Wind		$5.85	
2042	100	Wind		$5.85	
Western Colorado (WCO) Transmission Area					
2026	50	ST-0002-5-WCO	$1.30	$10.94	
2029	307	GG-0006-2-WCO	$1.70	$6.56	
2030	200	ST-0009-3-WCO	$1.50	$5.85	
2033	20	Geothermal Storage	$1.30	$3.25	
2036	100	Solar		$5.85	
2036	100	Battery	$1.50	$5.85	
2041	100	Solar		$3.25	
2042	100	Solar		$6.56	
2042	100	Solar		$6.56	
Wyoming (WYO) Transmission Area					
2030	200	WI-0013-2-WYO-WNE		$14.62	$119.24
2043	100	Wind		$6.56	
New Mexico (NM) Transmission Area)					
2028	100	PC-0018-1P-NM		$10.94	
2028	100	ST-0009-4-NM	$1.30	$3.25	
2029	100	PV-0004-4-NM		$10.94	$165.62

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2033	100	Wind + Battery		$5.85	$363.20
2036	100	Wind + Battery		$5.85	
2036	100	Wind + Battery		$5.85	
2042	100	Solar		$5.85	$56.46

Portfolio 3 (New ERA Gas Flexibility) – Reliability Analysis

PRM, LOLH, and EUE results ("Level 1 Reliability Metrics") are as follows. "Level 2 Reliability Metrics" results can be found in Attachment E.

Planning Reserve Margin

The following table provides the annual PRM resulting from Portfolio 3 – FLEX.

Table 63: RAP Planning Reserve Margin, % Annual (Portfolio 3 – FLEX)

2025	2026	2027	2028	2029	2030	2031
24%	24%	26%	33%	54%	58%	36%

Table 64: Post-RAP Planning Reserve Margin, % Annual (Portfolio 3 – FLEX)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
31%	31%	31%	32%	32%	31%	31%	33%	36%	34%	31%	31%

Loss of Load Hours

The following table provides the annual LoLH resulting from Portfolio 3 – FLEX.

Table 65: RAP Loss of Load Probability, Hours (Portfolio 3 – FLEX)

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

Table 66: Post-RAP Loss of Load Probability, Hours (Portfolio 3 – FLEX)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE resulting from Portfolio 3 – FLEX.

Table 67: RAP Expected Unserved Energy, Annual MWh (Portfolio 3 – FLEX)

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

Table 68: Post-RAP Loss of Load Probability, Hours (Portfolio 3 – FLEX)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

4. FLEX Shafer Replacement (FLEXSR)

Assumptions unique to the portfolio are identified in Attachment B-3.

Portfolio 4 (FLEX Shafer Replacement) – Expansion Plan, Retirements, System Mix, and Capacity Factors

The expansion plan, DSM selected, plant retirements, system resource mix, and thermal unit capacity factors modeled for the portfolio are shown below.

Table 69: Expansion Plan (Portfolio 4 – FLEXSR)

Year	Project	Technology	Planning Region	Unit Size (MW)	Number of Units[83]	Total MW
2026	ST-0002-5-wco	4hr - Battery	West Colorado	50	1	50
2027	ST-0004-6-eco	4hr - Battery	East Colorado	150	1	150
2028	ST-0009-4-nm	4hr - Battery	New Mexico	100	1	100
	ST-0004-10-eco	4hr - Battery	East Colorado	100	1	100
	PV-0006-8-eco	Solar	East Colorado	200	1	200
	PC-0018-1P-nm	Solar / Battery	New Mexico	100	1	100
2029	WI-0013-3-eco	Wind	East Colorado	200	1	200
	GG-0006-2-wco	Combustion Turbine	West Colorado	38.36	8	307
2030	ST-0009-3-wco	4hr - Battery	West Colorado	200	1	200
	WI-0013-2-wyo-wne	Wind	Wyoming/ W. Neb.	200	1	200
2033	-	Wind / Battery	East Colorado	100	2	200
2036	-	Wind / Battery	New Mexico	100	2	200
	-	Wind / Battery	East Colorado	100	1	100
	-	Geothermal Storage	West Colorado	20	1	20
	-	Solar	New Mexico	100	1	100
2037	-	Wind / Battery	East Colorado	100	1	100
2038	-	Wind / Battery	East Colorado	100	1	100
	-	Wind / Battery	New Mexico	100	1	100
2042	-	Solar	New Mexico	100	2	200
	-	Wind	Wyoming/ W. Neb.	100	1	100
	-	Wind	East Colorado	100	2	200
2043	-	Wind / Battery	East Colorado	100	1	100

The expansion plan also included the following EE levels:

- All plans include applicable Colorado energy efficiency targets in base assumptions.
- 2025: Low New Mexico Energy Efficiency and Low Wyoming Energy Efficiency were selected in the expansion plan of Portfolio 4 – FLEXSR.

[83] Each bid is modeled as a single project for purposes of expansion plan selection.

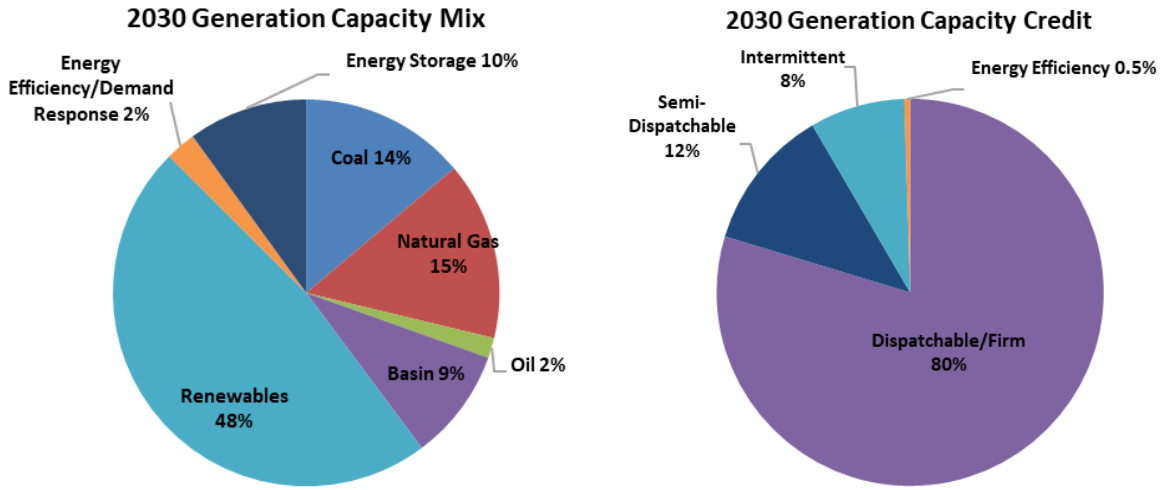
Unit retirements scheduled or selected in the modeling are shown in the following table.[84]

Table 70: Modeled Retirements (Portfolio 4 – FLEXSR)

Location	MW	Technology	Date
Craig 1	427	Coal	12/31/2025
Craig 3	448	Coal	1/1/2028
Craig 2	410	Coal	9/30/2028
Springerville 3	418	Coal	3/1/2031[85]

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

Figure 8: Projected Tri-State System Capacity Mix 2030 (Portfolio 4 – FLEXSR)[86, 87]



[84] 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). Tri-State's share of Craig 1 is 102 MW and Craig 2 is 98 MW. Craig 3 is modeled to retire on the date selected and approved in Phase I of the 2023 ERP.

[85] The New ERA award requires a March 1, 2031 retirement date for SPV 3, given the requirement for USDA to disperse all New ERA funds by September 30, 2031.

[86] "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases.

[87] Rounding of percentages may lead to values displayed that do not appear to total to 100 percent exactly.

Figure 9: Projected Tri-State System Energy Mix 2030 (Portfolio 4 – FLEXSR)[88]

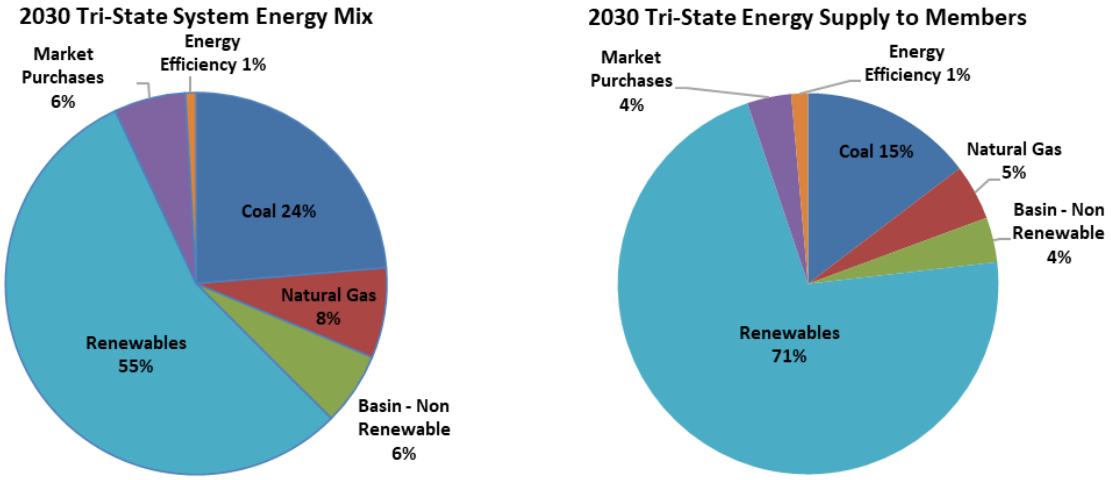


Table 71: Projected Annual Capacity Factors for Thermal Resources (Portfolio 4 – FLEXSR)

Thermal Resource	2025	2026	2027	2028	2029	2030	2031
Craig 1	33%	-	-	-	-	-	-
Craig 2	36%	37%	38%	24%	-	-	-
Craig 3	19%	19%	19%	-	-	-	-
LRS 2	77%	78%	89%	88%	82%	75%	83%
LRS 3	67%	83%	53%	70%	82%	82%	80%
SPV 3	87%	87%	89%	75%	65%	42%	12%
Burlington	0%	0%	0%	0%	0%	0%	0%
Knutson	6%	5%	3%	0%	0%	0%	0%
Limon	4%	3%	0%	0%	0%	0%	0%
Pyramid	7%	1%	3%	0%	0%	0%	0%
Shafer	35%	35%	35%	35%	25%	22%	23%
GG-0006-2-wco	0%	0%	0%	0%	40%	40%	40%

Portfolio 4 (FLEX Shafer Replacement) – Environmental Analysis

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

[88] System Energy Mix reflects sales to Members and non-Members. "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases. Energy for Member Supply is only based on sales to Members and does not include Member-supplied energy in either the supply or sales.

Table 72: Environmental Impact - System Wide (Portfolio 4 – FLEXSR) [89]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2025	12,244,922	5,556	7,270	0.0304	859	3,899,917,881	22,405
2026	11,942,421	6,082	7,499	0.0335	974	4,177,610,423	24,195
2027	11,568,735	5,770	7,227	0.0311	937	4,046,667,348	23,331
2028	9,819,361	5,161	6,103	0.0283	814	3,399,083,138	19,893
2029	9,204,229	7,855	6,616	0.0273	767	3,162,829,891	18,345
2030	7,412,404	10,284	7,047	0.0238	610	2,702,448,101	16,151
2031	6,458,059	9,980	6,884	0.0207	371	2,133,619,472	13,382
2032	5,712,026	9,667	6,578	0.0177	259	1,771,382,260	11,617
2033	5,853,864	9,745	6,652	0.0185	275	1,823,859,347	11,905
2034	5,797,935	9,690	6,616	0.0180	276	1,814,833,359	11,665
2035	5,898,663	9,785	6,694	0.0187	274	1,828,879,124	12,058
2036	5,625,841	9,611	6,460	0.0178	260	1,775,162,952	11,446
2037	5,698,331	9,682	6,499	0.0184	270	1,777,568,735	11,664
2038	5,351,664	8,533	6,016	0.0175	249	1,631,722,206	11,143
2039	5,433,584	8,599	6,069	0.0180	250	1,664,645,441	11,377
2040	5,111,931	7,566	5,683	0.0167	220	1,515,089,860	10,911
2041	5,218,379	7,217	5,684	0.0171	227	1,526,405,089	11,155
2042	5,033,011	6,829	5,500	0.0163	216	1,447,560,576	10,793
2043	4,988,533	6,377	5,382	0.0162	206	1,414,798,721	10,834
Total	**134,373,893**	**153,989**	**122,479**	**0.406**	**8,315**	**43,514,083,924**	**274,271**
Pounds/Gallons per MWh[90]	**952**	**1.09**	**0.87**	**0.000003**	**0.06**	**154**	**2.141**

[89] 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.

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

Table 73: Social Cost of Carbon Nominal Dollars – System Wide (Portfolio 4 – FLEXSR)

Year	Annual Social Cost of Carbon
2025	$1,138,459,687
2026	$1,152,628,339
2027	$1,158,813,840
2028	$1,020,565,222
2029	$991,405,565
2030	$827,244,896
2031	$747,081,881
2032	$684,777,928
2033	$727,110,962
2034	$746,005,989
2035	$786,030,277
2036	$776,252,143
2037	$813,969,586
2038	$791,254,956
2039	$831,374,435
2040	$809,282,328
2041	$850,738,875
2042	$853,860,285
2043	$872,238,852

Table 74: Social Cost of Methane Nominal Dollars – System Wide (Portfolio 4 – FLEXSR)

Year	Annual Social Cost of Methane
2025	$61,742,239
2026	$69,833,899
2027	$70,489,792
2028	$62,881,612
2029	$60,575,560
2030	$55,682,337
2031	$48,304,507
2032	$43,879,284
2033	$47,023,762
2034	$48,155,833
2035	$51,996,947
2036	$51,534,377
2037	$54,805,537
2038	$54,614,207
2039	$58,132,606
2040	$58,102,968
2041	$61,679,010
2042	$62,837,645
2043	$64,400,027

Table 75: GHG Emissions Reduction Percentages, Targets and Forecast (Portfolio 4 – FLEXSR)

Year	Target[91]	Forecast
2025	26%	29%
2026	36%	39%
2027	46%	47%
2030	80%	80%

See Attachment D-4 for detailed GHG emissions calculations for the portfolio.

Portfolio 4 (FLEX Shafer Replacement) – Financial Analysis

The PVRR, net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and AFUDC, annual revenue requirement, and NPV by resource for the portfolio are shown below.

Table 76: Total Financial (Portfolio 4 – FLEXSR)

$, Millions	Portfolio PVRR (2024 WACC 5.9%)	SCoC NPV (2.5%)	SCoM NPV (2.5%)	Portfolio PVRR inclusive of SCoC NPV	Portfolio PVRR inclusive of SCoC NPV & SCoM NPV
	$16,443	$12,928	$838	$29,371	$30,210

Table 77: Total Financial Generation and Transmission (Portfolio 4 – FLEXSR)

$, Millions	Expansion Plan CapEx + AFUDC:
Generation (Nominal $)	$537
Transmission (Nominal $)	$1,116

Table 78: Annual Financial (Nominal $) (Portfolio 4 – FLEXSR)

Year	Total Annual Revenue Requirement ($, Millions)
2025	$1,059
2026	$1,050
2027	$1,227
2028	$1,306
2029	$1,362
2030	$1,383
2031	$1,435
2032	$1,489
2033	$1,509
2034	$1,511
2035	$1,509

[91] 2020 ERP Phase I Settlement Agreement, at Sections 3.3.4. and 3.3.5 (Proceeding No. 20A-0528E).

Year	Total Annual Revenue Requirement ($, Millions)
2036	$1,599
2037	$1,606
2038	$1,669
2039	$1,695
2040	$1,702
2041	$1,745
2042	$1,779
2043	$1,855

[redacted]

92 [redacted]

93 [redacted]

94 [redacted]

95

96 [redacted]

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. A majority of the curtailments are in the New Mexico area. There are 400 MW of wind, 300 MW of solar, and 650 MW of battery storage (including hybrid batteries) built during the RAP. The amount of curtailment is reduced as more batteries are built.

Table 80: Curtailed Intermittent Energy, Annual MWh (Portfolio 4 – FLEXSR)

	Existing Wind	Existing Solar	Bid Wind	Bid Solar	Total
2025	0	73	0	0	73
2026	0	945	0	0	945
2027	0	1,432	0	0	1,432
2028	0	707	0	10	717
2029	0	453	0	20	473
2030	0	0	0	0	0
2031	0	0	0	0	0
RAP Total	**0**	**3,610**	**0**	**30**	**3,640**

Table 81: Seasonal Intermittent Resource Curtailments, Annual MWh (Portfolio 4 – FLEXSR)

	Winter	Spring	Summer	Fall
2025	0	50	0	23
2026	13	672	77	183
2027	19	1,127	58	228
2028	44	527	0	146
2029	0	0	1	472
2030	0	0	0	0
2031	0	0	0	0
RAP Total	**76**	**2,376**	**136**	**1,052**

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

Table 82: Estimated PPA Curtailment Costs and Penalties, Real (2024) $ (Portfolio 4 – FLEXSR)

	Wind ($)	Solar ($)
2025	$0	$9,370
2026	$0	$152,487
2027	$0	$193,537
2028	$0	$90,037
2029	$0	$51,807
2030	$0	$0
2031	$0	$0
RAP Total	**$0**	**$497,237**

Portfolio 4 (FLEX Shafer Replacement) – Transmission Analysis

Forecasted interconnection and network upgrade expenses resulting from the portfolio are shown in the table below.

As described in the Executive Summary Portfolio Analysis section above and in Attachment G, Tri-State analyzed Portfolio 4 – FLEXSR bid selections for transmission interconnection and upgrade cost considerations and the potential to utilize surplus interconnection, and implemented transmission modeling optimizations. As a result of this analysis, the FLEXSR preferred portfolio avoids significant transmission upgrade costs during the RAP.

Table 83: Transmission Interconnection & Network Upgrade Expenses Real (2024) $ (Portfolio 4 – FLEXSR)

Year	**Size** *(MW)*	**Type**	**Interconnection Cost** *($M)*	**Network Upgrade at POI Cost** *($M)*	**Network Upgrade for Size** *($M)*
Eastern Colorado (ECO) Transmission Area					
2027	150	ST-0004-6-ECO	$0.00		
2028	200	PV-0006-8-ECO		$5.85	
2028	100	ST-0004-10-ECO			
2029	200	WI-0013-3-ECO		$14.62	$30.00
2033	100	Wind + Battery		$5.85	$81.56
2033	100	Wind + Battery		$5.85	
2036	100	Wind + Battery		$5.85	
2037	100	Wind + Battery		$5.85	
2038	100	Wind + Battery		$5.85	$148.74
2042	100	Wind		$5.85	
2042	100	Wind		$5.85	
2043	100	Wind + Battery		$5.85	
Western Colorado (WCO) Transmission Area					
2026	50	ST-0002-5-WCO	$1.30	$10.94	
2029	307	GG-0006-2-WCO	$1.70	$6.56	
2030	200	ST-0009-3-WCO	$1.50	$5.85	
2036	20	Geothermal Storage	$1.30	$3.25	
Wyoming (WYO) Transmission Area					
2030	200	WI-0013-2-WYO-WNE		$14.62	
2042	100	Wind		$6.56	
New Mexico (NM) Transmission Area)					
2028	100	PC-0018-1P-NM		$10.94	
2028	100	ST-0009-4-NM	$1.30	$3.25	
2036	100	Solar		$5.85	$56.46
2036	100	Wind + Battery		$5.85	$363.20
2036	100	Wind + Battery		$5.85	
2038	100	Wind + Battery		$5.85	

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2042	100	Solar		$3.25	
2042	100	Solar		$3.25	

Portfolio 4 (FLEX Shafer Replacement) – Reliability Analysis

PRM, LOLH, and EUE results ("Level 1 Reliability Metrics") are as follows. "Level 2 Reliability Metrics" results can be found in Attachment E.

Planning Reserve Margin

The following table provides the annual PRM resulting from Portfolio 4 – FLEXSR.

Table 84: RAP Planning Reserve Margin, % Annual (Portfolio 4 – FLEXSR)

2025	2026	2027	2028	2029	2030	2031
24%	24%	26%	38%	52%	54%	34%

Table 85: Post-RAP Planning Reserve Margin, % Annual (Portfolio 4 – FLEXSR)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
32%	32%	32%	33%	32%	32%	32%	35%	37%	35%	32%	32%

Loss of Load Hours

The following table provides the annual LoLH resulting from Portfolio 4 – FLEXSR.

Table 86: RAP Loss of Load Probability, Hours (Portfolio 4 – FLEXSR)

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

Table 87: Post-RAP Loss of Load Probability, Hours (Portfolio 4 – FLEXSR)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE resulting from Portfolio 4 – FLEXSR.

Table 88: RAP Expected Unserved Energy, Annual MWh (Portfolio 4 – FLEXSR)

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

Table 89: Post-RAP Loss of Load Probability, Hours (Portfolio 4 – FLEXSR)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

5. No New Gas (NNG)

Assumptions unique to the portfolio are identified in Attachment B-3.

Portfolio 5 (No New Gas) – Expansion Plan, Retirements, System Mix, and Capacity Factors

The expansion plan, DSM selected, plant retirements, system resource mix, and thermal unit capacity factors modeled for the portfolio are shown below.

Table 90: Expansion Plan (Portfolio 5 – NNG)

Year	Project	Technology	Planning Region	Unit Size (MW)	Number of Units[97]	Total MW
2026	ST-0002-5-wco	4hr - Battery	West Colorado	50	1	50
2027	PV-0004-5-wco	Solar	West Colorado	140	1	140
2028	ST-0019-1-eco	Iron Air Battery	East Colorado	100	1	100
	ST-0004-9-eco	4hr - Battery	East Colorado	100	1	100
	ST-0004-8-wco	4hr - Battery	West Colorado	200	1	200
	ST-0004-10-eco	4hr - Battery	East Colorado	100	1	100
	ST-0009-4-nm	4hr - Battery	New Mexico	100	1	100
	PC-0018-1P-nm	Solar / Battery	New Mexico	100	1	100
2029	WI-0013-3-eco	Wind	East Colorado	200	1	200
	PV-0004-4-nm	Solar	New Mexico	100	1	100
	ST-0010-4-eco	4hr - Battery	East Colorado	150	1	150
	ST-0017-1-eco	4hr - Battery	East Colorado	100	1	100
	ST-0018-1-eco	4hr - Battery	East Colorado	50	1	50
2030	PC-0009-2P-eco	Solar / Battery	East Colorado	150	1	150
	ST-0009-3-wco	4hr - Battery	West Colorado	200	1	200
	WI-0013-2-wyo-wne	Wind	Wyoming / W.Neb	200	1	200
2033	-	Wind / Battery	New Mexico	100	2	200
2035	-	Geothermal Storage	West Colorado	20	1	20
2036	-	Wind / Battery	East Colorado	100	2	200
	-	Wind / Battery	New Mexico	100	1	100
2037	-	Wind / Battery	East Colorado	100	1	100
	-	Geothermal[98]	West Colorado	12	1	12
2038	-	Wind / Battery	East Colorado	100	2	200
2042	-	Wind / Battery	East Colorado	100	1	100
	-	Solar	New Mexico	100	1	100
	-	Solar	West Colorado	100	2	200
2043	-	Wind / Battery	East Colorado	100	2	200
	-	Wind / Battery	Wyoming / W.Neb	100	1	100

[97] Each bid is modeled as a single project for purposes of expansion plan selection.
[98] Enhanced Geothermal Baseload (*see* Attachment B-8). Unit size is 25 MW, dispatchable maximum of 12 MW.

The expansion plan also included the following EE levels:

- All plans include applicable Colorado energy efficiency targets in base assumptions.
- 2025: Low New Mexico Energy Efficiency and Low Wyoming Energy Efficiency were selected in the expansion plan of Portfolio 5 – NNG.

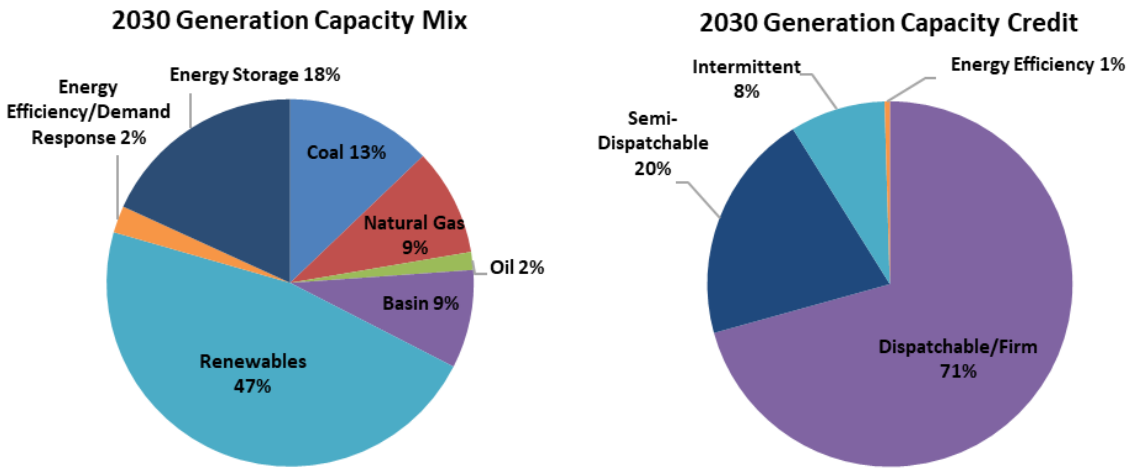
Unit retirements scheduled or selected in the modeling are shown in the following table.[99]

Table 91: Modeled Retirements (Portfolio 5 – NNG)

Location	MW	Technology	Date
Craig 1	427	Coal	12/31/2025
Craig 3	448	Coal	1/1/2028
Craig 2	410	Coal	9/30/2028
Springerville 3	418	Coal	3/1/2031[100]

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

Figure 10: Projected Tri-State System Capacity Mix 2030 (Portfolio 5 – NNG) [101]



[99] 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). Tri-State's share of Craig 1 is 102 MW and Craig 2 is 98 MW. Craig 3 is modeled to retire on the date selected and approved in Phase I of the 2023 ERP.

[100] The New ERA award requires a March 1, 2031 retirement date for SPV 3, given the requirement for USDA to disperse all New ERA funds by September 30, 2031.

[101] "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases.

Figure 11: Projected Tri-State System Energy Mix 2030 (Portfolio 5 – NNG) [102]

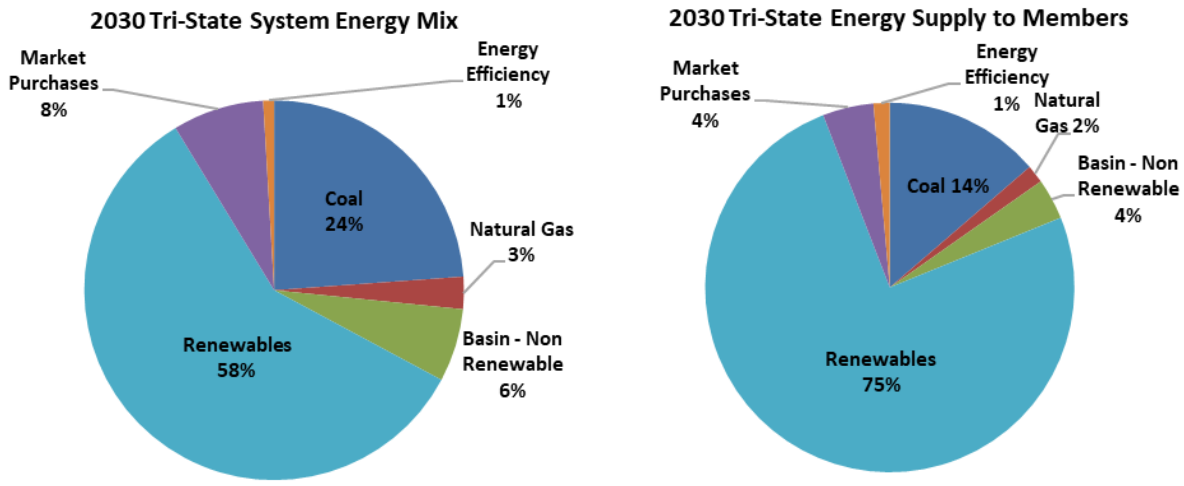


Table 92: Projected Annual Capacity Factors for Thermal Resources (Portfolio 5 – NNG)

Thermal Resource	2025	2026	2027	2028	2029	2030	2031
Craig 1	33%	-	-	-	-	-	-
Craig 2	36%	37%	38%	24%	-	-	-
Craig 3	19%	19%	19%	-	-	-	-
LRS 2	77%	78%	89%	88%	82%	75%	83%
LRS 3	67%	83%	64%	73%	82%	81%	79%
SPV 3	87%	87%	89%	77%	60%	42%	12%
Burlington	0%	0%	0%	0%	0%	0%	0%
Knutson	6%	5%	3%	0%	0%	0%	0%
Limon	4%	3%	0%	0%	0%	0%	0%
Pyramid	7%	1%	1%	0%	0%	0%	0%
Shafer	35%	35%	35%	35%	30%	27%	27%

Portfolio 5 (No New Gas) – Environmental Analysis

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

[102] System Energy Mix reflects sales to Members and non-Members. "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases. Energy for Member Supply is only based on sales to Members and does not include Member-supplied energy in either the supply or sales.

Table 93: Environmental Impact - System Wide (Portfolio 5 – NNG)[103]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2025	12,244,922	5,556	7,270	0.0304	859	3,899,917,881	22,405
2026	11,942,265	6,082	7,499	0.0335	974	4,177,589,447	24,195
2027	11,726,163	5,927	7,347	0.0326	958	4,152,095,618	23,899
2028	9,883,456	5,211	6,132	0.0290	839	3,476,173,634	20,198
2029	8,959,962	4,974	5,831	0.0267	701	2,986,775,243	17,946
2030	7,013,425	4,657	5,500	0.0237	557	2,526,716,133	16,088
2031	5,999,591	4,341	5,298	0.0205	314	1,924,297,995	13,251
2032	5,264,320	4,036	5,000	0.0176	203	1,558,763,516	11,552
2033	5,390,667	4,091	5,043	0.0184	219	1,627,608,477	11,744
2034	5,289,574	4,044	4,975	0.0179	218	1,586,884,489	11,497
2035	5,408,588	4,109	5,066	0.0184	216	1,627,443,211	11,822
2036	5,196,722	3,983	4,903	0.0177	203	1,565,648,310	11,396
2037	5,297,401	4,068	4,958	0.0183	216	1,599,262,492	11,628
2038	5,013,729	3,964	4,754	0.0175	205	1,473,591,656	11,134
2039	5,111,419	4,012	4,817	0.0179	206	1,513,672,212	11,383
2040	4,871,635	3,892	4,696	0.0167	185	1,405,407,473	10,925
2041	4,990,642	3,996	4,805	0.0171	195	1,416,107,699	11,183
2042	4,890,992	3,945	4,778	0.0163	188	1,362,105,080	10,925
2043	4,853,274	3,938	4,726	0.0165	186	1,351,564,503	10,934
Total	**129,348,747**	**84,826**	**103,400**	**0.407**	**7,640**	**41,231,625,068**	**274,106**
Pounds/Gallons per MWh[104]	**916**	**0.60**	**0.73**	**0.000003**	**0.05**	**146**	**2.139**

[103] 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.

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

Table 94: Social Cost of Carbon Nominal Dollars – System Wide (Portfolio 5 – NNG)

Year	Annual Social Cost of Carbon
2025	$1,138,459,687
2026	$1,152,613,302
2027	$1,174,583,082
2028	$1,027,226,838
2029	$965,095,102
2030	$782,717,739
2031	$694,045,278
2032	$631,105,309
2033	$669,577,102
2034	$680,596,397
2035	$720,724,943
2036	$717,042,375
2037	$756,699,323
2038	$741,290,549
2039	$782,081,140
2040	$771,240,407
2041	$813,611,550
2042	$829,766,536
2043	$848,588,980

Table 95: Social Cost of Methane Nominal Dollars – System Wide (Portfolio 5 – NNG)

Year	Annual Social Cost of Methane
2025	$61,742,239
2026	$69,833,909
2027	$72,206,255
2028	$63,846,020
2029	$59,255,701
2030	$55,464,509
2031	$47,830,289
2032	$43,632,908
2033	$46,386,308
2034	$47,461,289
2035	$50,983,048
2036	$51,311,539
2037	$54,636,281
2038	$54,569,169
2039	$58,162,802
2040	$58,177,007
2041	$61,837,927
2042	$63,603,366
2043	$64,997,048

Table 96: GHG Emissions Reduction Percentages, Targets and Forecast (Portfolio 5 – NNG)

Year	Target[105]	Forecast
2025	26%	29%
2026	36%	39%
2027	46%	47%
2030	80%	80%

See Attachment D-5 for detailed GHG emissions calculations for the portfolio.

Portfolio 5 (No New Gas) – Financial Analysis

The PVRR, net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and AFUDC, annual revenue requirement, and NPV by resource for the portfolio are shown below.

Table 97: Total Financial (Portfolio 5 – NNG)

$, Millions	**Portfolio PVRR** (2024 WACC 5.9%)	**SCoC NPV (2.5%)**	**SCoM NPV (2.5%)**	**Portfolio PVRR inclusive of SCoC NPV**	**Portfolio PVRR inclusive of SCoC NPV & SCoM NPV**
	$17,067	$12,429	$838	$29,496	$30,334
Difference to preferred plan (Nominal $)	$624	($499)	($1)	$125	$124

Table 98: Total Financial Generation and Transmission (Portfolio 5 – NNG)

$, Millions	**Expansion Plan CapEx + AFUDC:**	**Difference to preferred plan**
Generation (Nominal $)	$652	$115
Transmission (Nominal $)	$3,008	$1,891

Table 99: Annual Financial (Nominal $) (Portfolio 5 – NNG)

Year	Total Annual Revenue Requirement ($, Millions)
2025	$1,059
2026	$1,049
2027	$1,212
2028	$1,415
2029	$1,423
2030	$1,441

[105] 2020 ERP Phase I Settlement Agreement, at Sections 3.3.4. and 3.3.5 (Proceeding No. 20A-0528E).

Year	Total Annual Revenue Requirement ($, Millions)
2031	$1,523
2032	$1,544
2033	$1,580
2034	$1,555
2035	$1,610
2036	$1,706
2037	$1,739
2038	$1,722
2039	$1,766
2040	$1,789
2041	$1,818
2042	$1,868
2043	$1,954

106 [redacted]

107 [redacted]

108 [redacted]

109 [redacted]

110 [redacted]

[redacted]

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. A majority of the curtailments are in the New Mexico area. There are 400 MW of wind, 490 MW of solar, and 1,275 MW of battery storage (including hybrid batteries) built during the RAP. The amount of curtailment is reduced as more batteries are built.

Table 101: Curtailed Intermittent Energy, Annual MWh (Portfolio 5 – NNG)

	Existing Wind	Existing Solar	Bid Wind	Bid Solar	Total
2025	0	73	0	0	73
2026	0	860	0	0	860
2027	0	759	0	0	759
2028	0	1,707	0	0	1,707
2029	0	62	0	255	317
2030	0	0	0	0	0
2031	0	0	0	0	0
RAP Total	**0**	**3,461**	**0**	**255**	**3,716**

Table 102: Seasonal Intermittent Resource Curtailments, Annual MWh (Portfolio 5 – NNG)

	Winter	Spring	Summer	Fall
2025	0	50	0	23
2026	47	579	57	177
2027	33	672	16	38
2028	117	709	0	881
2029	0	0	176	141
2030	0	0	0	0
2031	0	0	0	0
RAP Total	**197**	**2,010**	**249**	**1,260**

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

Table 103: Estimated PPA Curtailment Costs and Penalties, Real (2024) $ (Portfolio 5 – NNG)

	Wind ($)	Solar ($)
2025	$0	$9,370
2026	$0	$138,416
2027	$0	$105,188
2028	$0	$198,901

2029	$0	$31,189
2030	$0	$0
2031	$0	$0
RAP Total	**$0**	**$483,064**

Portfolio 5 (No New Gas) – Transmission Analysis

Forecasted interconnection and network upgrade expenses resulting from the portfolio are shown in the table below.

Table 104: Transmission Interconnection & Network Upgrade Expenses Real (2024) $ (Portfolio 5 – NNG)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2028	100	ST-0004-9-ECO	$1.50	$5.85	$30.00
2028	100	ST-0004-10-ECO			
2028	100	ST-0019-1-ECO	$1.50	$5.85	
2029	150	ST-0010-4-ECO	$1.50	$5.85	
2029	100	ST-0017-1-ECO	$1.50	$14.62	
2029	50	ST-0018-1-ECO	$1.50	$5.85	
2029	200	WI-0013-3-ECO		$14.62	$81.56
2030	150	PC-0009-2P-ECO		$14.62	$130.00
2036	100	Wind + Battery		$14.62	
2036	100	Wind + Battery		$5.85	
2037	100	Wind + Battery		$6.56	$1,098.06
2038	100	Wind + Battery		$6.56	
2038	100	Wind + Battery		$6.56	
2042	100	Wind + Battery		$6.56	
2043	100	Wind + Battery		$6.56	
2043	100	Wind + Battery		$6.56	
Western Colorado (WCO) Transmission Area					
2026	50	ST-0002-5-WCO	$1.30	$10.94	
2027	140	PV-0004-5-WCO		$3.25	$47.06
2028	200	ST-0004-8-WCO	$1.70	$6.56	
2030	200	ST-0009-3-WCO	$1.50	$5.85	
2035	20	Geothermal Storage	$1.30	$3.25	
2037	12	Geothermal	$1.30	$3.25	
2042	100	Solar		$5.85	
2042	100	Solar		$5.85	
Wyoming (WYO) Transmission Area					
2030	200	WI-0013-2-WYO-WNE		$14.62	$119.24

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2043	100	Wind + Battery		$6.56	
New Mexico (NM) Transmission Area)					
2028	100	PC-0018-1P-NM		$10.94	
2028	100	ST-0009-4-NM	$1.30	$3.25	
2029	100	PV-0004-4-NM		$10.94	$165.62
2033	100	Wind + Battery		$5.85	$363.20
2033	100	Wind + Battery		$5.85	
2036	100	Wind + Battery		$5.85	
2042	100	Solar		$5.85	$56.46

Portfolio 5 (No New Gas) – Reliability Analysis

PRM, LOLH, and EUE results ("Level 1 Reliability Metrics") are as follows. "Level 2 Reliability Metrics" results can be found in Attachment E.

Planning Reserve Margin

The following table provides the annual PRM resulting from Portfolio 5 – NNG.

Table 105: RAP Planning Reserve Margin, % Annual (Portfolio 5 – NNG)

2025	2026	2027	2028	2029	2030	2031
24%	24%	26%	39%	53%	58%	35%

Table 106: Post-RAP Planning Reserve Margin, % Annual (Portfolio 5 – NNG)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
31%	31%	31%	33%	31%	31%	31%	33%	36%	33%	32%	31%

Loss of Load Hours

The following table provides the annual LoLH resulting from Portfolio 5 – NNG.

Table 107: RAP Loss of Load Probability, Hours (Portfolio 5 - NNG)

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

Table 108: Post-RAP Loss of Load Probability, Hours (Portfolio 5 - NNG)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE resulting from Portfolio 5 – NNG.

Table 109: RAP Expected Unserved Energy, Annual MWh (Portfolio 5 – NNG)

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

Table 110: Post-RAP Loss of Load Probability, Hours (Portfolio 5 – NNG)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

6. No New Gas Shafer Replacement (NNGSR)

Assumptions unique to the portfolio are identified in Attachment B-3.

Portfolio 6 (No New Gas Shafer Replacement) – Expansion Plan, Retirements, System Mix, and Capacity Factors

The expansion plan, DSM selected, plant retirements, system resource mix, and thermal unit capacity factors modeled for the portfolio are shown below.

Table 111: Expansion Plan (Portfolio 6 – NNGSR)

Year	Project	Technology	Planning Region	Unit Size (MW)	Number of Units[111]	Total MW
2026	ST-0002-5-wco	4hr - Battery	West Colorado	50	1	50
2027	ST-0004-6-eco	4hr - Battery	East Colorado	150	1	150
2028	ST-0009-4-nm	4hr - Battery	New Mexico	100	1	100
	ST-0004-8-wco	4hr - Battery	West Colorado	200	1	200
	ST-0004-10-eco	4hr - Battery	East Colorado	100	1	100
	ST-0004-9-eco	4hr - Battery	East Colorado	100	1	100
	PV-0006-8-eco	Solar	East Colorado	200	1	200
	PC-0018-1P-nm	Solar / Battery	New Mexico	100	1	100
2029	ST-0017-1-eco	4hr - Battery	East Colorado	100	1	100
	ST-0010-4-eco	4hr - Battery	East Colorado	150	1	150
	WI-0013-3-eco	Wind	East Colorado	200	1	200
2030	WI-0013-2-wyo-wne	Wind	Wyoming/ W. Neb.	200	1	200
	ST-0009-3-wco	4hr - Battery	West Colorado	200	1	200
2033	-	Wind / Battery	East Colorado	100	2	200
2036	-	Geothermal Storage	West Colorado	20	1	20
	-	Wind / Battery	New Mexico	100	3	300
2037	-	Wind / Battery	East Colorado	100	1	100
2038	-	Wind / Battery	East Colorado	100	2	200
2041	-	Solar	West Colorado	100	1	100
2042	-	Solar	West Colorado	100	1	100
	-	Wind	East Colorado	100	2	200
	-	Solar	New Mexico	100	2	200
2043	-	Solar	West Colorado	100	1	100
	-	Wind	Wyoming/ W. Neb.	100	1	100

The expansion plan also included the following EE levels:

- All plans include applicable Colorado energy efficiency targets in base assumptions.
- 2025: Low New Mexico Energy Efficiency and Low Wyoming Energy Efficiency were selected in the expansion plan of Portfolio 6 – NNGSR.

[111] Each bid is modeled as a single project for purposes of expansion plan selection.

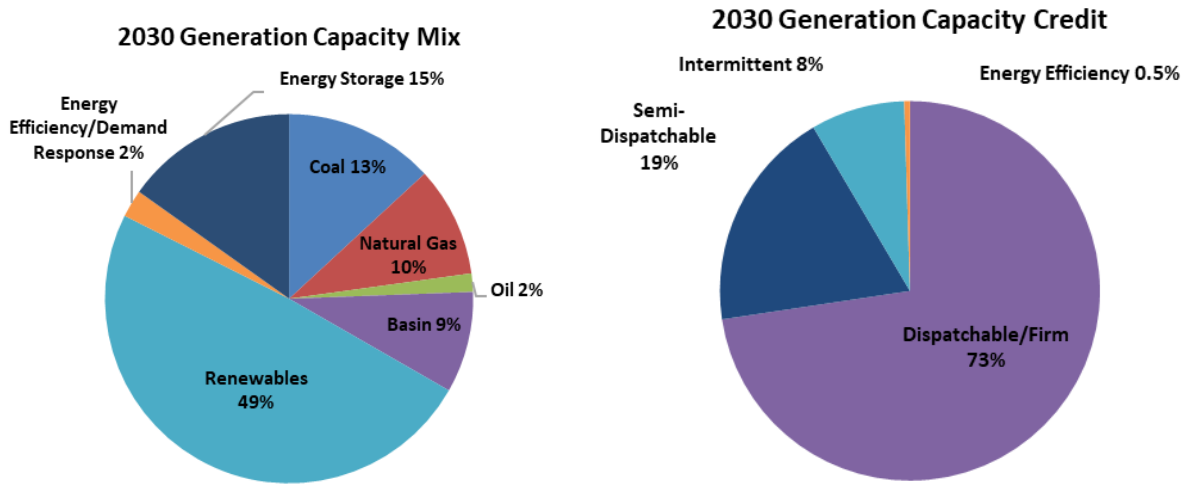
Unit retirements scheduled or selected in the modeling are shown in the following table.[112]

Table 112: Modeled Retirements (Portfolio 6 – NNGSR)

Location	MW	Technology	Date
Craig 1	427	Coal	12/31/2025
Craig 3	448	Coal	1/1/2028
Craig 2	410	Coal	9/30/2028
Springerville 3	418	Coal	3/1/2031[113]

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

Figure 12: Projected Tri-State System Capacity Mix 2030 (Portfolio 6 – NNGSR) [114, 115]



[112] 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). Tri-State's share of Craig 1 is 102 MW and Craig 2 is 98 MW. Craig 3 is modeled to retire on the date selected and approved in Phase I of the 2023 ERP.

[113] The New ERA award requires a March 1, 2031 retirement date for SPV 3, given the requirement for USDA to disperse all New ERA funds by September 30, 2031.

[114] "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases.

[115] Rounding of percentages may lead to values displayed that do not appear to total to 100 percent exactly.

Figure 13: Projected Tri-State System Energy Mix 2030 (Portfolio 6 – NNGSR)[116]

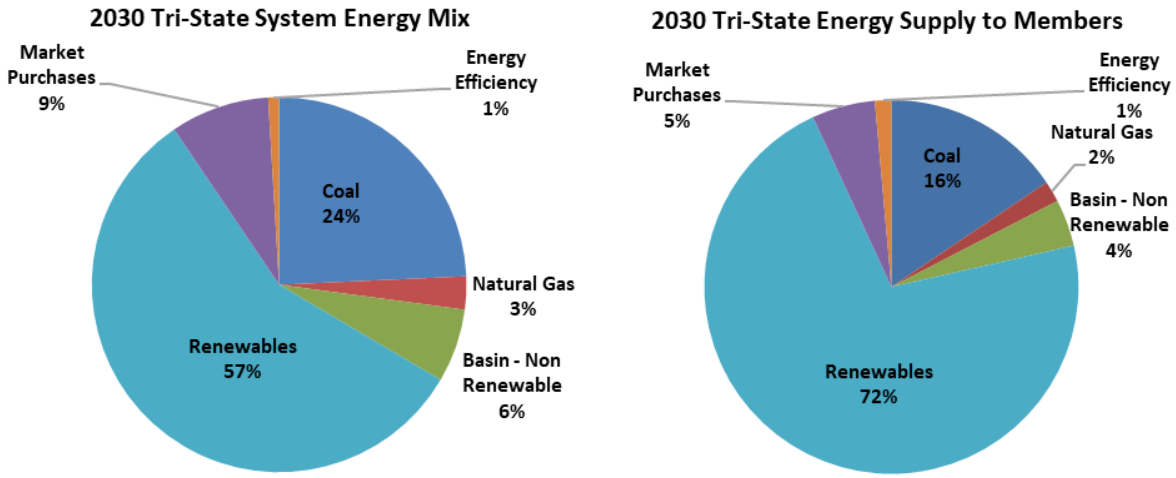


Table 113: Projected Annual Capacity Factors for Thermal Resources (Portfolio 6 – NNGSR)

Thermal Resource	2025	2026	2027	2028	2029	2030	2031
Craig 1	33%	-	-	-	-	-	-
Craig 2	36%	37%	38%	24%	-	-	-
Craig 3	19%	19%	19%	-	-	-	-
LRS 2	77%	78%	89%	88%	82%	75%	83%
LRS 3	67%	83%	53%	70%	81%	81%	78%
SPV 3	87%	87%	89%	75%	65%	42%	12%
Burlington	0%	0%	0%	0%	0%	0%	0%
Knutson	6%	5%	3%	0%	0%	0%	0%
Limon	4%	3%	0%	0%	0%	0%	0%
Pyramid	7%	1%	3%	0%	0%	0%	0%
Shafer	35%	35%	35%	35%	29%	27%	23%

Portfolio 6 (No New Gas Shafer Replacement) – Environmental Analysis

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

[116] System Energy Mix reflects sales to Members and non-Members. "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases. Energy for Member Supply is only based on sales to Members and does not include Member-supplied energy in either the supply or sales.

Table 114: Environmental Impact - System Wide (Portfolio 6 – NNGSR)[117]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2025	12,244,922	5,556	7,270	0.0304	859	3,899,917,881	22,405
2026	11,946,206	6,083	7,503	0.0335	974	4,178,260,972	24,199
2027	11,570,025	5,771	7,228	0.0311	936	4,046,421,059	23,332
2028	9,814,861	5,160	6,100	0.0283	815	3,401,715,998	19,898
2029	9,111,475	5,027	5,871	0.0272	737	3,073,163,383	18,316
2030	7,050,577	4,679	5,541	0.0238	558	2,532,813,977	16,162
2031	6,019,427	4,364	5,342	0.0204	312	1,913,037,441	13,312
2032	5,363,900	4,052	5,095	0.0176	206	1,604,501,764	11,641
2033	5,520,168	4,151	5,180	0.0184	223	1,661,803,495	11,946
2034	5,414,719	4,107	5,110	0.0180	221	1,615,591,795	11,712
2035	5,560,472	4,185	5,220	0.0186	221	1,665,887,399	12,084
2036	5,239,029	3,999	4,961	0.0176	203	1,573,524,559	11,453
2037	5,344,620	4,099	5,025	0.0182	215	1,590,771,662	11,726
2038	5,084,182	4,014	4,837	0.0175	205	1,470,546,688	11,293
2039	5,164,519	4,055	4,885	0.0180	205	1,504,603,982	11,518
2040	4,894,020	3,929	4,744	0.0167	183	1,379,333,329	11,025
2041	5,034,909	4,021	4,859	0.0171	196	1,413,662,279	11,266
2042	4,876,519	3,942	4,765	0.0163	188	1,347,184,439	10,913
2043	4,887,594	3,957	4,771	0.0165	186	1,347,404,577	10,997
Total	**130,142,142**	**85,151**	**104,306**	**0.405**	**7,642**	**41,220,146,679**	**275,198**
Pounds/Gallons per MWh[118]	**922**	**0.60**	**0.74**	**0.000003**	**0.05**	**146**	**2.148**

[117] 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.
[118] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 115: Social Cost of Carbon Nominal Dollars – System Wide (Portfolio 6 – NNGSR)

Year	Annual Social Cost of Carbon
2025	$1,138,459,687
2026	$1,152,993,624
2027	$1,158,943,111
2028	$1,020,097,553
2029	$981,414,787
2030	$786,863,978
2031	$696,339,955
2032	$643,043,287
2033	$685,662,450
2034	$696,698,482
2035	$740,964,313
2036	$722,879,934
2037	$763,444,178
2038	$751,707,224
2039	$790,205,684
2040	$774,784,316
2041	$820,828,229
2042	$827,311,151
2043	$854,589,790

Table 116: Social Cost of Methane Nominal Dollars – System Wide (Portfolio 6 – NNGSR)

Year	Annual Social Cost of Methane
2025	$61,742,239
2026	$69,847,236
2027	$70,492,985
2028	$62,895,824
2029	$60,478,517
2030	$55,718,807
2031	$48,051,268
2032	$43,969,826
2033	$47,182,943
2034	$48,348,612
2035	$52,112,380
2036	$51,565,121
2037	$55,096,401
2038	$55,345,788
2039	$58,855,626
2040	$58,711,741
2041	$62,293,992
2042	$63,533,142
2043	$65,368,924

Table 117: GHG Emissions Reduction Percentages, Targets and Forecast (Portfolio 6 – NNGSR)

Year	Target[119]	Forecast
2025	26%	29%
2026	36%	39%
2027	46%	47%
2030	80%	80%

See Attachment D-6 for detailed GHG emissions calculations for the portfolio.

Portfolio 6 (No New Gas Shafer Replacement) – Financial Analysis

The PVRR, net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and AFUDC, annual revenue requirement, and NPV by resource for the portfolio are shown below.

Table 118: Total Financial (Portfolio 6 – NNGSR)

$, Millions	Portfolio PVRR (2024 WACC 5.9%)	SCoC NPV (2.5%)	SCoM NPV (2.5%)	Portfolio PVRR inclusive of SCoC NPV	Portfolio PVRR inclusive of SCoC NPV & SCoM NPV
	$16,531	$12,509	$842	$29,039	$29,881
Difference to preferred plan (Nominal $)	$88	($420)	$3	($332)	($329)

Table 119: Total Financial Generation and Transmission (Portfolio 6 – NNGSR)

$, Millions	Expansion Plan CapEx + AFUDC:	Difference to preferred plan
Generation (Nominal $)	$265	($272)
Transmission (Nominal $)	$1,100	($16)

Table 120: Annual Financial (Nominal $) (Portfolio 6 – NNGSR)

Year	Total Annual Revenue Requirement ($, Millions)
2025	$1,059
2026	$1,051
2027	$1,236
2028	$1,317
2029	$1,335
2030	$1,358

[119] 2020 ERP Phase I Settlement Agreement, at Sections 3.3.4. and 3.3.5 (Proceeding No. 20A-0528E).

Year	Total Annual Revenue Requirement ($, Millions)
2031	$1,447
2032	$1,480
2033	$1,507
2034	$ 1,526
2035	$1,523
2036	$1,610
2037	$1,618
2038	$1,685
2039	$1,711
2040	$1,741
2041	$1,786
2042	$1,839
2043	$1,899

120 [redacted]

121 [redacted]

122 [redacted]

123 [redacted]

124 [redacted]

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. A majority of the curtailments are in the New Mexico area. There are 400 MW of wind, 300 MW of solar, and 1,200 MW of battery storage (including hybrid batteries) built during the RAP. The amount of curtailment is reduced as more batteries are built.

Table 122: Curtailed Intermittent Energy, Annual MWh (Portfolio 6 – NNGSR)

	Existing Wind	Existing Solar	Bid Wind	Bid Solar	Total
2025	0	101	0	0	101
2026	0	1,205	0	0	1,205
2027	0	1,233	0	0	1,233
2028	0	285	0	13	298
2029	0	5	0	0	5
2030	0	0	0	0	0
2031	0	0	0	0	0
RAP Total	**0**	**2,829**	**0**	**13**	**2,842**

Table 123: Seasonal Intermittent Resource Curtailments, Annual MWh (Portfolio 6 – NNGSR)

	Winter	Spring	Summer	Fall
2025	0	60	0	41
2026	72	825	98	210
2027	36	938	54	205
2028	182	57	0	59
2029	0	0	0	5
2030	0	0	0	0
2031	0	0	0	0
RAP Total	**290**	**1,880**	**152**	**520**

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

Table 124: Estimated PPA Curtailment Costs and Penalties, Real (2024) $ (Portfolio 6 – NNGSR)

	Wind ($)	Solar ($)
2025	$0	$13,166
2026	$0	$166,014
2027	$0	$171,286
2028	$0	$42,920
2029	$0	$798
2030	$0	$0
2031	$0	$0
RAP Total	**$0**	**$394,184**

Portfolio 6 (No New Gas Shafer Replacement) – Transmission Analysis

Forecasted interconnection and network upgrade expenses resulting from the portfolio are shown in the table below.

As described in the Executive Summary Portfolio Analysis section above and in Attachment G, Tri-State analyzed Portfolio 6 – NNGSR bid selections for transmission interconnection and upgrade cost considerations and the potential to utilize surplus interconnection, and implemented transmission modeling optimizations, to ensure that the benefits of this approach were evaluated under both a new gas and no new gas portfolio. As a result of this analysis, this portfolio avoids significant transmission upgrade costs during the RAP similar to the preferred portfolio, but has a higher PVRR.

Table 125: Transmission Interconnection & Network Upgrade Expenses Real (2024) $ (Portfolio 6 – NNGSR)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2026	150	ST-0004-6-ECO			
2028	200	PV-0006-8-ECO		$5.85	
2028	100	ST-0004-10-ECO			
2028	100	ST-0004-9-ECO			$30.00
2029	150	ST-0010-4-ECO	$1.50	$5.85	
2029	100	ST-0017-1-ECO	$1.50	$14.62	
2029	200	WI-0013-3-ECO		$14.62	
2033	100	Wind		$5.85	$81.56
2033	100	Wind		$5.85	
2037	100	Wind + Battery		$5.85	
2038	100	Wind + Battery		$5.85	$148.74
2038	100	Wind + Battery		$5.85	
2042	100	Wind		$14.62	
2042	100	Wind		$5.85	

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Western Colorado (WCO) Transmission Area					
2026	50	ST-0002-5-WCO	$1.30	$10.94	
2028	200	ST-0004-8-WCO	$1.70	$6.56	
2030	200	ST-0009-3-WCO	$1.50	$5.85	
2036	20	Geothermal Storage	$1.30	$3.25	
2041	100	Solar		$5.85	
2042	100	Solar		$6.56	
2043	100	Solar		$6.56	
Wyoming (WYO) Transmission Area					
2030	200	WI-0013-2-WYO-WNE		$14.62	
2043	100	Wind		$6.56	
New Mexico (NM) Transmission Area)					
2028	100	PC-0018-1P-NM		$10.94	
2028	100	ST-0009-4-NM	$1.30	$3.25	
2036	100	Wind + Battery		$5.85	$363.20
2036	100	Wind + Battery		$5.85	
2036	100	Wind + Battery		$5.85	
2042	100	Solar		$5.85	
2042	100	Solar		$5.85	

Portfolio 6 (No New Gas Shafer Replacement) – Reliability Analysis

PRM, LOLH, and EUE results are ("Level 1 Reliability Metrics") as follows. "Level 2 Reliability Metrics" results can be found in Attachment E.

Planning Reserve Margin

The following table provides the annual PRM resulting from Portfolio 6 – NNGSR.

Table 126: RAP Planning Reserve Margin, % Annual (Portfolio 6 – NNGSR)

2025	2026	2027	2028	2029	2030	2031
24%	24%	26%	42%	51%	53%	33%

Table 127: Post-RAP Planning Reserve Margin, % Annual (Portfolio 6 – NNGSR)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
31%	31%	31%	32%	31%	31%	31%	33%	36%	34%	31%	31%

Loss of Load Hours

The following table provides the annual LoLH resulting from Portfolio 6 – NNGSR.

Table 128: RAP Loss of Load Probability, Hours (Portfolio 6 – NNGSR)

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

Table 129: Post-RAP Loss of Load Probability, Hours (Portfolio 6 – NNGSR)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE resulting from Portfolio 6 – NNGSR.

Table 130: RAP Expected Unserved Energy, Annual MWh (Portfolio 6 – NNGSR)

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

Table 131: Post-RAP Loss of Load Probability, Hours (Portfolio 6 – NNGSR)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

7. Renewable Back-up Bid Pool (BkRE)

The approach to modeling back-up bid pools is described in Attachment B-3 and in the Phase II Portfolio Analysis section in the Executive Summary. The expansion plan selected the following renewable bids as the most economic for the back-up pool.

Table 132: Renewable Back-up Bid Pool

Year	Project	Technology	Planning Region	Unit Size (MW)	Number of Units[125]	Total MW
2027	PC-0004-1P-nm	Solar / Battery	New Mexico	90	1	90
	PV-0004-5-wco	Solar	West Colorado	140	1	140
2029	WI-0016-1-eco	Wind	East Colorado	297	1	297
	PC-0021-1P-wco	Solar / Battery	West Colorado	125	1	125
	PV-0004-4-nm	Solar	New Mexico	100	1	100
	WI-0005-3-eco	Wind	East Colorado	150	1	150

[125] Each bid is modeled as a single project for purposes of expansion plan selection.

8. Standalone Storage Back-up Bid Pool (BkST)

The approach to modeling back-up bid pools is described in Attachment B-3 and in the Phase II Portfolio Analysis section in the Executive Summary. The expansion plan selected the following standalone storage bids as the most economic for the back-up pool.

Table 133: Standalone Storage Back-up Bid Pool

Year	Project	Technology	Planning Region	Unit Size (MW)	Number of Units[126]	Total MW
2027	ST-0002-6-wco	4hr - Battery	West Colorado	100	1	100
2028	ST-0006-3-nm	4hr - Battery	New Mexico	100	1	100
2029	ST-0018-1-eco	4hr - Battery	East Colorado	50	1	50
	ST-0010-4-eco	4hr - Battery	East Colorado	150	1	150
	ST-0017-1-eco	4hr - Battery	East Colorado	100	1	100

[126] Each bid is modeled as a single project for purposes of expansion plan selection.

9. Gas Plant Back-up Bids (BkNG)

The approach to back-up bid pools is described in Attachment B-3 and in the Phase II Portfolio Analysis section in the Executive Summary. Only one alternative gas plant bid is available during the RAP, therefore Tri-State did not conduct further modeling to determine a gas plant back-up bid pool.

Table 134: Gas Plant Back-up Bid Pool

Year	Project	Technology	Planning Region	Unit Size (MW)	Number of Units[127]	Total MW
2030	GG-0005-1-wco	Combustion Turbine	West Colorado	45.325	4	181.3

[127] Each bid is modeled as a single project for purposes of expansion plan selection.

Comparative Analysis

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

Environmental Analysis

The following tables identify each portfolio's system-wide forecasted CO_2 and CH_4 emissions in 2026 and 2031.

Figure 14: Comparison of Forecasted System CO_2 Emissions in 2026 and 2031, by Portfolio

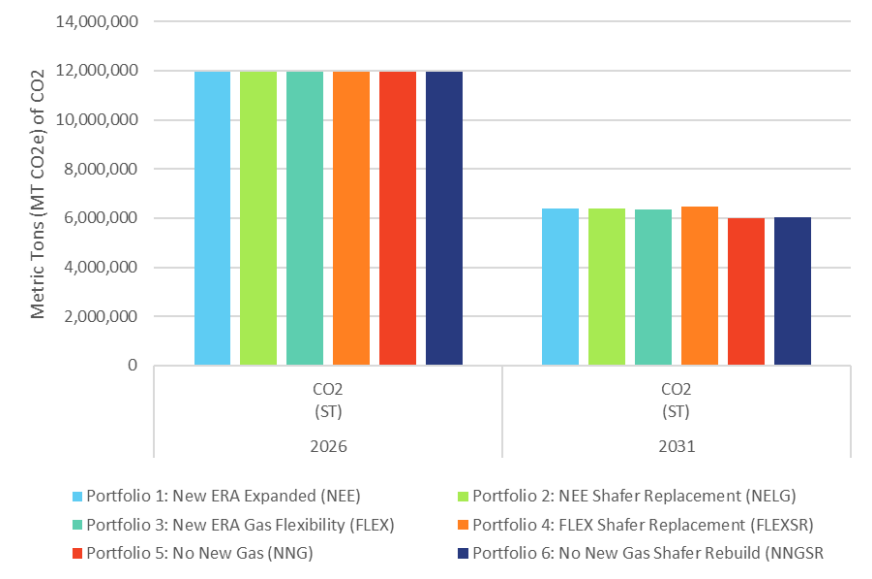
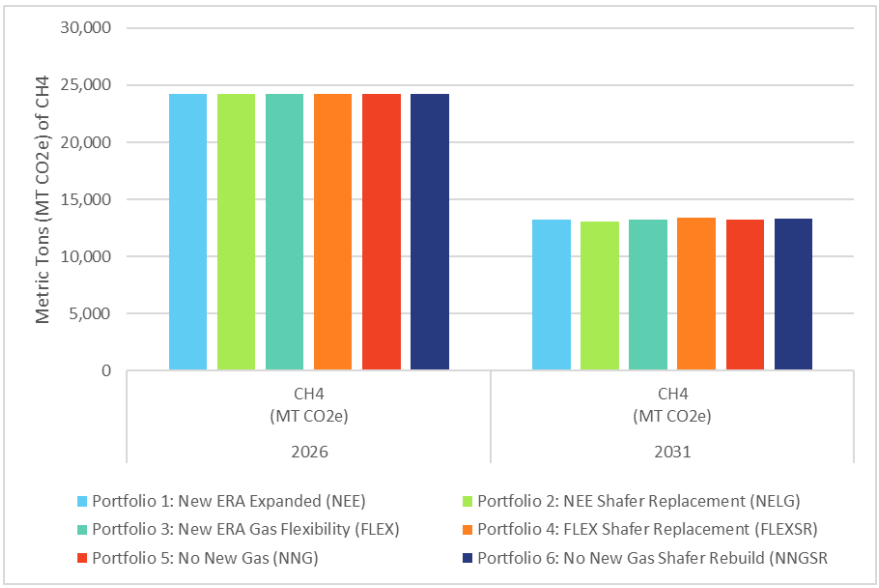


Figure 15: Comparison of Forecasted System CH_4 Emissions in 2026 and 2031, by Portfolio



The following table identifies each portfolio's forecasted achievements toward Colorado GHG reduction targets. Modeling indicates all Phase II portfolios are able to achieve the Colorado GHG reduction

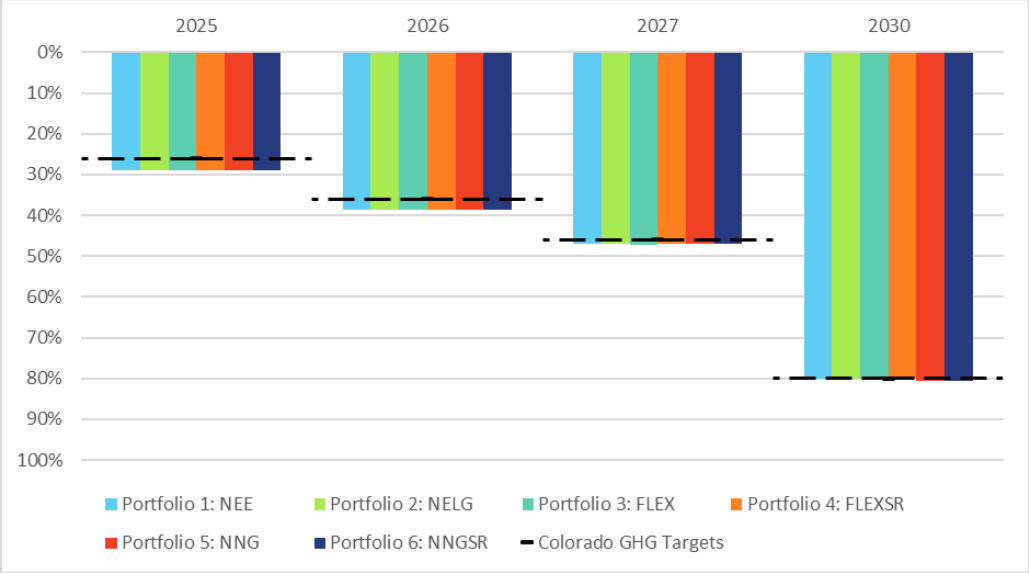
targets in 2025,[128] 2026, 2027, and 2030. Forecasted emissions reductions in 2030 in Phase II meet the minimum statutory requirement, and do not vary substantially across portfolios. This is driven in part by the model seeking a least-cost expansion plan, based on actual bid pricing (versus generic resources in Phase I), as well as new APCD guidance issued in December 2024 on the approach to forecasting market emission rates. In Phase II, emission rates for market purchases and sales are reflective of expectations that the residual mix of supply from the market is anticipated to be primarily thermal energy.

Additional discussion of Tri-State's consideration of the environmental results of the portfolio analyses can be found in the Portfolio Analysis section of the Executive Summary; and discussion of SCoC and SCoM in the Financial Analysis section below.

Table 135: Comparison of Forecasted Colorado GHG Reduction by Portfolio in GHG Target Years

	2025	2026	2027	2030
Portfolio 1: New ERA Expanded	29%	39%	47%	80%
Portfolio 2: New ERA Limited Gas	29%	39%	47%	80%
Portfolio 3: New ERA Gas Flexibility (FLEX)	29%	39%	47%	80%
Portfolio 4: FLEX Shafer Replacement	29%	39%	47%	80%
Portfolio 5: No New Gas (NNG)	29%	39%	47%	80%
Portfolio 6: NNG Shafer Replacement	29%	39%	47%	80%

Figure 16: Comparison of Portfolio Achievements Toward Colorado GHG Reduction Targets



[128] Trending at the end of Q1-2025 is positive toward achievement of Tri-State's first GHG reduction target.

Figure 17: Comparison of Colorado CO2e

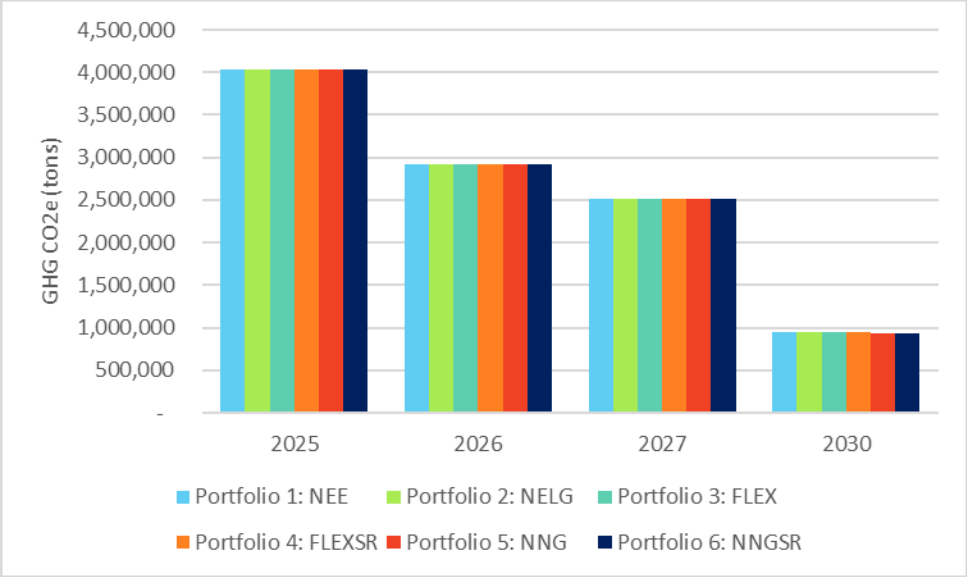


Figure 18: Comparison of SCoC During the RAP

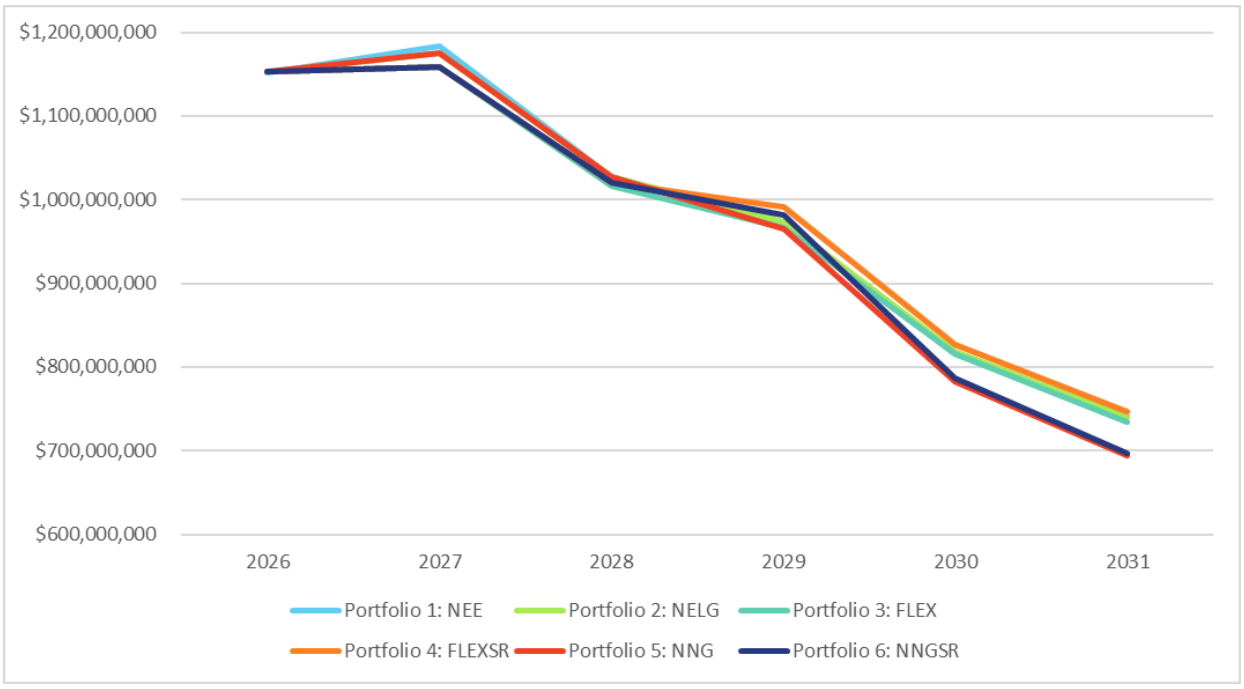
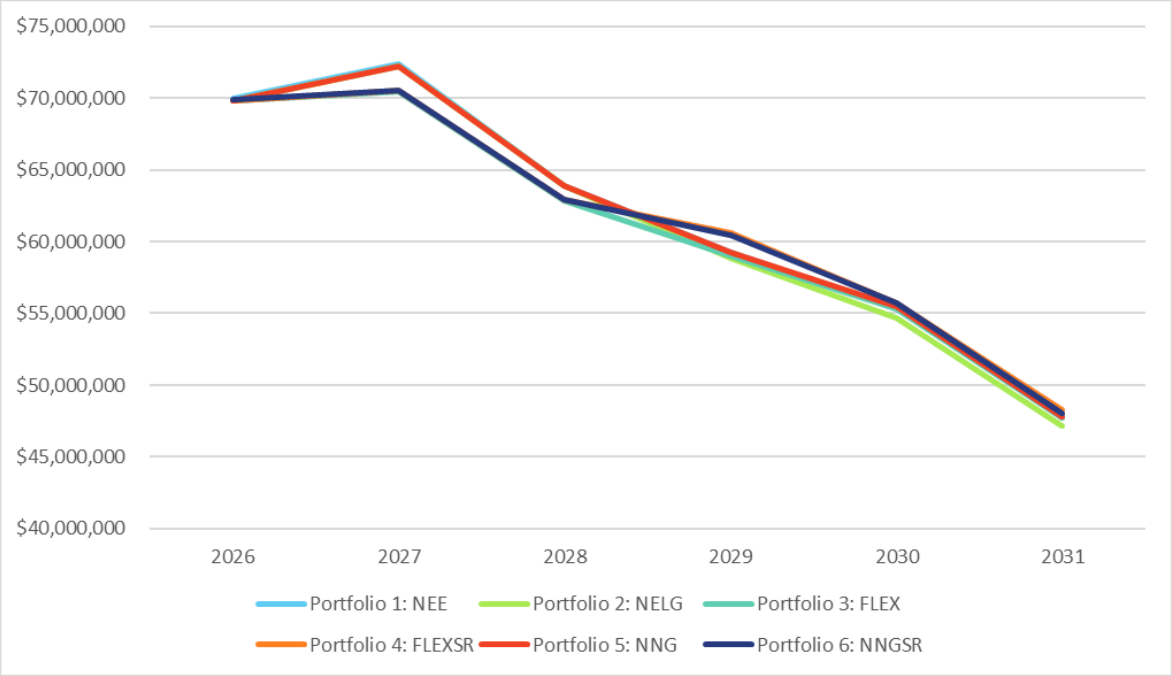


Figure 19: Comparison of SCoM During the RAP



Financial Analysis

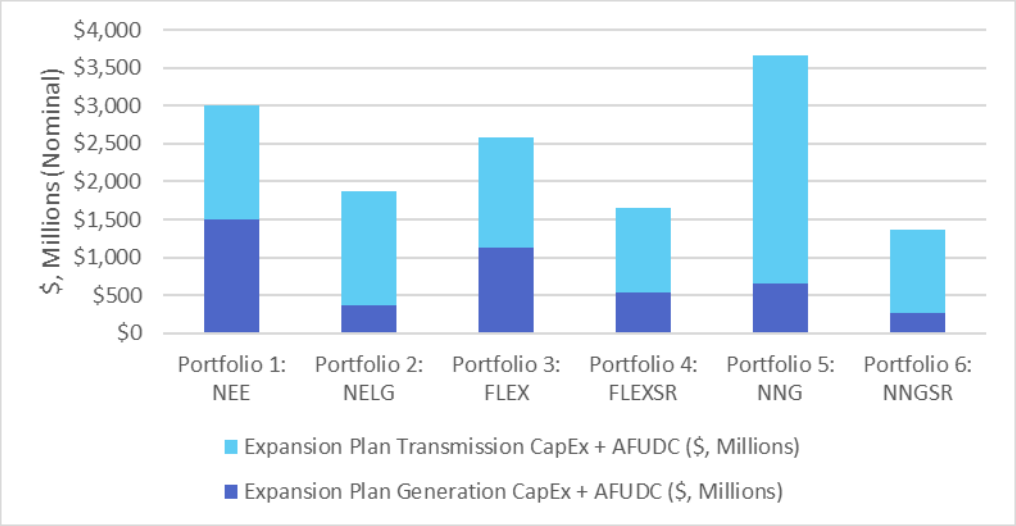
The following table compares total financial results for each portfolio, both with and without the SCoC and SCoM. Portfolio 4 – FLEXSR is the lowest cost plan on a PVRR basis, requiring fewer new resource acquisitions than other portfolios while achieving comparable emissions reductions and reliability results—an important value for Tri-State's Members. Further discussion of the financial benefits achieved with Portfolio 4 – FLEXSR bid selections is identified in Attachment G.

Table 136: Comparison of PVRR

	PVRR ($, Millions)	**PVRR w/SCoC and SCoM ($, Millions)**
Portfolio 1: New ERA Expanded	$16,836	$30,584
Portfolio 2: New ERA Limited Gas	$16,841	$30,524
Portfolio 3: New ERA Gas Flexibility	$16,761	$30,488
Portfolio 4: FLEX Shafer Replacement	$16,443	$30,210
Portfolio 5: No New Gas	$17,067	$30,334
Portfolio 6: No New Gas Shafer Replacement	$16,531	$29,881

The following figure compares capital expenditures and MW additions by portfolio.

Figure 20: Comparison of Generation and Transmission CapEx (Nominal $) During the RPP



As shown in below, the MW level and type of resource additions selected in Portfolios 2 and 3 are relatively similar. Renewable MWs were relatively consistent across all portfolios, except for Portfolio 3 which selected more wind and less solar. Portfolios 1-4 selected a gas plant bid and had a similar amount of storage MW selections, whereas Portfolios 5 and 6, which did not allow new gas, required a considerably larger amount of storage resource additions. Portfolio 4, the preferred portfolio, requires the least amount of resource additions with less transmission capital expenditures. Portfolio 5 requires more MW resource additions than other portfolios in order to maintain system reliability without the addition of a dispatchable gas resource, but at a higher PVRR than any other portfolio. Tri-State is concerned about the potential risk in overreliance on 4-hour batteries suggested by the resource additions in Portfolios 5 and 6; Tri-State has not yet deployed any batteries on its system and storage technologies, including longer duration storage options, are anticipated to make advancements in the coming years.

Table 137: Comparison of MW Additions by Portfolio, by Technology over the RAP

MW	Portfolio 1: NEE	Portfolio 2: NELG	Portfolio 3: FLEX	Portfolio 4: FLEXSR	Portfolio 5: NNG	Portfolio 6: NNGSR
Wind	400	400	497	400	400	400
Solar	240	240	100	200	240	200
Standalone Storage -Short Duration	450	650	650	600	1,050	1,150
Standalone Storage - Long Duration	100	0	0	0	100	0
Gas	307	307	307	307	0	0
Solar Hybrid	250	250	250	100	250	100
RAP Total	**1,747**	**1,847**	**1,804**	**1,607**	**2,040**	**1,850**
Solar Hybrid – Battery Storage Component	125	125	125	50	125	50
RAP Total w/Hybrid Storage	**1,872**	**1,972**	**1,929**	**1,657**	**2,165**	**1,900**

Table 138: Comparison of Number of Bids by Portfolio, by Technology over the RAP

	Portfolio 1: NEE	Portfolio 2: NELG	Portfolio 3: FLEX	Portfolio 4: FLEXSR	Portfolio 5: NNG	Portfolio 6: NNGSR
Wind	2	2	2	2	2	2
Solar	2	2	1	1	2	1
Standalone Storage -Short Duration	4	6	6	5	9	9
Standalone Storage - Long Duration	1	0	0	0	1	0
Gas	1	1	1	1	0	0
Solar Hybrid	2	2	2	1	2	1
RAP Total	**12**	**13**	**12**	**10**	**16**	**13**

Table 139 below identifies the percentage of Tri-State's system energy and energy supplied to Members that is forecasted to be renewable, for each portfolio in 2030. Table 140 identifies the percentage of generation capacity mix that is renewable for each portfolio in 2030. Table 141 identifies the percentage of generation capacity credit that is dispatchable/firm for each portfolio in 2030. While the preferred portfolio yields a slightly lower percentage of renewables on an energy supply basis, on a generation capacity supply basis the preferred portfolio has a similar percentage of renewables in its mix as the other portfolios. Importantly, all portfolios achieve Tri-State's aspirational target of having 70 percent clean supply to Members in 2030, but the preferred portfolio does so at the least cost.

Table 139: Comparison of Renewables' Contribution to System and Member Supply in 2030, by Portfolio

	2030 System Energy Mix	2030 Tri-State Energy Supply to Members
	% Renewables	
Portfolio 1: NEE	57%	75%
Portfolio 2: NELG	57%	75%
Portfolio 3: FLEX	57%	75%
Portfolio 4: FLEXSR	55%	71%
Portfolio 5: NNG	58%	75%
Portfolio 6: NNGSR	57%	72%

Table 140: Comparison of Renewables' Contribution to Generation Capacity in 2030, by Portfolio

	2030 Generation Capacity Mix
	% Renewables
Portfolio 1: NEE	49%
Portfolio 2: NELG	48%
Portfolio 3: FLEX	48%
Portfolio 4: FLEXSR	48%
Portfolio 5: NNG	47%
Portfolio 6: NNGSR	49%

Table 141: Comparison of Dispatchable/Firm Contribution to the System Mix in 2030, by Portfolio

	2030 Generation Capacity Credit
	% Dispatchable/Firm
Portfolio 1: NEE	78%
Portfolio 2: NELG	76%
Portfolio 3: FLEX	77%
Portfolio 4: FLEXSR	80%
Portfolio 5: NNG	71%
Portfolio 6: NNGSR	73%

Curtailments

The following table identifies the annual total curtailment costs (PPA pricing, penalties, and taxes) estimated to result from the modeled curtailments, by resource type. None of the portfolios result in wind PPA curtailment costs. Significant solar curtailment costs in all portfolios reflects the inherent challenges in integrating a large amount of intermittent resources into the system in a short timespan. More intermittent resources leads to more curtailment, but storage additions mitigate curtailments.

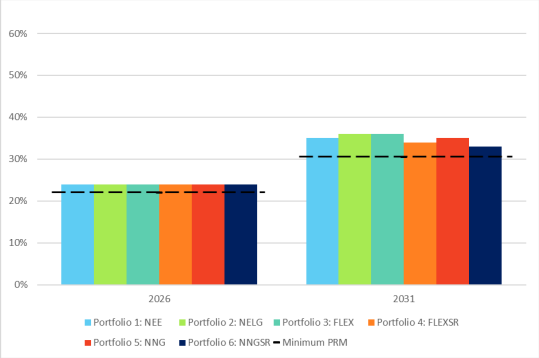
Table 142: Comparison of Solar Curtailment Costs by Portfolio, Real (2024) $

	Portfolio 1: NEE	Portfolio 2: NELG	Portfolio 3: FLEX	Portfolio 4: FLEXSR	Portfolio 5: NNG	Portfolio 6: NNGSR
2026	$145,247	$156,979	$125,261	$152,487	$138,416	$166,014
2027	$224,019	$114,621	$151,371	$193,537	$105,188	$171,286
2028	$214,350	$143,388	$107,958	$90,037	$198,901	$42,920
2029	$18,138	$56,325	$18,876	$51,807	$31,189	$798
2030	$0	$0	$0	$0	$0	$0
2031	$0	$0	$0	$0	$0	$0
RAP Total	**$601,754**	**$471,313**	**$403,466**	**$487,868**	**$473,694**	**$381,018**

Reliability Analysis

PRMs are relatively consistent across all portfolios. Increasing PRMs after 2026 occur as a result of the large amount of intermittent resource additions during the RAP.

Figure 21: Comparison of PRMs During the RAP



Each of the portfolios met Level 1 and 2 Reliability Metrics. The preferred portfolio (FLEXSR) achieves reliability in the most cost-effective manner.

NNG and NNGSR portfolios rely on an extensive amount of storage resources to maintain reliability, creating a heavy reliance on a semi-dispatchable technology during the energy transition—a technology that Tri-State has not yet deployed. Storage technology may evolve and improve in both cost and performance in the coming years, thus Tri-State and its Members seek to make investment during this RAP in a manner that result in a balanced and diversified technology mix, at the least cost.

Conclusion

This Implementation Report provides extensive detail on the multiple portfolios modeled. Tri-State believes this analysis builds a clear record that supports approval of Tri-State's preferred portfolio, FLEXSR, including as a result of the analyses provided in Attachments G and H. Tri-State requests the Commission approve Tri-State's preferred portfolio, Portfolio 4 – FLEXSR, as the final cost-effective resource plan for Phase II of the 2023 ERP, pursuant to Rule 3605(h)(II).

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-88:
Tri-State 2023 ERP Modeling Assumptions

Colorado PUC E-Filings System

Modeling Assumptions

The following table and discussion identify the modeling assumptions to be used in Phase I of Tri-State's 2023 ERP.

Table 1: Modeling Assumptions

Category	Assumption	Description of Modeling Input
Financial	Electric and Gas Forward Curves, and Transport Cost	• Horizon[1] 2023 Spring Forecasts for electric and gas forward curves • Transport adders based on interstate gas provider rates
	Coal Forward Curve	March 2023 forecast in real and nominal dollars
	Capital Expenditures and Fixed O&M	Tri-State 2023 O&M Budget and 10-Year Capital Plan
	Variable O&M	2023 O&M Budget of thermal resource VOMs
	Annual Inflation Forecast	Annual inflation projections as of February 2023
	Depreciation Costs and Schedules	2023 Depreciation Study will inform the rate that existing assets are depreciated in the financial modeling
	Renewable and Storage Generic Resource Prices – PPAs and Build Transfers	Updated based on 2020 ERP Phase II bid responses, IRA impacts, latest PTC/ITC, and $1/MWh Wyoming Wind Tax
	Gas Generic Resource Build Prices	B&V reviewed and refreshed generic gas pricing
	Innovative Technology Pricing	Newly added resource types and modeling assumptions (e.g., Small Modular Reactors, Hydrogen, Molten Salt Long-Term Storage, Iron Air Storage, Geothermal, etc.)
	Resource Integration Adder (Ancillary Service Costs)	Generic resources (as applicable) as follows: WCO, WY-WNE, and ECO updated with WACM; and NM updated with PNM
	Discount Rate / Weighted Average Cost of Capital (WACC)	Updated to 4.12%
	LRS 2 & 3 Retirement Cost Profile	Reflects continuation of fixed and capex costs through useful life
	Springerville Unit 3 (SPV 3) Retirement Cost Profile	Financing and equity partner penalties applicable if unit retired early
	Craig Station Decommissioning Cost	Reflects third-party cost estimate, and Tri-State's share of the cost
	Book Life for Generic Li-Ion Batteries, Renewables, and Gas	Use of book life assumptions for each generic resource and useful life for each existing resource
	Third Party Transmission	• Reflects network and firm point to point transmission available between planning regions

[1] Horizons Energy is a data and analytics consulting company providing market price forecasts for the energy industry. See: https://www.horizons-energy.com/market-price-forecasting/.

		• Added ability to procure additional transmission between planning regions as available at a cost.
Operational	CRSP Hydro Forecast	Forecasted capacity from CRSP hydro contract reflects continued reduction through the planning period due to drought.
	Load Forecast	Forecast as of Summer 2022 with United Power and Northwest Rural Public Power District exiting May 1, 2024 and Mountain Parks exiting February 1, 2025
		Partial Requirements Contracts for May 2021 and May 2022 Open Seasons (excluding Mountain Parks) included as applicable load reductions beginning January 2026
	Beneficial Electrification	Achievable-Moderate level from 2023 BE Potential Study[2]
	Distributed Generation Forecast	Forecast of Member DG as of March 2023 with appropriate Member exits (United Power and Mountain Parks)
	Constraints	Updated constraints on new resource builds and transmission interconnection
	Level I & II Reliability Metrics	Scenarios were modeled to meet minimum Level I and II reliability requirements
	Thermal Build Constraint	No thermal builds allowed before 2028
	Gas Retirement Constraint	No gas resources allowed to retire
	Coal Unit Uptime	Uptime minimum 12 hours
	Coal Unit Downtime	Downtime minimum 8 hours
	Craig 3 Modeling	Craig 3 is modeled in ECON mode
	Craig Unit Retirements	• Craig Units 1 and 2 retirements are modeled to occur on the announced dates. • Craig Unit 3 is modeled to retire between 2028-2029.[3]
	Tri-State Exit MBPP[4]	Allowed in modeling beginning January 1, 2027
	SPV 3 Retirement	Allowed in modeling beginning January 1, 2037
	SPV 3 Max Capacity	SPV 3 rerated to 419 MW per 2022 testing
	Effective Load Carrying Capability (ELCC)	Based on third-party study
	Scheduled Outages	Planned outage schedules updated for all thermal units
	Forced Outage Factors	Applied unit-specific rates based on 5 years of historical data from GADs. Updated forced outage method in dispatch runs to have random outage days instead of a derate.
	Modeling of Market Sales and Purchases Depths	• Market sales and purchases hourly depth updated. • Values are reflective of:

[2] Attachment G-3 of the ERP Report (LKT-1)
[3] Also see Attachment B-3 of the ERP Report (LKT-1) for unique scenario assumptions.
[4] Tri-State has no current plans to exit the Missouri Basin Power Project ("MBPP") – see written information regarding this modeling assumption below.

		○ Member exits ○ Moving WACM load (WY/WNE, WCO and a portion of ECO) to SPP RTO in April 2026 ○ Remainder of ECO load and all NM load to RTO by 2030.
	Modeling of Term Sales	Known and anticipated term sales opportunities are reflected in modeling
	Modeling of Proxy Sales	Anticipated capacity and energy sales opportunities are reflected in modeling
	Generic Resource Availability	The model will be able to select generic resources starting in as soon as 2026, depending on lead time of each technology
	PPA and Contract Information	Updated latest known COD and reflect any updated terms
	SRP Contract	Model based on market optimization
	System Loss Factor	NM region losses are financial; updated ECO, WCO and WY/NE to 3.5%
Demand-Side Management	Demand Response	DR Target (4% of load) modeled for ECO and WCO; Tri-State DR Program Levels selectable for NM and WY
	Energy Efficiency (EE)	EE Targets modeled for ECO and WCO; Achievable-Low NM and Low WY allowed for model to select and updated per Mesa Point 2023 DSM Potential Study[5]
Environmental	Emissions and Water Use Rates	Updated generator emission and water use rates per TS Environmental and eGrid 2021 rates, as applicable. Thermal resource rates were provided by B&V, while rates for innovative technologies were sourced from public resources.
	Emissions Reduction Targets	26% in 2025 36% in 2026 46% in 2027 80% in 2030
	APCD Workbook Inputs and Resource, Market & Contract Emissions Rates	*2005 Emissions Baseline:* Updated to reflect Partial Requirements Contracts and Member Exits
		Market & Contract Emissions Rates:[6] Generator Resource emission rates updated per TS Environmental. Basin Eastern Interconnection contract updated to 2021 eGRID MROW rates; Basin Western Interconnection contract proxy emission rate is updated to LRS rate for 2025 and 2021 eGRID rate for 2026 to 2029. Market purchase and

[5] May 2023 "Addendum to 2020 Demand-Side Management and Energy Efficiency Potential Study."
[6] Settlement Agreement section 3.11.3. "…Tri-State will use published system, region or market rates as applicable and consistent with APCD regulations and guidance for unspecified source market and contract purchases…" and section 3.11.4. "…Tri-State will convene a meeting before the next ERP to discuss the emissions rate for unspecified energy purchases…" That meeting was held on August 16, 2022.

		sales updated to 2021 eGRID RMPA and AZNM rates as applicable.
	Social Cost of Carbon	As of February 2021 IWG[7] @ 2.5% discount rate
	Social Cost of Methane	As of February 2021 IWG @ 2.5% discount rate

Financial

Electric and Gas Forward Curves, and Transport Costs

Tri-State has updated the electric and gas forward curves using Horizons Energy's Spring 2023 Advisory Reference Case results. The Advisory Service provides fundamental analysis of electricity markets. Horizons Energy produces the EnCompass National Database for developing fundamental prices of the electricity markets including fuel and energy throughout North America related to integrated resource planning. Horizons Energy used Henry Hub gas forward prices from Natural Gas Intelligence through December 2023 and then trended forward through 2050. Cheyenne Hub forecasted basis is used for CIG and Waha forecasted basis is used for Waha fuel curves. Horizons Energy electric forward curves are provided for the four WECC areas of Eastern and Western Colorado, New Mexico, and Wyoming. Tri-State forward price curve blends all four areas equally for an average hourly market price through 2050. Monthly forward price curves are modeled in real 2023 dollars.

Figure 1 represents the electric forward curve data in real (2023) dollars for the resource planning period (RPP):

Figure 2 represents the gas forward curve in real (2023) dollars.

[7] https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf

[redacted]

Table 1 summarizes the additional transport costs and forward curves associated with each gas generating unit:

Table 1: Transportation Costs & Fuel Forward Curve for Gas Resources

Existing Gas Plant	[redacted]	Forward Curve
Limon	[redacted]	CIG
Knutson	[redacted]	CIG
Pyramid	[redacted]	Waha
JM Shafer	[redacted]	CIG
Generic Gas Resources – CO & WY	[redacted]	CIG
Generic Gas Resources – NM	[redacted]	Waha

Coal Forward Curve

Tri-State's forward coal prices change at least annually. The coal price forecast, including rail delivery fees (or "freight"), are used in EnCompass and in the final PVRR analysis in UIPlanner. Tri-State updated the Craig coal forward curve in March 2023. [redacted]

[redacted]

[redacted]

[redacted]

Capital Expenditures and Fixed O&M

Tri-State forecasts capital expenditures based on actual planned or expected projects. Tri-State updated its capital expenditure forecast for use in the modeling.

[redacted][9]

[redacted]

Tri-State also reviews historical data for O&M costs and incorporates known changes impacting future O&M costs to produce an annual forecast of O&M costs. Tri-State utilized its O&M forecast to derive a new fixed O&M forecast for use in the modeling.

[redacted]

[redacted]

Variable O&M

The variable O&M (VOM) reflects the latest average VOM calculated by Tri-State Generation Engineering for the units. Use of the most recent average VOM results in [redacted]

[9] Axial Basin and Dolores Canyon solar resources are not yet operational; therefore, no capital expenditures have been forecasted. Initial capital construction cost is reflected in the financial analysis.

[redacted] Other units' average VOM costs remained relatively consistent with values used in previous modeling.

[redacted]

Annual Inflation Forecast

Tri-State's financial planning and analysis team applies an assumed rate of inflation to adequately budget fixed costs and modeled capital and O&M expenditures used in ERP modeling throughout the resource planning period. The escalation rate is 2.5% in 2024, 2.2.% in 2025, 2.30% in 2026 and 2027, and 2.15% thereafter.

Depreciation Costs and Schedules

Depreciation costs and schedules for existing resources were modeled based on Tri-State's 2023 Generation Plant Depreciation Study completed in May 2023. Also see Attachment C-3 of the ERP Report (Attachment LKT-1). Generic resource modeling assumptions, including book life and operating life, can be found in Attachment C-2.

Renewable and Storage Generic Resource Prices – PPAs and Build Transfers

Tri-State's consultant, CDG, updated the forward price curves for generic renewable, and hybrid resource Power Purchase Agreements (PPAs) as well as renewable build-transfer and standalone storage build costs reflect updated capital and operating expense forecasts, Inflation Reduction Act (IRA) tax credit additions and extensions (production tax credits (PTC) and investment tax credits (ITC)), 2020 ERP Phase II pricing, and, for generic wind in Wyoming, the Wyoming $1/MWh "Wind Tax" is included.

Gas Generic Resource Build Prices

In 2023, Black & Veatch (B&V) reviewed and refreshed generic gas pricing assumptions for the ERP. The assumptions can be found in Attachment C-2: Generic Resources Summary.

Innovative Technology Pricing

Per the 2020 ERP Phase I Settlement Agreement,[10] Tri-State added new generic resource types (e.g., Small Modular Reactors, Hydrogen, Molten Salt Long-Term Storage, Iron Air Storage, Geothermal, etc.) with associated pricing and technology assumptions, as identified in Attachment C-2: Generic Resources Summary.

Resource Integration Adder (Ancillary Service Costs)

Integration Adders are modeled to reflect the ancillary service cost for generic resources in the Balancing Authority Area (BAA) operating in each Tri-State planning region. The adders were updated to reflect 2023 pricing and were applied in the modeling are as follows:

PNM (NM):

- No extra intermittent resource specific charges

WACM (WCO, WYO-WNYE, and ECO):

- Wind: Schedule 3 Regulation $0.4293/kW month
- Solar: Schedule 3 Regulation $0.8427/kW month

Discount Rate

Tri-State's weighted average cost of capital (WACC), or discount rate, as of February 2023 was 4.12%. For comparison, Tri-State's WACC was 4.18% in 2020 ERP Phase II and 4.15% in 2020 ERP Phase I.

LRS 2 & 3 Retirement Cost Profile

Tri-State's portion of the fixed O&M and capital expenditures for Laramie River Station (LRS) Units 2 and 3 are reflected in the financial analysis for each scenario as a sunk cost, continuing through each unit's useful life. Given that these costs are a contractual obligation, they are not an avoidable cost in the expansion plan modeling.

Springerville Unit 3 Retirement Cost Profile

Springerville Unit 3 (SPV 3) retirement cost profile reflects the latest estimated calculation of the following [redacted]

- [redacted]
- [redacted]
- [redacted]

The SPV 3 retirement cost profile still does not reflect potential penalties or costs associated with early contract termination, or facilities and operational costs for shared facilities under joint ownership, which could occur under an early retirement scenario, but continue to be unknown at this time.

[10] Section 3.11.15 of Attachment A of the Unopposed Comprehensive Settlement Agreement, filed January 18, 2022 in Proceeding No. 20A-0528E.

Craig Station Decommissioning Cost

The cost for decommissioning Craig Station was updated in the financial modeling, replacing the previous internal estimate with an estimate that reflects a third-party quote. The decommissioning cost was also updated to reflect Tri-State's share of the cost.

Book Life for Generic Li-Ion Batteries, Renewables and Gas

Generic resources' book life assumptions are identified in Attachment C-2. Useful life of existing resources is identified in Attachment C-3.

Third Party Transmission

All available third-party transmission between planning regions, whether network or purchased long term firm point to point transmission, is included in the model and associated sunk costs are included in the financial model. Also included in the dispatch model is the option to purchase:

- up to 133 MW of hourly transmission at PSCO's Open Access Transmission Tariff (OATT) rate as needed for additional transfers from ECO to NM;
- up to 76 MW of third-party transmission at CRSP's OATT rate from ECO to WCO at an incremental cost; and
- up to 100 MW of third-party transmission at PNM's OATT rate from NM to ECO at an incremental cost.

Operational

CRSP Hydro Forecast

Energy and capacity profiles for Colorado River Storage Project (CRSP) contracts through the RPP are at normal levels, for the following regions: CRSP ECO, CRSP NM, CRSP WCO. This assumption is in light of the U.S. Bureau of Reclamation's May 2023 projection[11] for the Colorado River system of a 0% probability of minimum power pool through 2027 along with recent improvements in near term hydro allotments.

Load Forecast

The load assumptions used in the modeling are based on Tri-State's latest finalized long-term load forecast produced in June 2022. The methodology used for load forecasting is outlined in Attachment F of the ERP Report (LKT-1). Adjustments were made to the forecast to reflect Member exits,[12] Partial Requirements contract load reductions, Colorado energy efficiency, system-wide beneficial electrification for the Tri-State system, and member distributed generation.

Member exits assumed include the following:

- United Power exiting May 1, 2024;
- Northwest Rural Public Power District (NRPPD) exiting May 1, 2024; and

[11] https://www.usbr.gov/lc/region/g4000/riverops/crss-5year-projections.html

[12] Paragraph 63 of Decision No. C23-0437, issued in Proceeding No. 20A-0528E, directed Tri-State to "…submit a load forecast that is indicative of anticipated member departures at the time of filing…"

- Mountain Parks exiting February 1, 2025.

Tri-State is no longer planning its system or acquiring resources to serve the load and reliability needs of these three Members, therefore they are not included in the resource plan.

Separate from the gross load forecast, an offset for 280 MW of Partial Requirements[13] load reduction is included in the model. The quantity of Partial Requirements Member MAX selections known at the time of the start of modeling is 163 MW beginning in 2026 and the quantity for MARS selections is 117 MW beginning in 2026. Based on this, the 163 MW MAX selections reduce the system capacity that Tri-State is responsible for by 163 MW, but the 117 MW MARS selection is a capacity reduction at a prorated amount equivalent to the type of intermittent resource selected (modeled as utility-scale solar). Partial Requirements elections reflect May 2021 and May 2022 Open Seasons, excluding Mountain Parks' election.

System-wide beneficial electrification, discussed below, is added to the load forecast, and Colorado energy efficiency targets—which were modeled as a base assumption in every scenario rather than as a selection by the dispatch model—are subtracted from the gross load forecast in modeling every scenario. Member-owned renewable or distributed generation projects are a deduction to gross load in the modeling process.

Beneficial Electrification

Beneficial Electrification (BE) is included in ERP modeling as additional load in the load forecast. An Achievable-Moderate level BE is modeled for all planning regions in all 2023 ERP Phase I scenarios in alignment with the 2020 ERP Phase I Settlement Agreement.[14] The Achievable-Moderate level of BE load is determined by the BE Potential Study (Attachment G-3 of the ERP Report (LKT-1). "Achievable" potential takes into account barriers that hinder consumer adoption of measures and the capability to ramp up BE program activity over time. The BE Potential Study incorporated the following BE technologies and program opportunities: electric building heating measures, electric vehicles and non-road electric vehicles, cooking measures, and electric equipment such as lawn and garden equipment.

The Achievable-Moderate level of potential assumes BE measures are incented at 50% of the incremental cost, resulting in ~668 GWh of cumulative growth on the Tri-State system through 2040 (roughly 4.4% addition to 2040 base gross load). In the ERP financial analysis, the cost of attaining an Achievable-Moderate level of BE is reflective of Tri-State BE staff forecasted expenditures for incentives and program delivery.

Distributed Generation Forecast

Distributed generation (DG) forecast consists of energy and demand forecasts on a project level for Member self-supply options, including Board Policy 115 – renewable distributed generation on Member Systems, Board Policy 119- Community Solar, and Partial Requirements MARS options. Projects are forecasted based on technology type and location with the use of historical load shapes where available.

[13] Partial Requirements Members can select MAX (Firm capacity) or MARS (intermittent resource) options.
[14] Section 3.11.11.

Constraints

See Attachments B-1 and B-2 of the ERP Report (LKT-1).

Level I & II Reliability Metrics

All 2023 ERP scenarios were modeled to achieve the minimum Level I and II Reliability Metrics identified in the ERP Report (LKT-1).

Thermal Build Constraint

No new thermal builds allowed until 2028 due to infeasibility of engineering, procurement, construction, and permitting completion prior to 2028.

Gas Retirement Constraint

Gas and oil units, including those with dual-fuel capability available for contingency operations are not allowed to retire in the modeling given that they are necessary for maintaining reliability. These units operate during extreme weather events, support market price arbitrage to reduce costs, support reliability during coal unit outages, and can offer surplus interconnection benefits for co-located renewable resources.

Coal Unit Uptime

Minimum run-time for all coal units was set to 12 hours in the modeling, reflective of a May 2020 report[15] by the Western Electricity Coordinating Council (WECC).

Coal Unit Downtime

Minimum down-time for all coal units was set to 8 hours in the modeling, reflective of a May 2020 report[16] by the WECC.

Craig 3 Modeling

Per the 2020 ERP Phase I Settlement Agreement,[17] Tri-State modeled Craig 3 in the ECON designation, allowing the model to economically commit and dispatch the unit subject to the minimum up and down times.

Craig Unit Retirements

Craig Units 1 and 2 retirements are modeled to occur on the announced dates; and Craig Unit 3 is modeled to allow the unit's retirement between January 1, 2028 and December 31, 2029, except where otherwise modeled per unique scenario assumptions (see Attachment B-3: Unique Scenario Assumptions of the ERP Report (LKT-1)). Craig Unit 3 is not allowed to retire prior to January 1, 2028 in the modeling to ensure sufficient lead-time for the community transition between completion of the 2023 ERP and the earliest potential retirement date and to allow sufficient time for replacement resources to be secured. Craig Unit

[15] *Update of Reliability and Cost Impacts of Flexible Generation on Fossil-fueled Generators for Western Electricity Coordinating Council*, May 12, 2020; Table 2, page 21 (720 minutes Minimum Up Time for coal units). Available: 1r10726 WECC Update of Reliability and Cost Impacts of Flexible Generation on Fossil.pdf.
[16] *Update of Reliability and Cost Impacts of Flexible Generation on Fossil-fueled Generators for Western Electricity Coordinating Council*, May 12, 2020; Table 2, page 21 (480 minutes Minimum Down Time for coal units). Available: 1r10726 WECC Update of Reliability and Cost Impacts of Flexible Generation on Fossil.pdf.
[17] Section 3.6.6.

3 is not allowed to retire later than December 31, 2029 given that date is the publicly announced retirement date for the unit as identified in Colorado Regulation No. 23 Regional Haze Limits.

Tri-State Exit MBPP

Tri-State has no current plans to exit the Missouri Basin Power Project ("MBPP"). Tri-State is an MBPP participant and receives a portion of Laramie River Station (LRS) generation and transmission through its share of the MBPP contract. Tri-State is only a partial owner of LRS, therefore any "LRS early retirement" modeling simulates Tri-State exit of the MBPP Agreement, not retirement of the unit. This assumption is applied to be informative to the resource plan modeling.

SPV 3 Retirement

SPV 3 is allowed to retire beginning January 1, 2037, upon the conclusion of the 100 MW third-party supply contract (Fall 2036), except where otherwise modeled per unique scenario assumptions (see Attachment B-3 of the ERP Report (LKT-1)).

SPV 3 Max Capacity

In July 2022, a capacity test was conducted affirming the previous maximum capacity rating for SPV 3 of 419 MW.

Effective Load Carrying Capability

ELCCs were updated for wind, solar, storage, coal, and gas resources for the 2023 ERP based on the third-party study completed in August 2023. The ELCC methodology and study results are provided in Attachment G-1 of the ERP Report (LKT-1). For capacity expansion modeling, firm capacity of each unit reflects the Equivalent Forced Outage Rate (eFOR) by unit identified in *Table 18. TSGT UCAP Capacity* of Attachment G-1 of the ERP Report (LKT-1).

Scheduled Outages

The following identifies the scheduled outages modeled for coal units during the RAP.

Table 4: Scheduled Coal Unit Outages During the RAP

[redacted]

Forced Outage Factors

Dispatch plan modeling reflects the average FOFs by unit,[18] as shown in Table 5.

Table 5: Thermal Unit Forced Outage Factors (FOFs)

Unit	5-yr Average FOF (%)
Craig 1	4.00
Craig 2	2.05
Craig 3	13.89
LRS 2	6.49
LRS 3	7.18
SPV3	5.78
Burlington 1	0.99
Burlington 2	0.53
Knutson 1	1.98
Knutson 2	0.72
Limon 1	0.67
Limon 2	0.33
Pyramid 1	0.19
Pyramid 2	1.24
Pyramid 3	0.44
Pyramid 4	0.95
JM Shafer	4.71

These FOF factors were developed using five years of historical FOFs data from 2018-2022, shown in Table 6.

Table 6: Historical Thermal Unit FOFs

Unit	2018	2019	2020	2021	2022
Craig 1	5.53	1.21	3.35	8.18	1.75
Craig 2	0.27	2.18	0.99	2.17	4.65
Craig 3	45.24	3.39	3.67	4.36	12.78
LRS 2	6.33	2.20	7.82	12.71	3.39
LRS 3	0.01	0.51	10.34	23.47	1.56
SPV3	7.77	9.09	1.41	7.8	2.82
Burlington 1	2.46	0.70	0.43	1.34	0
Burlington 2	0.67	0.32	0.35	0.87	0.45
Knutson 1	0.33	0.89	0.22	0.03	8.45
Knutson 2	0.21	0.66	1.55	0.4	0.77
Limon 1	1.71	0.29	0.06	0.01	1.29

[18] The input field in EnCompass is FOR.

Unit	2018	2019	2020	2021	2022
Limon 2	0.45	0.57	0.12	0.45	0.07
Pyramid 1	0.27	0.35	0.02	0.02	0.31
Pyramid 2	2.76	0.07	0.39	0	2.97
Pyramid 3	0.26	0.97	0.91	0.08	0
Pyramid 4	0.26	2.41	0.18	1.88	0
JM Shafer	5.04	13.13	1.46	2.12	1.8

EnCompass randomly selects for each day how many individual units will be forced out due to operational failure. This random selection is based on the FOR and Random Outage Seed inputs. The model uses the FOR to determine the number of full forced outage days per year and will randomly select the dates in each year.

Modeling of Market Sales and Purchase Depths

All market purchases and sales are transacted at a regional level trading hub within the model. Market depths in 2024 are reflective of Member exits, and access to existing Western Energy Imbalance Market (WEIM) and Western Energy Imbalance Service (WEIS) markets. Market depths beginning in 2026 are reflective of the WACM BA moving to SPP RTO. Additional market depth in ECO is added in 2030 reflective of an assumption that PSCo will be in an RTO by 2030. Market depths in New Mexico are reflective of assumptions that PNM joins an RTO by 2030. The tables below show the market depths as modeled.[19]

Table 7: Market Sales Characteristics

Market	2024-March 2026	April 2026-2029	2030-
	ATC (MW)	ATC (MW)	ATC(MW)
ECO	200	250	300
WCO	100	200	200
NM	75	75	150
WYO-WNE	100	200	200

Table 8: Market Purchase Characteristics

Market	2024-March 2026	April 2026-2029	2030-
	ATC (MW)	ATC (MW)	ATC (MW)
ECO	150	200	200
WCO	100	200	200
NM	100	100	200
WYO-WNE	75	200	200

Tri-State currently meets its contingency reserve requirements through its membership in the Southwest Reserve Sharing and two sub-entity Reserve Sharing Group agreements. Modeling includes contingency

[19] Market sales were reviewed by a third-party consultant in May 2023.

reserve requirements for these existing reserve sharing groups. Potential regulation and contingency reserve sales opportunities within the SPP RTO are not reflected in the Phase I modeling.[20]

Modeling of Short & Long-Term Sales

Modeling reflects existing term sales as follows:

- **City of Farmington Sale** (Modeled as a Term Sale)**:** 25 MW per hour maximum on-peak capacity; 15 MW per hour maximum off-peak capacity ~181 GWh/year in energy sales. Effective date 7/1/23; contract expires 12/31/25.
- **DOE National Nuclear Security Administration Sale** (Modeled as a Term Sale)**:** Up to 40 MW capacity, ~351 GWh/year in energy sales. Contract is effective from 1/1/24-12/31/25.
- **SRP Sale:** SPV 3 located in Arizona, 100 MW (Maximum Capacity) ~375 GWh/year. Effective Date 10/20/2003; Contract Expires 8/31/2036. In some of the modeled scenarios, Springerville 3 is retired before the end of the contract date. Tri-State cannot terminate operations of Springerville 3 and the related third-party contract without reaching agreement with impacted parties.

Modeling of Proxy Sales

Tri-State modeled proxy sales for near-term years in anticipation of the ability to sell excess power upon Member exits. Proxy sales include:

- [redacted]
- [redacted]

In September 2023, Tri-State issued a reverse RFP and resulting potential sales are still under evaluation with some negotiations in progress.

Generic Resource Availability

The model is able to select generic resources to be added in the expansion plan starting as soon as 2026, depending on lead time of each technology as identified in Attachment C-2 of the ERP Report (LKT-1).

PPA and Contract Information

Modeling reflects PPA capacity, energy, and CoDs shown in Attachment C-1 of the ERP Report (LKT-1). Tri-State's modeling reflected known PPA updates, including:

- Escalante Solar commercial operation date (COD) was advanced from December 2024 to June 2024 based on updated project schedule. Escalante Solar was modeled through December 2043, the end of the Resource Acquisition Period.
- Axial Basin and Dolores Canyon are no longer PPAs and were modeled as Tri-State owned resources.[21]

[20] Tri-State is evaluating the potential to model these opportunities in Phase II of the 2023 ERP.
[21] See Attachment C-3 of the ERP Report (LKT-1). Also see Proceeding No. 23A-0548E.

After scenario modeling began, additional PPA changes occurred:

- Due to global supply chain and tariff uncertainties impacting construction schedules, the Coyote Gulch Solar PPA was terminated, effective October 1, 2023.[22]
- Additionally, due to similar reasons noted above, the price increased from [redacted] for the Spanish Peaks and Spanish Peaks II PPAs. Simultaneous to the price modification, the Spanish Peaks and Spanish Peaks II PPAs were also extended for four additional years, from a 2039 contract end date to 2043 (making them 19-year PPA terms).[23]

SRP Contract

Salt River Project (SRP) is assumed to take at least the contract minimum capacity amount from SPV 3, but if the cost of SPV 3 energy is lower than forecasted market prices, the SRP take can be modeled above the contract minimum, up to the max contract capacity (100 MW).

System Loss Factor

The transmission system loss factor is meant to represent an average of expected transmission losses as Tri-State load in the Western Interconnection is located across multiple BAs and Transmission Provider systems. The transmission loss factor used in the planning and dispatch models was 3.5% in the Wyoming, Western Colorado, and Eastern Colorado planning regions. A portion of transmission system losses are financial, and are recorded in the financial models as a purchase power expense.

Demand-Side Management

Demand Response

For the ECO and WCO planning regions, Tri-State models achievement of the "DR Target." The DR Target[24] requires Tri-State to "…develop in-house demand response offerings in Colorado by 2025 that are designed to control at least 4% of Tri-State's Colorado peak load." Tri-State bases its DR modeling on the programs it anticipates launching, which include controls for: water heaters and air conditioners for residential and small commercial settings, irrigation load, and commercial and industrial (C&I) applications. Tri-State also models Low DR for WYO-WNE and NM planning regions,[25] which is generally consistent with internally-forecasted levels of uptake of DR programs.

Modeling the DR Target for ECO and WCO involves the following input assumptions and parameters:

- DR Target of at least 4% MW is a must-take, not a selection in the model.
- There are five different "DR resource" types: (1) Commercial & Industrial (C&I), (2) Irrigation, (3) Residential Battery Energy Storage Systems (BESS), (4) Residential Air Conditioning (A/C), and

[22] The Coyote Gulch Solar PPA was cancelled subsequent to initiation of Phase I scenario modeling, and therefore was included in the modeling, with a July 2026 COD. Replacement capacity will be procured through 2023 ERP Phase II.
[23] These contract modifications occurred subsequent to initiation of Phase I scenario modeling.
[24] See 2020 ERP Phase I Settlement Agreement, section 3.11.8.
[25] "Low DR" is based on the DSM and EE Potential Study completed by MesaPoint Energy for the 2020 ERP, May 8, 2020.

18(5) Residential Water Heaters (WH). Each has different values for Max Capacity, Maximum Daily Energy, Maximum Annual Energy, and Payback Required.

- **Max Capacity** sets the daily maximum output for each DR resource;
- **Maximum Daily Energy (%)** sets the maximum capacity factor for each day, limiting daily output to this input capacity factor;
- **Maximum Storage (MWh)** sets the maximum amount of energy that can be stored at any given time; and
- **Maximum Annual Energy (%)** sets the maximum capacity factor for the year.
- **Payback Required (%)** sets the percentage rate at which the interrupted load requirements need to be replaced.

- DR resource costs assumed for meeting the DR Target for ECO and WCO, both programmatic and incentive costs, are included in each scenario's financial analysis (i.e., revenue requirements), applied across the "lifetime" of the DR resources. The costs were provided by Tri-State's DSM department.

DR is dispatched by the model by determining the most economical way to dispatch DR thus shifting load while adhering to the hourly constraints and payback requirements in a given hour, day, and season. For example, the C&I DR resource is able to be called on year-round, but only during hours 8-16 (nine hrs/day) up to 14.5 MW in 2030, but only up to 8.6 GWh/yr (6.8% of annual capacity), and only can dispatch six of the nine hours in a given day (6/24 = 25% of Maximum Daily Energy). Also, DR resources are modeled like a battery in that whatever demand energy is curtailed, some amount of payback is required. In the case of the C&I DR resource, a 50% payback is required, so, for example, in year 2030 if it curtails 8.6 GWh/yr, 4.3 GWh/yr is paid back.

Modeling DR resources for WYO-WNE and NM involves the following input assumptions and parameters:

- DR resources can be selected by the model for WYO-WNE and NM.
- All of the five DR resources together are one Project in Encompass with an associated capital cost (CapEx) based on the present value of the lifetime expenditures for that project. If the Project is the most economic choice for meeting system load needs then the Project is selected and the associated Capex is modeled as an expenditure and the DR resource parameters (Max Capacity, etc. noted above) are applied in the modeling.
- The costs associated with the selected DR resources for WYO-WNE and NM, both the programmatic and incentive costs, are included in each scenario's financial analysis (i.e., revenue requirements) applied across the "lifetime" of the DR resources. The costs were provided by Tri-State's DSM department.

Because much of DR reflects shifts in the time periods when energy is used, financial models – which focus on energy billed to members within a month – show DR energy impacts net of timing shifts.

Energy Efficiency

ECO and WCO regions were modeled to achieve the EE Targets[26] of 0.35% in 2023, 0.5% by 2024, 0.75% by 2025, and 1% by 2030 in incremental annual energy efficiency savings for Colorado Utility Member

[26] *See* 2020 ERP Phase I Settlement Agreement, Section 3.11.9.

system load.[27] See table below for estimated energy equivalents for EE Targets based on the latest load forecast.[28] WYO and NM regions were allowed to select Achievable-Low EE[29] starting in 2025.

Table 9: Colorado Energy Efficiency Targets and GWh Equivalent

Target Year	EE Target (%)	Est. GWh Equivalent
2023	0.35%	39.0
2024	0.50%	145.6
2025	0.75%	59.0
2030	1.00%	73.4

Environmental

Emission and Water Use Rates

Emission rates (lbs/MWh) and water use (gal/MWh)[30] for existing units were updated based on 2022 actual emissions, water use, and net generated MWh for each generator. Emissions rates and water use for generic thermal resources were reviewed and updated by B&V in Spring 2023. Emission rates and water use for innovative technologies were based on industry research and developer specs, where available. Emission and water use rates used for 2023 ERP Phase I modeling are shown in the table below. Also see Attachment C-2 of the ERP Report (LKT-1).

Table 10: Emission and Water Use Rates

	CO_2	SO_2	NOx	Hg	PM	VOC	Water Usage
UNIT	lbs per Net MWh	lbs per Net MWh	lbs per Net MWh	lbs per Gross MWh	lbs per Gross MWh	lbs per Gross MWh	(gal/MWh)
LRS 2	2489	1.414	1.693	0.00001	0.126	0.0325	685
LRS 3	2489	1.414	1.693	0.000	0.126	0.0325	685
Craig 1[31]	2388	0.604	2.790	0.0000040	0.104	0.0021	573
Craig 2	2388	0.526	0.801	0.0000038	0.117	0.0019	573
Craig 3	2204	1.332	2.240	0.0000065	0.040	0.0299	573
Springerville 3	2372	0.990	0.857	0.0000043	0.196	0.0325	548

[27] There were two minor inputs to energy efficiency that were incorrectly reflected in calculation of Colorado load for purposes of determining EE Targets in the modeling: 1) Partial Requirements deductions from total load started in 2025 instead of 2026; and 2) deductions for *all* Partial Requirements member elections were deducted from Colorado load requirements for purposes of calculating energy efficiency in the modeling, but should not have included non-Colorado partial requirements. The magnitude of this impact is immaterial, at less than a tenth of a percent.

[28] Page 27 of Tri-State's informational DSM plan filed in Proceeding No. 20A-0528E on September 1, 2022 contained EE Targets forecasted based on Tri-State Colorado system load at that time.

[29] Attachment G-3 of the ERP Report (LKT-1).

[30] Pursuant to Rule 3605(a)(IV)(I).

[31] NOx limits for Craig 1 are in place to comply with the Colorado State Implementation Plan related to the Regional Haze rule.

	CO_2	SO_2	NOx	Hg	PM	VOC	Water Usage
UNIT	**lbs per Net MWh**	**lbs per Net MWh**	**lbs per Net MWh**	**lbs per Gross MWh**	**lbs per Gross MWh**	**lbs per Gross MWh**	**(gal/MWh)**
Burlington 1	2121	0.063	10.633	*N/A*	0.145	0.0050	10
Burlington 2	2121	0.063	10.895	*N/A*	0.149	0.0051	10
Pyramid 1	1232	0.010	1.394	*N/A*	0.074	0.0213	40
Pyramid 2	1232	0.008	1.127	*N/A*	0.068	0.0205	40
Pyramid 3	1232	0.017	1.285	*N/A*	0.079	0.0184	40
Pyramid 4	1232	0.009	1.147	*N/A*	0.070	0.0207	40
Limon 1	1594	0.009	0.294	*N/A*	0.067	0.0026	32
Limon 2	1594	0.011	0.387	*N/A*	0.079	0.0028	32
Knutson 1	1515	0.011	0.387	*N/A*	0.118	0.0008	17
Knutson 2	1515	0.010	0.329	*N/A*	0.118	0.0008	17
J. M. Shafer	985	0.005	0.725	*N/A*	0.053	0.0465	343
Unspecified Energy Purchases	**Years 2023 - 2029**						
Basin Nebraska	996	0.981	0.822	*N/A*	*N/A*	*N/A*	*N/A*
Basin Electric- CO/WY thru 2025	2596	1.299	1.443	*N/A*	*N/A*	*N/A*	*N/A*
Basin Electric- CO/WY 2026-2029	1159	1.299	1.443	*N/A*	*N/A*	*N/A*	*N/A*
Market Purchases	1159	0.344	0.591	*N/A*	*N/A*	*N/A*	*N/A*
Energy Imbalance	1159	0.344	0.591	*N/A*	*N/A*	*N/A*	*N/A*
Gas Expansion Plan Units							
46_5x9RICE	981	0.010	0.180	*N/A*	0.042	0.089	0
40_1x40LM6000	1089	0.011	0.084	*N/A*	0.069	0.027	40
200_1x235_7FA05	1165	0.012	0.090	*N/A*	0.073	0.029	57
Natural Gas CCS	765	0.008	0.046	N/A	0.048	0.019	348
Innovative Tech - Expansion							
Blue Hydrogen w/CCS	59		0.19				570
Green Hydrogen	0		1.06				357
Nuclear SMR	N/A						672
Geothermal EGS/Adv	N/A						100
Non-Emitting Technology with Water Usage	*Note:* Net battery generation is negative; the negative water usage, when applied to negative generation, results in positive overall water usage for non-emitting technology with water usage.						
10 Hour Battery	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	0
Battery - Iron Air	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	-24.7
Molten Salt Storage	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	-51
Pumped Hydro	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	-412

Emissions Reduction Targets

All portfolios are modeled to achieve at least the Interim-Year Emissions Reductions and 2030 Emissions Reduction Targets.[32] Also see Attachment B-3 of the ERP Report (LKT-1).

APCD Workbook Inputs and Resource, Market & Contract Emissions Rates

As shown in Attachments D1-D5 to the ERP Report (LKT-1), the APCD Workbooks for each scenario, Tri-State's 2005 carbon emissions baseline reflects adjustments necessary to exclude Member Exits and Partial Requirements contracts from the baseline in relevant years. Details regarding Member Exits and Partial Requirements are described above, see *Load Forecast*.

Additionally, market and contract emissions rates were updated as follows:

- Basin Eastern Interconnection contract updated to 2021 eGRID MROW rates;
- Basin Western Interconnection contract updated to LRS emission rates for 2025, and 2021 eGRID RMPA rate for 2026 to 2029; and
- Market purchase and sales updated to 2021 eGRID RMPA and AZNM rates as applicable.

Social Cost of Carbon

Social Cost of Carbon ("SCoC") is based on the latest values published by the Interagency Working Group (IWG) on the Social Cost of Greenhouse Gases, for calculating the net present value of carbon dioxide emissions, brought back to present value with a 2.5% discount rate.[33] The values, which are in 2020 real dollars, are inflated using the inflation rate assumptions used throughout the ERP.

Social Cost of Methane

Social Cost of Methane ("SCoM") is based on the latest values published by the IWG on the Social Cost of Greenhouse Gases, for calculating the net present value of methane emissions, brought back to present value with a 2.5% discount rate.[34] The values, which are in 2020 real dollars, are inflated using the inflation rate assumptions used throughout the ERP.

[32] See 2020 ERP Phase I Settlement Agreement, Sections 3.3.4 and 3.3.5.
[33] The IWG has not published an update to SCoC values or the discount rate since February 2021.
[34] The IWG has not published an update to SCoM values or the discount rate since February 2021.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-89:
Tri-State 2025 ERP Annual Progress Report

Colorado PUC E-Filings System

Tri-State Generation and Transmission Association, Inc.

2025 Annual Progress Report

2023 Electric Resource Plan

Colorado Public Utilities Commission
Proceeding No. 23A-0585E

December 1, 2025

Forward-Looking Statement

Forward-looking statements include statements concerning our plans, objectives, goals, strategies, future events, future revenue or performance, forecasts, including load, energy, resources, and commodities, future capital expenditures, capacity needs, plans or intentions relating to development, acquisition, operation, or closure of facilities, in-service dates of facilities, emission reductions, demand response targets, energy efficiency targets, Member withdrawals, business trends or business strategy and other information that is not historical information. When used in this Annual Progress Report, the terms "estimates," "expects," "anticipates," "projects," "plans," "intends," "believes" and "forecasts" or future or conditional verbs, such as "will," "should," "could" or "may," and variations of such words or similar expressions, are intended to identify forward-looking statements. These forward-looking statements are subject to a number of risks, uncertainties, and assumptions, including those described in our filings with the Securities and Exchange Commission. All forward-looking statements, including, without limitation, management's examination of historical operating trends and data, are based upon our current expectations and various assumptions. These expectations and beliefs are expressed in good faith grounded in a reasonable basis. However, we cannot guarantee that management's expectations and beliefs will be achieved. There are a number of risks, uncertainties, and other important factors that could cause actual results to differ materially from the forward-looking statements contained in this Annual Progress Report.

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3. Updated Evaluation of Planning Reserve Margins and Contingency Plans 8
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Introduction

Tri-State Generation and Transmission Association, Inc. ("Tri-State") filed Phase I of its 2023 Electric Resource Plan ("ERP" or "Resource Plan") with the Colorado Public Utilities Commission ("Commission") on December 1, 2023 in Proceeding No. 23A-0585E. At the time of this report, Phase II resource acquisitions remain ongoing, pursuant to Decision No. C25-0612. In compliance with Commission Rule 3618(a), Tri-State submits the following Annual Progress Report ("APR") on its efforts under its electric resource plan.

As discussed below, Tri-State is forecasting a need for 19 MW of additional generation capacity by summer 2035.[1] This forecast incorporates existing resources, 2023 ERP Phase II preferred portfolio resources, and planned unit retirements.

This 2025 APR contains the following sections, in compliance with Commission Rule 3618(a):

A. An updated annual electric demand and energy forecast;
B. An updated evaluation of existing resources;
C. An updated evaluation of planning reserve margins and contingency plans;
D. An updated assessment of need for additional resources;
E. An updated report of the utility's action plan and resource acquisitions; and
F. An explanation of Tri-State's efforts to give the fullest possible consideration to the cost-effective implementation of new clean energy and energy-efficient technologies in its consideration of generation acquisitions.
G. An update on Tri-State's progress toward its GHG emissions reduction targets.

The intent of the APR is to discuss material changes in assumptions, fleet characteristics, load forecasts and other factors that have occurred since the 2024 APR and 2023 ERP Phase II were filed. To the extent issues addressed in Tri-State's 2024 APR or 2023 ERP Phase I and Phase II filing have not materially changed, they are not addressed herein.

[1] 2024 APR: 11 MW need projected stating in 2030
2023 ERP: 68 MW need projected starting in 2029
2022 APR: 126 MW need projected starting in 2030
2021 APR: 248 MW need projected starting in 2030
2020 ERP: 95 MW need projected starting in 2029
2019 APR: 70 MW need projected starting in 2027
2018 APR: 115 MW need projected starting in 2026
2017 APR: 148 MW need projected starting in 2026
2015 ERP: 9 MW need projected starting in 2023

Tri-State has made several changes to its resource portfolio in recent years reflecting increasing amounts of renewable resources and lower emissions trajectory, notably:

- Craig Unit 1[2] is planned to cease operations by December 31, 2025, Craig Unit 3 will retire January 1, 2028, and Craig Unit 2[3] will retire by September 30, 2028.
- Springerville Unit 3 ("SPV 3") is planned to cease operations by March 1, 2031.[4]
- Two solar projects came online in 2024 in Colorado, Spanish Peaks Solar (100 MW) and Spanish Peaks II Solar (40 MW) in Las Animas County.
- Two solar projects came online at the end of October 2025 in Colorado, Axial Basin Solar (145 MW) in Moffat County and Dolores Canyon Solar (110 MW) in Dolores County.

1. Updated Annual Electric Demand and Energy Forecast

Commission Rule 3618(a)(I)

Tri-State's most current demand and energy forecast was modeled in 2023 ERP Phase II and no subsequent revisions have been made. The forecast reflected in Table 1 represents Tri-State's System Wide annual energy and seasonal peaks as modeled in 2023 ERP Phase II. Subsequent to the commencement of modeling in Phase II, Tri-State received notice from the Northwest Rural Public Power District in Nebraska ("NRPPD") that it intends to depart Tri-State Utility Membership on January 1, 2027. NRPPD is served solely in the Eastern Interconnection through an all requirements contract, and NRPPD's departure does not impact Tri-State's electric demand and energy forecast for purposes of Tri-State's Colorado ERP. [5]

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[2] Tri-State's ownership share is 102 MW (24%) of this unit, which has a total nameplate capacity of 427 MW.
[3] Tri-State's ownership share is 98 MW (24%) of this unit, which has a total nameplate capacity of 410 MW.
[4] Decision No. R24-0602 found that a retirement date of September 15, 2031 for SPV 3 was reasonable contingent upon Tri-State receiving a New ERA funding award and successful negotiation of contractual agreements impacted by the unit's retirement. The New ERA award is contingent upon a March 1, 2031 retirement date for SPV 3, consistent with the requirement for USDA to disperse all New ERA funds by September 30, 2031.
[5] *See* Attachment B to Tri-State's Phase II Implementation Report, filed April 11, 2025 in Proceeding No. 23A-0585E.

TABLE 1 – 10-YEAR DEMAND AND ENERGY FORECAST

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Annual Energy Sales (GWh)	13,051	13,110	13,455	13,642	13,830	14,049	14,289	14,521	14,773	15,036
Winter Peak Demand (MW)	1,865	1,739	1,778	1,825	1,847	1,888	1,886	1,955	1,998	2,038
Summer Peak Demand (MW)	2,344	2,423	2,454	2,431	2,472	2,535	2,583	2,635	2,646	2,629

2. Updated Evaluation of Existing Resources

Commission Rule 3618(a)(II)

Figure 1 below depicts the sources of generation serving Tri-State's 2024 total energy sales. Figure 2 below depicts Tri-State's 2024 capacity by generation source. Tri-State's assessment of its existing resources remains the same as what was presented in Tri-State's 2023 ERP Phase I.

FIGURE 1 – 2024 ENERGY MIX, GROSS SALES

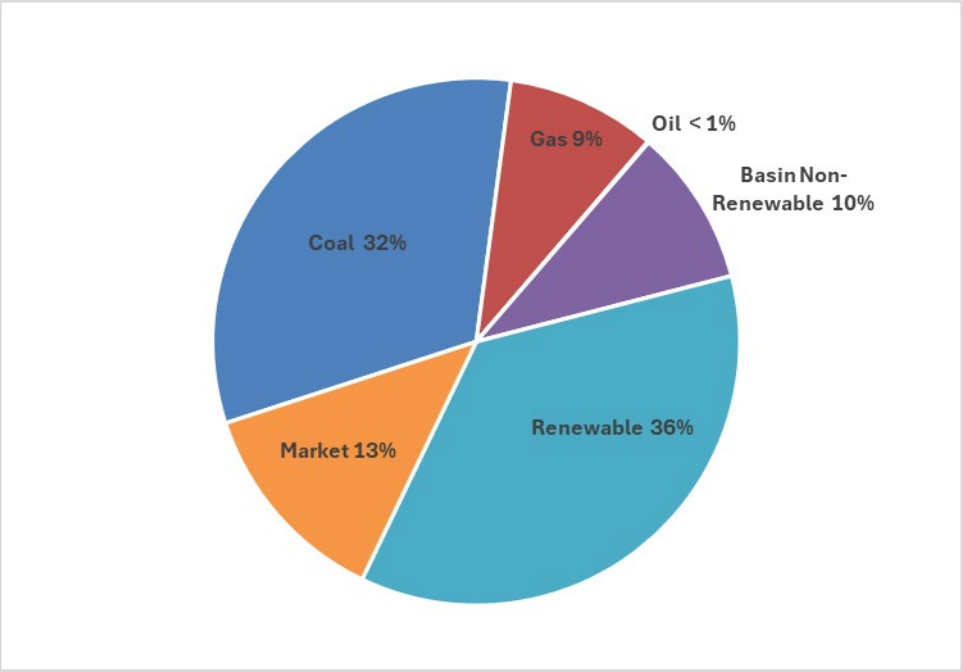
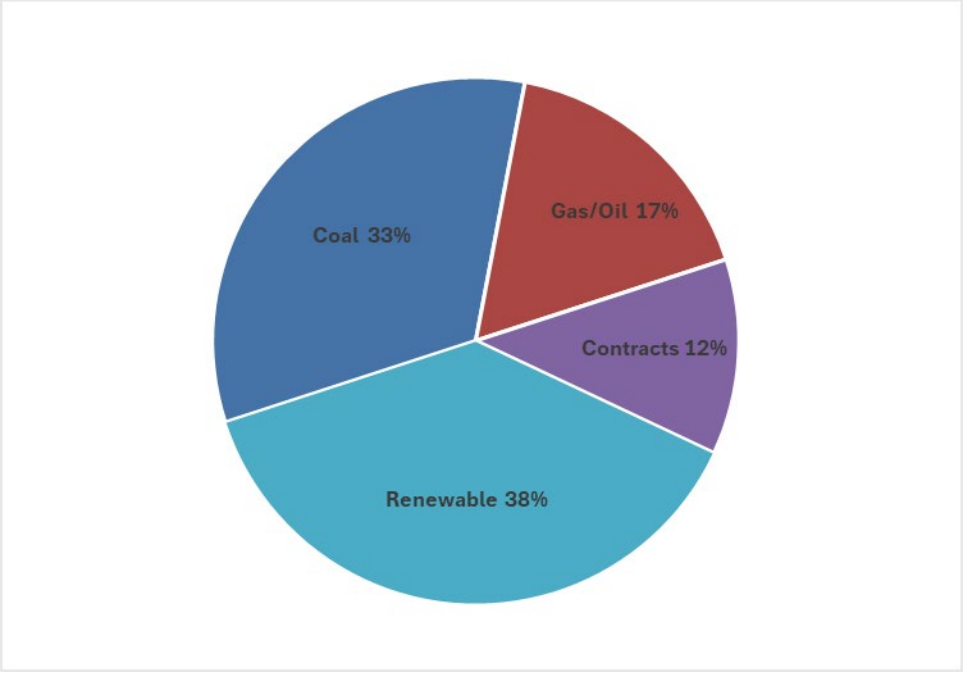


FIGURE 2 – 2024 CAPACITY PORTFOLIO



3. Updated Evaluation of Planning Reserve Margins and Contingency Plans

Commission Rule 3618(a)(III)

There are no updates or changes to the planning reserve margin ("PRM") or contingency plans from those contained in Tri-State's 2023 ERP Phase I or Phase II filing.[6] Tri-State continues to base its resource plans on a 22% PRM until the retirement of Craig Unit 3, after which the PRM increases to 30.5% beginning in 2028. Tri-State's participation in reserve sharing agreements and bilateral hazard-sharing arrangements provide additional support for reliable operations.

Tri-State continues to plan for its WACM load and resources to enter the Southwest Power Pool ("SPP") RTO in April 2026. Once in the RTO, Tri-State's assets in the WACM BA authority will be subject to SPP's PRM requirements. Tri-State is evaluating the SPP PRM requirements and will compare them to Tri-State's most recent PRM requirement. Tri-State intends to follow the more stringent of the two PRM requirements for its system planning.[7]

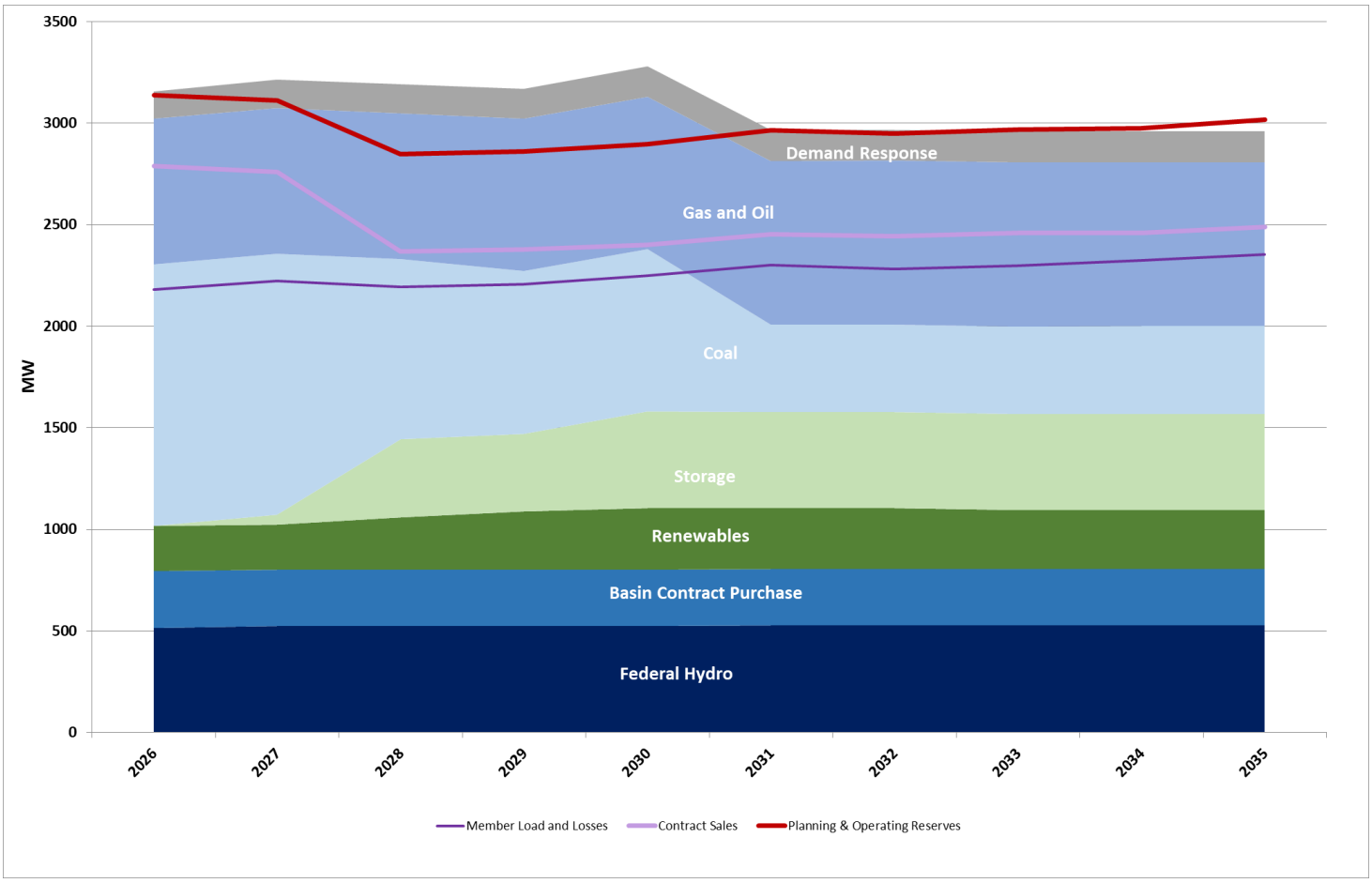
4. Updated Assessment of Need for Additional Resources

Commission Rule 3618(a)(IV)

Tri-State stated within Phase I of the 2023 ERP that it did not forecast a capacity shortfall until 2029. With the updated load forecast, shown above, utilized in Phase II and Phase II preferred portfolio resources, a capacity shortfall is not forecasted to occur until 2035, as shown in Figure 3 and Table 2 below. Tri-State's electrically east load is supplied by a full requirements contract with Basin Electric Power Cooperative and is not included in the load or resource portion of Figure 3 and Table 2.

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

FIGURE 3 –LOAD AND RESOURCES



The data for Figure 3 is shown in Table 2.

TABLE 2 – LOAD AND RESOURCES

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Federal Hydro	516	524	523	524	525	527	527	527	527	527
Contract Purchases	278	278	278	278	278	278	278	278	278	278
Renewables[8]	224	221	259	285	303	299	299	290	291	291
Demand Response	134	141	144	147	149	151	152	153	154	155
Coal Generation[9]	1287	1286	888	800	431	431	432	431	432	431
Gas & Oil Generation[10]	717	717	717	751	751	806	806	806	806	806
Storage[11]	0	49	383	383	474	474	474	474	474	474
Total Resources	3155	3215	3193	3169	3280	2965	2967	2959	2961	2961
Member Load and Losses[12]	2180	2223	2195	2206	2249	2302	2282	2297	2323	2355
Planning & Operating Reserves	350	351	478	482	495	511	505	509	517	527
Contract Sales	608	536	173	173	151	151	162	162	135	135
Total Obligations	3138	3110	2846	2861	2895	2964	2949	2968	2976	3017
Excess Resources	8	89	372	335	412	30	46	19	22	-19

5. Updated Report of the Utility's Action Plan and Resource Acquisitions

Commission Rule 3618(a)(V)

Tri-State's 2023 ERP Phase II procurement process is underway. Bids were received on October 28, 2024, in response to three Phase II requests for proposals.[13] A summary of bids was filed in Proceeding No. 23A-0585E on December 12, 2024;[14] and bids selected in the Phase II preferred portfolio were identified in Tri-State's ERP Implementation Report filed April 11, 2025. Tri-State has 500 MW of preferred portfolio storage resources under contract, 200 MW of preferred portfolio wind resources under contract, and is continuing contracting efforts for other preferred

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

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

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

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

12 Western Interconnection Load.

13 Bids for the Dispatchable RFP were received November 27, 2024.

14 *See* Tri-State's 45-Day Report filed in Proceeding No. 23A-0585E.

portfolio resources, including evaluation of back-up bids as needed. The preferred portfolio bids under contract include:

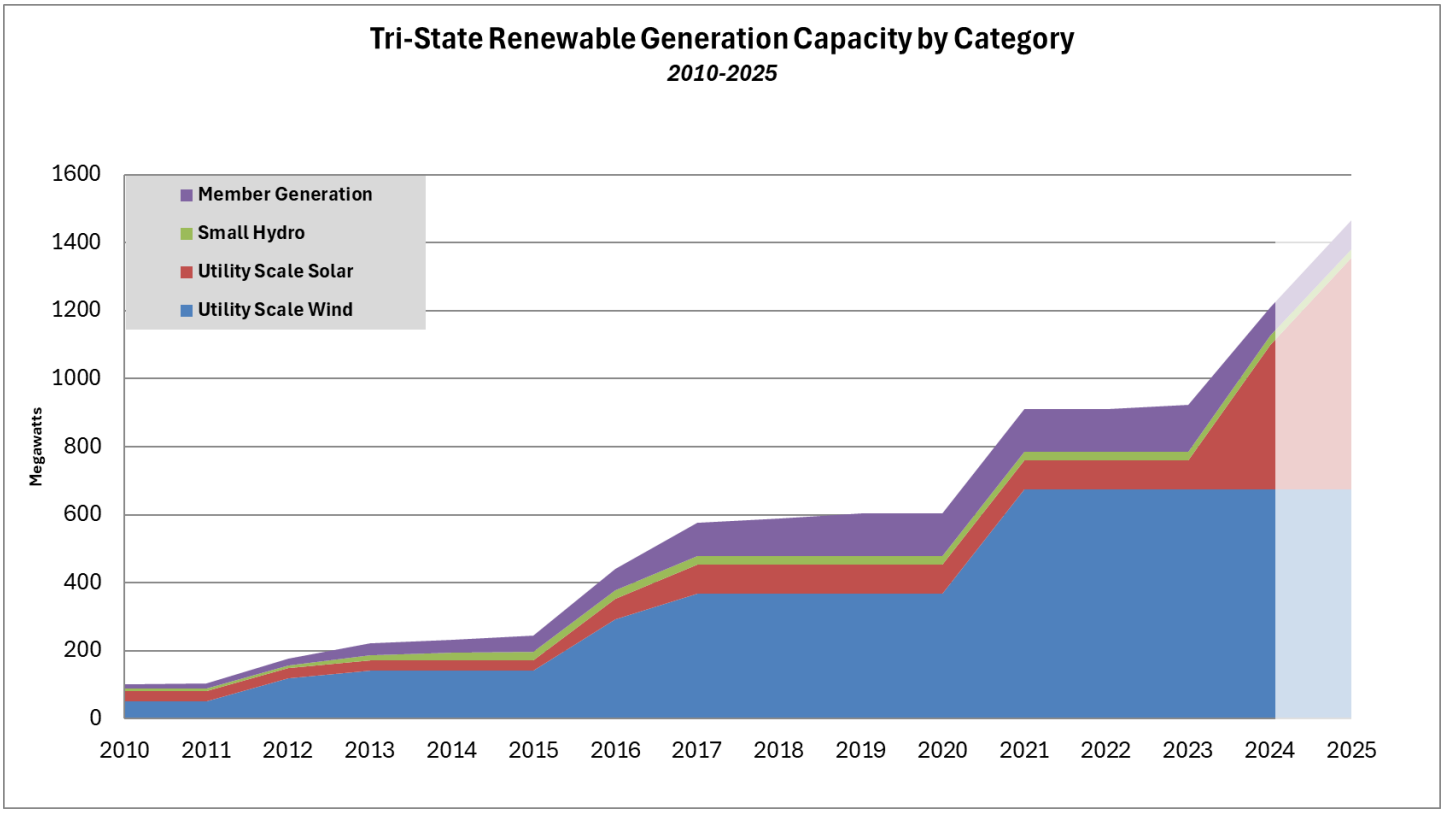
- High Country Energy Station 2 (Montrose County, CO), 50 MW, Q2-2027 COD;
- Oso Negro Energy Storage (Bernalillo County, NM), 100 MW, Q2-2028 COD;
- Morel Energy Storage (Moffat County, CO), 200 MW, Q1-2030 COD;
- Carousel Energy Storage (Kit Carson County, CO), 150 MW, Q4 2027 COD; and
- Arriba Wind (Lincoln County, CO), 200 MW, Q1 2029 COD.

Expansion of Renewable Energy Portfolio

Tri-State's first owned renewable energy resources, Axial Basin Solar (145 MW) and Dolores Canyon Solar (110 MW) came online in October 2025. With those additions, along with existing renewable PPA resources, the renewable resources on Tri-State's system total approximately 2 GW.[15] Tri-State's renewable generation capacity, actuals through 2024 and forecasted for 2025, is shown in Figure 4 below.

[15] 1,466 MW wind, solar, small hydro, and renewable Member generation; and 580 MW large hydro.

FIGURE 4 – TRI-STATE RENEWABLE GENERATION CAPACITY[16]



6. Update on Consideration of Acquisition of Cost-Effective New Clean Energy and Energy-Efficient Technologies

Commission Rule 3618(a)(VI)

Emerging Technologies

Tri-State expanded its generic resource data set for Phase I of the 2023 ERP to include additional clean energy and energy efficient technologies, as technologies continue to evolve and become more competitive.[17] Tri-State utilizes the Electric Power Research Institute ("EPRI") for advanced generation and storage research, input from internal Tri-State Generation Engineering staff, industry benchmarking, and relationships with vendors, stakeholders, and consultants to stay aware of the progress of emerging technologies at a utility scale that can assist in a clean

[16] Figure 4 does not include Western Area Power Administration Colorado River Storage Project or Loveland Area Projects hydro allocations.

[17] *See* Hearing Exhibit 101, Attachment LKT-16, Rev. 2, filed on May 15, 2024, in Proceeding No. 23A-0585E.

energy transition to maintain affordability and reliability for Tri-State's Utility Member Systems. Tri-State will continue to evaluate emerging technologies to consider for its 2027 ERP generic resource data set, to the extent the resources are utility-scale proven and cost-competitive.

Tri-State's entry of its resources into the SPP RTO in April 2026 is key for integrating intermittent resources on a large scale and further supporting affordable and reliable operations, while meeting carbon reduction targets.

Renewables

Tri-State's renewable resource portfolio includes utility scale projects and distribution level projects. Tri-State's wholesale power contract with each of its Utility Members and Board policies allow for, and facilitate, the development of local distributed resources in its Utility Members' service territories. The Federal Energy Regulatory Commission ("FERC") accepted, subject to refund and settlement procedures, Tri-State's amended Board Policy 115 effective August 6, 2025, enabling Utility Members to now self-supply up to 20% of their energy needs through distributed or renewable generation, a substantial increase from the previous 5% allocation. These renewable and distributed projects are helping to fulfill both Colorado and New Mexico Renewable Energy Standards ("RES")/Renewable Portfolio Standards ("RPS") requirements, as well as satisfy Utility Members'/consumers' interests in purchasing renewable power from locally-sited projects.

Figure 5 below shows the decline in capacity of these distributed projects through the end of 2024, reflecting the departures of United Power and Mountain Parks Electric, accounting for a decrease in distributed generation capacity of 49.6 MW. The number and capacity of these projects is expected to continue to grow, with a small net increase in 2025, as many of Tri-State's Utility Members remain interested in supporting local renewable projects.

FIGURE 5 – MEMBER RENEWABLE AND DISTRIBUTED GENERATION PROJECTS, NAMEPLATE CAPACITY UNDER CONTRACT, 2007-2024 AND FORECASTED for 2025

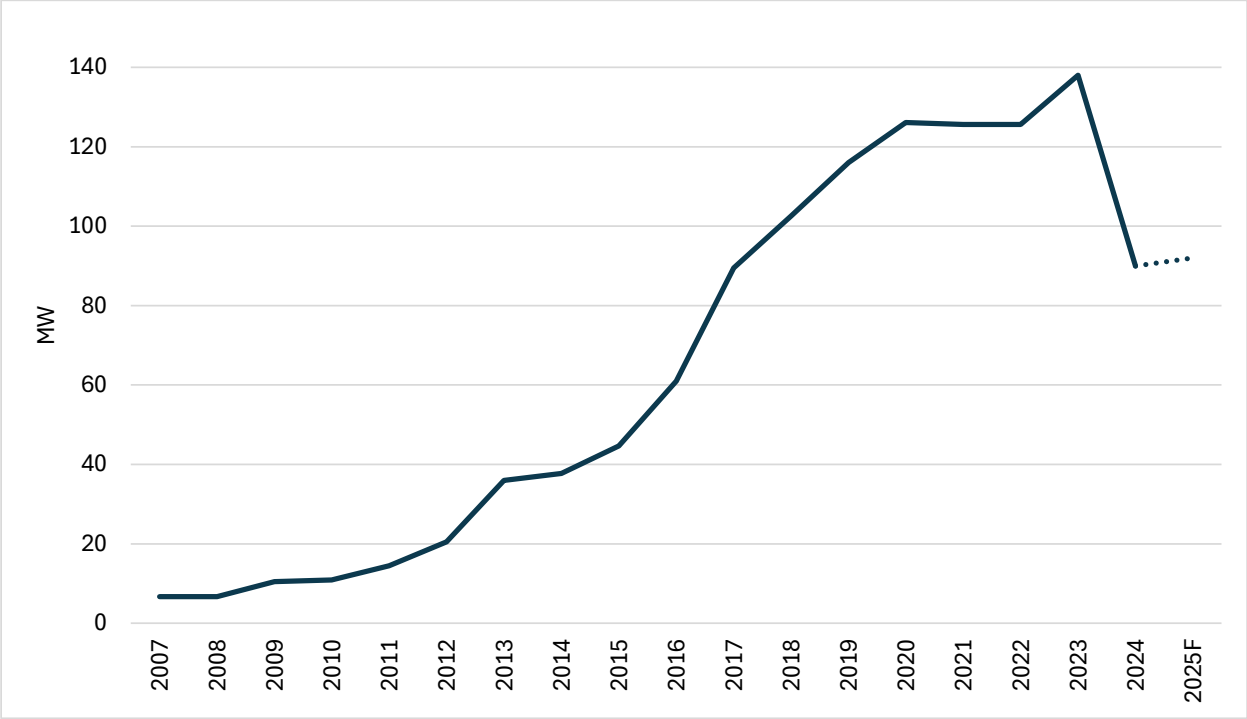
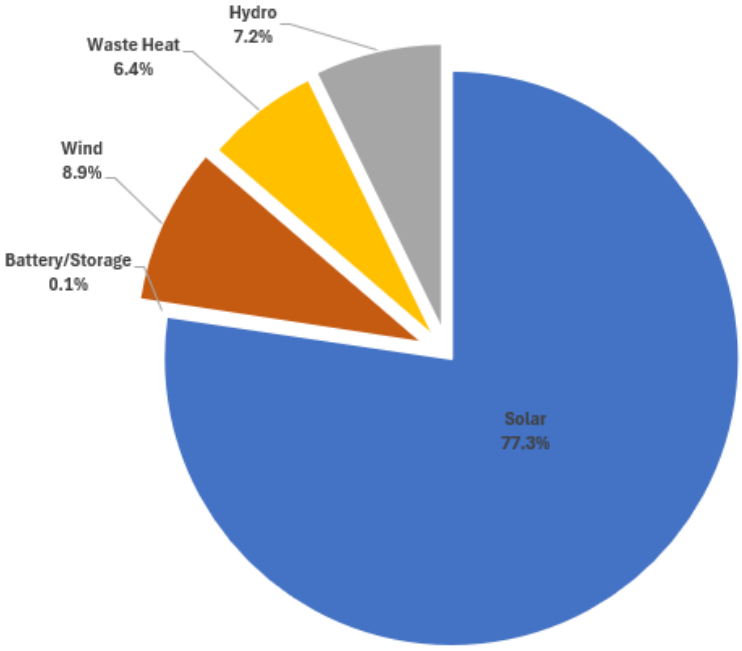


Figure 6 shows the breakdown of these projects by technology category. As of December 31, 2024, fifty-eight renewable or distribution generation projects totaling 90 MW were in operation across 20 Member Systems, with solar technology comprising over 77% of Member generation distributed resources.

FIGURE 6 – MEMBER BP 115 RENEWABLE AND DISTRIBUTED GENERATION PROJECTS BY TECHNOLOGY, NAMEPLATE CAPACITY OPERATING AS OF 12/31/2024



Bring Your Own Resource (BYOR)

Tri-State's BYOR program was accepted by FERC on August 2, 2025. Within this program Utility Members can bring forth resources equivalent up to 40% of their peak capacity needs through their owned or controlled projects, with Tri-State supporting all Utility Members by integrating BYOR projects into its multi-state system. BYOR allows Utility Members to have additional flexibility to develop resources under their Wholesale Electric Service Contracts with Tri-State, while not increasing wholesale rates or shifting costs between Utility Members. All load served under the BYOR resources remains Class A load.

Energy Efficiency

In 2024, Tri-State's long-standing energy efficiency program spent a total of $5.8 million on incentives in support of energy efficiency and certain electrification programs (not including administrative costs associated with this program). The programs delivered 56,133 MWh of first-year savings in Colorado, and an estimated 322,612 MWh of lifetime energy savings resulting from 2024 efficiency installations. Annual and cumulative savings from the program through 2024, including the removal of all items that have reached their established end of useful life, are shown in Figure 7 below.

FIGURE 7 – TRI-STATE 2024 ENERGY EFFICIENCY MEASURES AND SAVINGS, CUMULATIVE AND ANNUAL

Cummulative

Category	Typical Measures	kW Savings	kWh Savings
Agricultural	Irrigation Motors Variable Speed Drive Retrofits	13,065	22,226,468
C&I HVAC	Air Source and Ground Source Heat Pumps	3,471	2,716,881
C&I Lighting	LED Lighting Street & Parking Lot Lighting Refrigerated Case Doors	47,229	175,876,342
C&I Motors	Variable Speed Drive Retrofits and Process Measures	9,403	48,493,751
Residential HVAC	Air Conditioners Air Source and Ground Source Heat Pumps	50,255	42,700,554
Residential - Other	LED Lamps, Energy Star Appliances Electric Water Heaters Low Income Weatherization	54,728	30,597,885
Total		**178,151**	**322,611,881**

Annual Savings

Category	Typical Measures	kW Savings	kWh Savings
Agricultural	Irrigation Motors Variable Speed Drive Retrofits	738	1,175,175
C&I HVAC	Air Source and Ground Source Heat Pumps	139	447,190
C&I Lighting	LED Lighting Street & Parking Lot Lighting Refrigerated Case Doors	1,294	4,938,378
Industrial	Process Measures	3,076	36,674,828
Residential HVAC	Air Conditioners Air Source and Ground Source Heat Pumps	5,086	11,187,795
Residential - Other	LED Lamps, Energy Star Appliances Electric Water Heaters Low Income Weatherization	1,127	1,710,328
Total		**11,459**	**56,133,693**

On September 1, 2022, Tri-State submitted its 2023/24 Colorado Demand-Side Management ("DSM") Plan, informationally, in Proceeding No. 20A-0528E. The DSM Plan describes Tri-State energy efficiency programs and its plans to scale programs to meet energy savings targets agreed upon in the 2020 ERP Settlement Agreement ("Colorado EE Targets"), which began in 2023.

By the end of 2024, Tri-State met its second Colorado EE Target.

2024 Colorado EE Target		2024 Colorado EE Achievement	
0.50%	45.6 GWh	0.61%	56.6 GWh

The programs that contributed most significantly to the 2024 EE Target included: Air-Source Heat Pumps for Space Conditioning, Commercial Lighting, Oil and Gas, and Commercial and Industrial ("C&I") savings.

Tri-State anticipates meeting its 2025 Colorado EE Target due to growth in oil and gas ("O&G") sector energy efficiency projects. As of October 2025, Tri-State's EE program savings is 36.1 GWh or 60.1% of the 2025 Tri-State's goal of 60.04 GWh (0.75% of Colorado Member load). Tri-State held informational DSM Roundtable Meetings with interested stakeholders on June 17, 2025 and November 12, 2025.

Demand Response

Tri-State is committed to the development of in-house demand response ("DR") programs designed to meet the target of 4% of Colorado peak load under control in 2025 ("2025 Colorado DR Target").[18]

2025 Colorado DR Target	
4%	59.5 MW

Tri-State's Demand Response Rider was accepted by the Federal Energy Regulatory Commission ("FERC") effective May 2025.[19] Following FERC acceptance, Tri-State's DR programs became available to the entirety of the Tri-State Utility Membership in late May 2025, subject to Tri-State and relevant vendor implementation resources. These programs include:

- Irrigation Load Control
- Commercial & Industrial Load Control

[18] 2020 ERP Phase I Settlement Agreement, section 3.11.8. states: "Tri-State will either conduct an RFP for demand response prior to submitting its next ERP or develop in-house demand response offerings in Colorado by 2025 that are designed to control at least 4% of Tri-State's Colorado peak load."

[19] Docket No. ER25-1733.

- Smart Thermostats
- Member Battery Energy Storage

Between 2026 and 2029, Tri-State will continue to evaluate additional program concepts to support reaching the 2030 Colorado DR Target,[20] including but not limited to water heater controls, electric vehicle charging, and distribution-scale virtual power plants.

In 2025, Tri-State worked with its contracted partner, OATI, to implement a new Distributed Energy Resource Management System ("DERMS") which is a platform that enables event scheduling, DR and Distributed Energy Resource ("DER") integration and dispatch, DR/DER meter data analysis, and reporting. Most facets of the OATI DERMS are now operational for Tri-State users, with development resources now focused on Member system integrations. Tenants of the OATI DERMS platform will be made available to participating Utility Members, subject to terms and conditions of the Demand Response programs. Additionally, Tri-State has partnered with an outside consultant to assist with program design recommendations, in collaboration with Utility Members.

As of November 2025, the total DR capacity enrolled is 40 MW; in addition, approximately 45 battery assets are slated for enrollment once associated funding is released and will join the DR program at that time. Through the remainder of the year, Tri-State is working with Utility Members to continue to implement DERMS tenants and enroll additional C&I, residential and irrigation load, as well as battery storage resources. Tri-State informed stakeholders of its delay in implementing the DR program, and provided an update on the new DR Rider, during the June 17, 2025 DSM Roundtable Meeting.

7. Update on Emissions Reductions

In January 2022, Tri-State filed a Settlement Agreement with numerous parties to its 2020 Phase I ERP. Emissions reductions were among the many topics addressed through the Settlement Agreement. Tri-State agreed to emissions reduction targets for Tri-State's wholesale sales of electricity in Colorado, with respect to Tri-State's APCD-verified 2005 Baseline, as follows:

[20] 2023 ERP Phase I Settlement Agreement, section 4.9.1 states: "Tri-State will aim to control at least 5.5% of Tri State's Colorado peak load through demand response programs by 2030."

TABLE 3 – GHG EMISSIONS REDUCTION TARGETS[21]

Year	Percentage GHG Emissions Reduction
2025	26%
2026	36%
2027	46%
2030	80%

Tri-State also committed to including the following information in its APRs in each year following a year shown in Table 3:[22]

- The amount of GHG emissions, in tons, related to Tri-State's wholesale sales of electricity in Colorado for the prior calendar year, as reported by Tri-State to the Colorado Air Quality Control Commission under Regulation 22; and
- The percentage reduction in GHG emissions related to Tri-State's wholesale sales of electricity in Colorado for the prior calendar year, computed using the CEP Guidance and the 2005 Baseline. The percentage reduction will be consistent with the tonnages that Tri-State reports under Regulation 22.
- Information on how the emission rate for unspecified energy purchases specified by the CEP Guidance differed from the actual annual reported emissions rate for those purchases. Tri-State also will provide information as to whether any adjustments in operations or resource acquisitions are needed in order to ensure Tri-State meets the targets.

Tri-State will begin reporting this information in its December 2026 APR, for the 2025 GHG emissions reduction target.

As of October 31, 2025, Tri-State is forecasting a ~31% reduction in greenhouse gas (GHG) emissions from energy serving its Colorado load, from a 2005 baseline; the 2025 target is a 26% reduction,[23] making Tri-State on-target toward achieving its first Colorado emissions reduction milestone.

[21] Section 3.3.4. of the Settlement Agreement filed in Proceeding No. 20A-0528E.
[22] Section 3.3.11. of the Settlement Agreement filed in Proceeding No. 20A-0528E.
[23] Section 3.3.4. of the Settlement Agreement filed in Proceeding No. 20A-0528E.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-90:
Colorado Commission Decision No. C25-0612

Decision No. C25-0612

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 23A-0585E

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

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

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

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I. BY THE COMMISSION

A. Statement

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

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

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

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

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

B. Discussion

1. Electric Resource Planning for Tri-State

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

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

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

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

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

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

2. Phase I Procedural Background

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

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

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

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

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

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

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

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

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

C. Tri-State's ERP Implementation Report

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

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

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

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

17. The six modeled portfolios include:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

D. Independent Evaluator Report

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

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

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

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

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

E. APCD ERP Verification Report

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

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

F. Phase II Party Comments

1. Staff

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

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

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

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

2. UCA

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

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

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

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

3. CEO

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

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

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

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

4. Moffat County and City of Craig

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

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

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

5. San Isabel and KC Electric

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

6. Wyoming Cooperatives

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

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

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

7. Conservation Coalition

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

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

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

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

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

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

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

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

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

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

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

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

8. WRA

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

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

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

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

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

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

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

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

9. CIEA

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

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

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

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

10. COSSA

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

G. Phase II Public Comments

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

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

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

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

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

H. Tri-State's Response to Party Comments

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

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

[61] Comments Ridgeway Mayor, San Miguel County Geothermal Support, San Miguel Power Association - Geothermal.
[62] Tri-State Response Comments, p. 6
[63] Tri-State Response Comments, p. 14.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

I. Tri-State's CPCN Motion

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

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

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

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

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

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

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

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

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

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

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

2. Tri-State's Response

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

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

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

3. COSSA/SEIA Response

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

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

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

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

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

K. Discussion, Findings, and Conclusions

1. Cost Effective Resource Plan

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

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

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

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

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

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

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

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

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

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

2. Best Value Employment Metrics

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

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

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

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

3. Motion for CPCN Waivers

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

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

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

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

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

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

4. Phase II Motion of Conservation Coalition and WRA

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

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

[91] Interim Decision, ¶ 24, p. 9.

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

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

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

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

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

5. Future Proceeding Prior to 2027 ERP

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

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

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

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

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

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

6. Craig Units Not Needed for Reliability

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

116. We agree with Conservation Coalition Conservation Coalition that Craig Unit 1 is not required for reliability or resource adequacy purposes based on the record in this ERP. Every portfolio that Tri-State modeled assumes that Craig Unit 1 retires at the end of 2025 and does not provide any energy or capacity after 2025. At the same time, Tri-State convincingly concludes that every portfolio meets all reliability metrics and is reliable.

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

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

II. ORDER

A. The Commission Orders That:

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

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

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

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

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

6. This Decision is effective upon its Issued Date.

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

(S E A L)

ATTEST: A TRUE COPY

Rebecca E. White,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

ERIC BLANK

MEGAN M. GILMAN

TOM PLANT

Commissioners

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

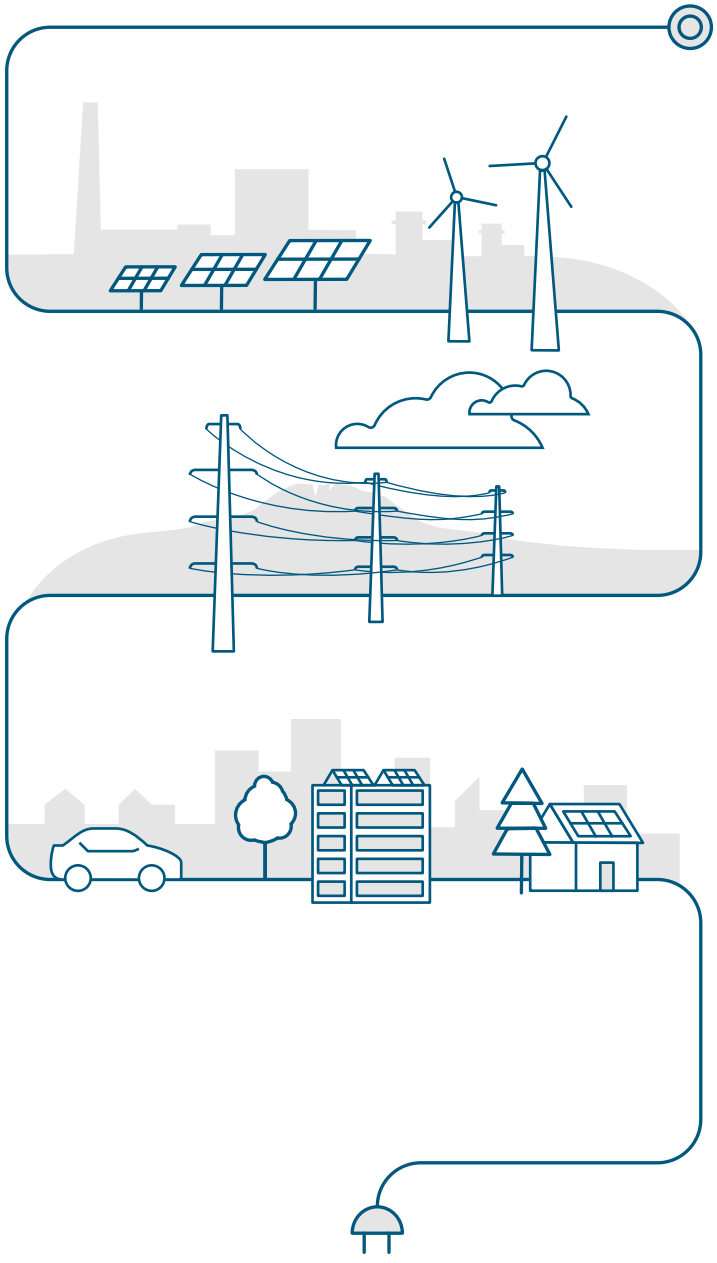
Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-91:
Platte River 2020 IRP

Platte River Power Authority

Estes Park • Fort Collins • Longmont • Loveland



2020 Integrated Resource Plan

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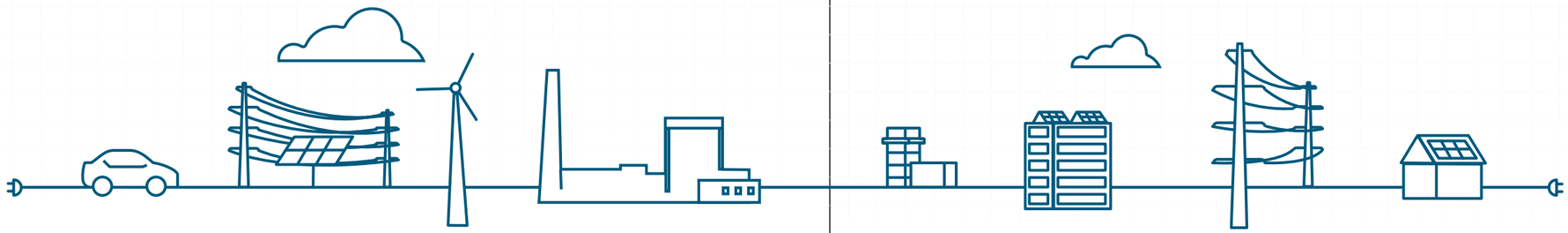
Executive summary



Platte River Power Authority (or Platte River) is pleased to present its 2020 Integrated Resource Plan (or IRP). This IRP builds on the significant progress made by Platte River by adding or committing to almost 400 MW noncarbon generation in 2020. This plan presents a potential roadmap to progressing toward the Resource Diversification Policy goal of a 100% noncarbon resource mix. This policy was adopted by Platte River's Board of Directors (board) in 2018 to proactively work toward the goal of achieving a 100% noncarbon resource mix by 2030 while maintaining three pillars of safely providing reliable, environmentally responsible and financially sustainable energy and services. When adopting this policy, the board also recognized certain caveats related to technology evolution and market development.

This IRP used the best available information today to develop four resource mix portfolios spanning a wide range of future possibilities.

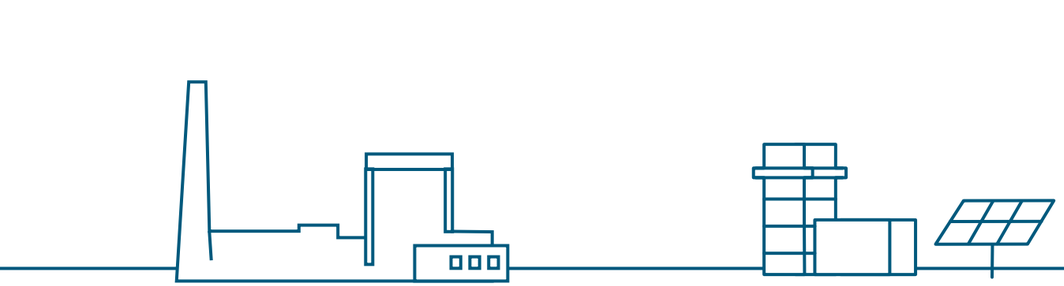
Each of these portfolios is a 20-year plan starting in 2021, integrating both demand-side and supply-side resources to reliably meet the owner communities' electricity needs in a least cost manner. This IRP should be viewed as the continuation of Platte River's journey toward achieving the goal of a 100% noncarbon resource mix, in line with the direction of the board and the goals of Platte River's owner communities of Estes Park, Fort Collins, Longmont and Loveland. The key value proposition of this IRP is the directional view it provides for future decisions.

An IRP is a snapshot of a future path based on the assumptions at a particular point in time (summer/fall 2019 in this case), but the planning is a dynamic process whereby the plans are updated as technology evolves and other assumed variables change. This IRP was developed prior to the COVID-19 impact on electricity demand. While the short term impact at the time of writing this document is 5-7% demand reduction, long term impact is hard to predict. Platte River will update its long term electricity demand forecast and modify supply plans according to the changes brought about by this pandemic in future power supply plans.

Platte River is not required to complete its next IRP until 2021 but several recent developments necessitated accelerating the process. First and foremost is the board's adoption of the Resource Diversification Policy. Second, considerable investments in renewable energy have been made, including the 225 MW Roundhouse Wind Energy Project, the 22 MW Rawhide Prairie Solar project that came online in 2020 and the 50-150 MW of solar being finalized for commercial operation in 2023. Finally, Platte River has committed to join the Western Energy Imbalance Market (WEIM), which will enable Platte River and its regional partners to integrate renewable energy resources more efficiently. Together, these changes require Platte River to re-evaluate and update its long-range plan.

Development of this IRP relies on several assumptions and forecasts made by staff and studies conducted by outside consultants. On the demand side, these assumptions include forecasts for anticipated energy consumption and the level of distributed energy resources (DERs), mainly distributed solar, electric vehicles (EVs) and energy efficiency penetration. On the supply side, the main assumptions include: forecasts of natural gas, coal, and electricity market prices; CO_2 price; costs for new thermal resources; costs for new renewable resources; and the cost of battery storage. Out of these assumptions, the level of DER penetration and the costs of renewables, battery storage, natural gas and the CO_2 are key drivers of the IRP results. Platte River designed the following four portfolios and sensitivities to test variations in these drivers.

Major components of the four portfolios

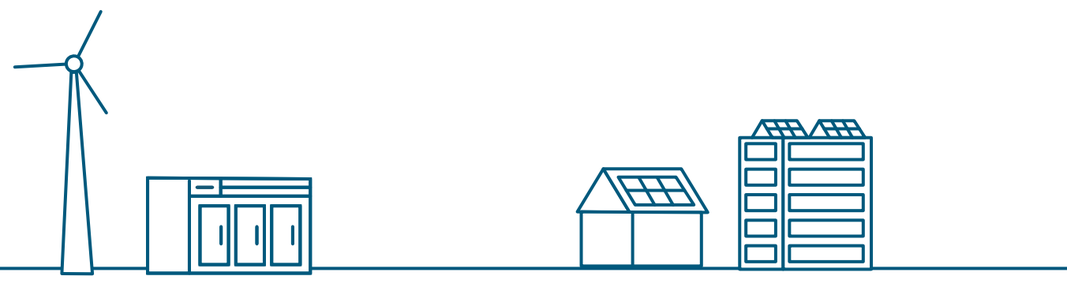


Portfolio 1: continuity

Portfolio 1 (P1) explores continuing the current path of reliably meeting owner communities' load obligations while adding new resources or retiring existing resources only when economical. Following the announcement of plans to retire coal-fired Rawhide Unit 1 by 2030, the key assumption of no forced retirements has been superseded in this portfolio. However, this portfolio provides a valuable baseline to compare costs and CO_2 emissions with the other portfolios.

Portfolio 2: zero coal

Portfolio 2 (P2) explores the path where Platte River retires all its coal fired generation by 2030 while continuing to reliably meet the owner communities' load obligations by adding new resources economically and continuing to meet or exceed all environmental regulations. The recent announcement of plans to retire Rawhide Unit 1 by 2030 aligns well with this portfolio.



Portfolio 3: zero carbon

Portfolio 3 (P3) explores the path where Platte River retires all of its thermal generation by 2030 while continuing to meet the owner communities' load obligations by adding only noncarbon resources and battery storage.

Portfolio 4: integrated utilities

Portfolio 4 (P4) explores the path where the drivers of current industry transition evolve at an accelerated pace to manifest a faster energy transition. For example, the costs of solar, wind and battery technologies in this portfolio are 15-25% lower, and distributed solar and EV adoption rate is two times faster relative to other portfolios. During this rapid industry transition, Platte River would continue to meet the owner communities' load obligations while adding new resources or retiring existing resources economically.

Outreach and engagement

14
Community engagement sessions

600
Approximate community participants

100+
Emails received from stakeholders

2
Scientific surveys

Platte River staff developed the four portfolio options and this IRP with significant input from regional leaders, stakeholder organizations and the public from the owner communities, then conducted greater outreach once the portfolios were determined. Engagement occurred through digital and traditional media, community listening sessions, scientific surveys and focus group meetings conducted by Colorado State University's (CSU) Center for Public Deliberation (CPD).

Engagement between staff, Platte River's Board of Directors, stakeholders and the public came to a halt in mid-March due to health concerns associated with the COVID-19 pandemic. Not wishing to allow any hinderance to stakeholder or public input, the board delayed formal presentation of any action on the IRP until board meetings could allow for public comment.

Visit prpa.org/irp to view results from the listening sessions, focus groups and scientific surveys

Summary results

The four IRP portfolios were analyzed using Aurora model (Appendix D), a resource planning tool commonly used by U.S. utilities to identify a least-cost combination of resources that meets the constraints of the portfolio. Reliability measures, costs and emissions were tracked for all the portfolios and formed the basis of relative comparison between them.

Each portfolio was first evaluated to ensure its reliability. Portfolios containing thermal resources that can be dispatched to meet load satisfy standard utility reliability metrics. For portfolios relying on 100% renewable resources, there are no industry standards or guidelines for the optimal level of installed capacity that can provide acceptable level of reliability. A given level of battery, wind and solar capacity may be reliable for one particular wind and solar profile but unreliable for another. Staff developed a resource mix to provide a reasonable level of reliability based on the past few years of wind and solar profiles. This level of resources may not be sufficient for a future wind profile with long periods of low output of both wind and solar generation. Some additional reliability may be gained from an energy market but reliance on market purchases during times of low solar and wind output is speculative. Given these facts, the reliability of the zero carbon portfolio at this time is uncertain.

Wholesale rates and CO_2 emission reductions were used to benchmark the financial and environmental performance of each portfolio. Figure 1-1 shows projected wholesale rates for the four portfolios and Figure 1-2 shows the percent of CO_2 reduction relative to 2005 emissions.

It is clear that the wholesale rates for P3 are much higher than other portfolios. P3 rates rise at an annual rate of 9% vs. 2-3% for the other portfolios during 2021-2030. This is due to the high level of investments to procure large quantities of renewables and battery storage needed to provide 100% renewable energy.

Figure 1-2 shows CO_2 reductions for the four portfolios relative to 2005 actual emissions. There is a steady increase in percent reduction from 20% in 2021 to over 40% by 2029. This doubling of reduction is achieved through the gradual retirement of Craig coal units and addition of renewable generation. After 2029, P1 does not achieve any significant reduction. P2 sees emission reduction of above 90% in 2030 and beyond following the retirement of Rawhide Unit 1. P3 achieves 100% reduction with the retirement of all thermal generation in 2030. P4 experiences a large increase in emission reduction in 2036 following the retirement of Rawhide Unit 1.

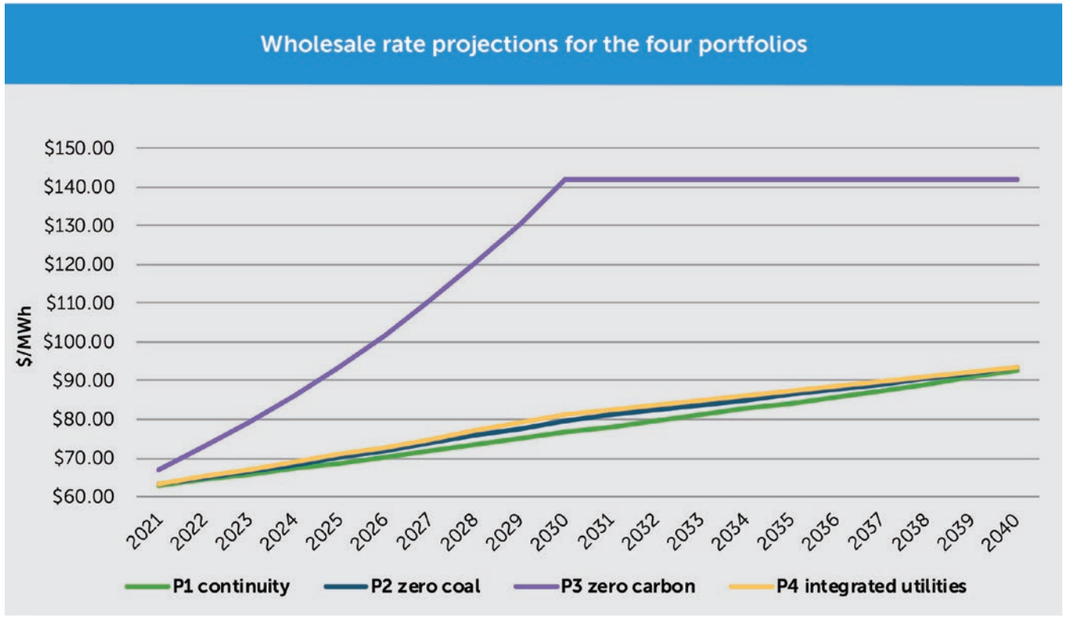


Figure 1-1

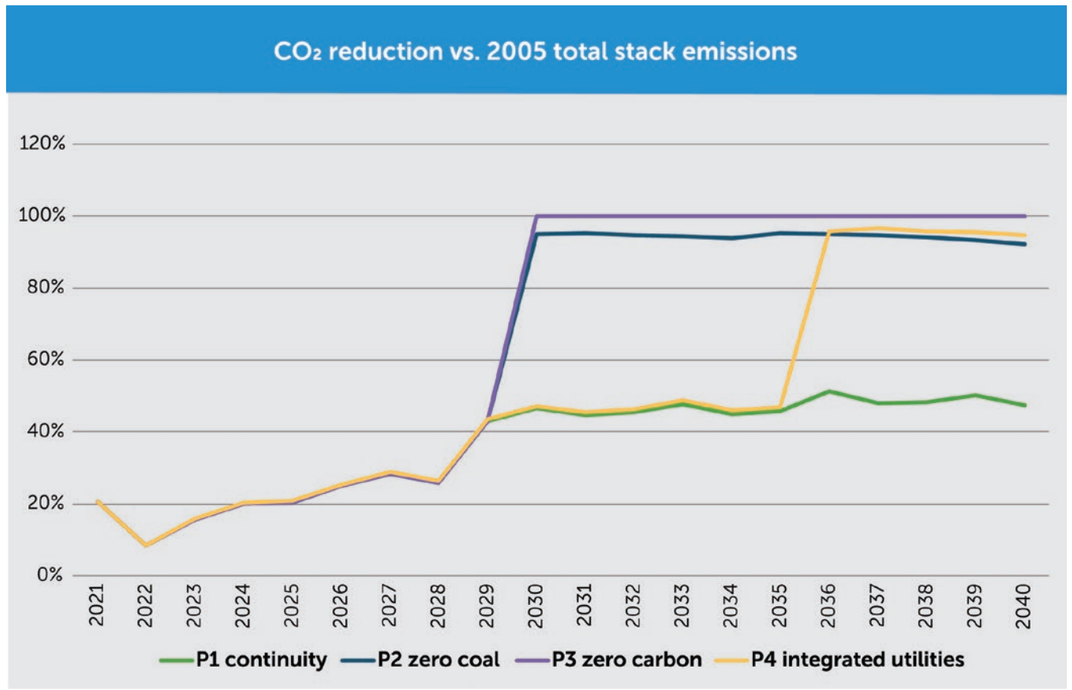


Figure 1-2

Key takeaways

- Platte River is making significant progress towards Resource Diversification Policy goals by adding almost 400 MW of renewables during 2020-2023 which will take the share of noncarbon energy to 60% of the owner community load.
- Portfolio decarbonization will continue with the planned retirements of coal generation in 2025, 2028 and 2030.
- This IRP presents four portfolios to cover wide ranging future possibilities through 2040.
- Following the announcement of Rawhide Unit 1 retirement in 2030, P1 and P4 do not represent a viable future but still provide valuable information for comparison.
- P2 and P3 are aligned with the announcement of retiring coal assets, the Resource Diversification Policy and the state environmental legislation and regulation (SB19-236 and HB19-1261) allowing Platte River to voluntarily file a clean energy plan (CEP) which will show more than 80% reduction in CO_2 in 2030 relative to the actual emissions in 2005.
- P3 has a significant rate impact and it may not fully meet the reliability requirements of the owner communities.
- P2 is the least cost path to comply with the state environmental legislation and the Resource Diversification Policy while maintaining the three pillars of safely providing reliable, environmentally responsible and financially sustainable energy and services. **P2 is the staff recommended portfolio.**
- The role of new gas fired generation in P2 complements the intermittency of renewables and provides back up to guarantee a high level of reliability. Platte River will continue to evaluate technological breakthroughs (prior to making an investment decision) to determine if it can reasonably provide these services from noncarbon sources.
- Planning is a dynamic process. Staff will continue to refine the recommended portfolio with new data and assumptions focusing on evaluating battery storage and DERs to maintain reliability as well as firming up timing, type and size of new resources to replace retiring coal. New resources will be brought online throughout this decade and operational expertise developed prior to retiring Rawhide Unit 1 in 2030. This is critical to ensure a smooth transition to a renewable heavy supply mix with a high level of reliability.
- This IRP is a possible roadmap for the future and not a firm investment plan. Platte River staff is committed to modifying plans to align with the direction of the board and the goals of the owner communities as demonstrated by Platte River's track record since filing the last IRP. The 2016 IRP projected total renewable energy production of 400,000 MWh during 2021-24. With the renewable projects online and under firm commitment, Platte River will produce over 1 million MWh in 2021 and 1.4 million MWh in 2024 – over three times the projections included in the 2016 IRP.

2 Platte River Power Authority overview

History

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

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

Governance

Following the passage of 1975 legislation enabling municipalities to form power authorities, the four communities executed the organic contract establishing Platte River as a political subdivision of the state of Colorado. The organic contract is an agreement between the four owner communities that sets forth Platte River's purposes and governance structure.

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

Vision

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

Mission

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

Values

The following values tangibly define Platte River's daily commitment to following the vision and mission to strengthen the organization and improve the quality of life in the communities we serve.

Safety

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

Sustainability

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

Service

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

Operational excellence

We will strive for continuous improvement and superior performance in all we do.

Integrity

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

Innovation

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

Respect

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

3 IRP background

An IRP[1] is typically a 10- to 20-year plan developed by utilities to meet their customers' future electricity needs. An IRP optimally selects from demand- and supply-side resources while meeting the planning reserve margin (PRM[2]) criteria to ensure reliability of supply under all reasonable expectations of supply and demand that vary over time. An IRP only plans for wholesale generation and customer side DERs. It does not consider supply infrastructure like transmission and distribution systems unless needed for specific generation resource delivery. An important component of an IRP is an action plan that provides specific and detailed utility plans and activities during the next three to five years before developing the next IRP.

Utilities started developing IRPs during the 1980s in response to rising costs of nuclear generation and other fuels, and to include energy efficiency and other demand-side options in the supply mix. During the 1990s, with the onset of power sector restructuring and market development, IRPs became less valuable because markets were expected to drive optimal generation investments. Power markets have evolved more slowly than expected, however, with varying degrees of success for enabling generation investments across different parts of the country. With rapidly falling prices of renewable energy resources, battery storage and DERs, IRPs have again emerged as a vital planning tool for utilities. Major stakeholders including regulators, customers and utility decision makers now use IRPs to chart the future course of investment for utilities.

[1] In this document the acronym IRP is used in two different ways; an integrated resource plan or an integrated resource planning process

[2] PRM is defined as the additional generating capacity available to meet a future year peak demand. It is expressed as a percentage of peak demand. North American Electric Reliability Corporation generally advises utilities to maintain a 15% PRM which means if a utility is expecting a peak demand of 100 MW in a future year it must build or acquire 115 MW of generating capacity to reliably meet that peak demand.

3.1 Why do an IRP now?

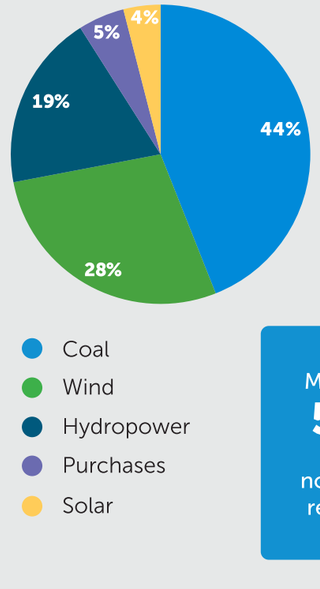
The electric utility industry is rapidly transforming by the three Ds:

1. De-carbonization
2. De-centralization
3. Digitalization

By 2021, Platte River will deliver more than 50% noncarbon energy to its owner communities, placing it as a leader of this historic transformation. This IRP is a continuation of the journey toward achieving a 100% noncarbon energy mix as enabling technologies develop over the next decade.

Platte River filed its last IRP in 2016. According to Western Area Power Administration (WAPA) requirements, the next IRP is not due until 2021. Platte River decided to accelerate the IRP development by one year to respond to its owner communities' desire for a lower carbon energy mix and rapidly declining prices for renewable resources. According to Lazard, an industry leader in power sector investments, the cost of solar has dropped at an average annual rate of 13% over the past five years while the cost of wind has dropped at an annual rate of 7% during the same period[3]. Battery storage costs have also seen rapid declines. Coupled with the falling costs of noncarbon resources, DERs and EVs are becoming more popular among the owner communities. With the vision to maintain Platte River's role as an industry leader and to respond to owner communities' strong desire for lower carbon power supply, the Platte River Board adopted a Resource Diversification Policy[4] in December 2018. The policy calls for a 100% noncarbon energy mix by 2030 provided the necessary technologies and regional markets evolve to ensure reliable and financially sustainable supplies. This IRP provides the beginning of a road map to achieve the noncarbon goals of Platte River's owner communities, its associated costs and expected reliability using the currently available technologies.

Projected deliveries of energy to owner communities in 2021



More than **50%** from noncarbon resources

[3] See Lazard report at https://www.lazard.com/perspective/lcoe2019

[4] See the Resource Diversification Policy on Platte River's website

3.2 Developments since the last IRP

Platte River has taken a leadership role in providing noncarbon energy to its owner communities. By 2021, Platte River will supply approximately 50% noncarbon energy to its owner communities due to successful execution of a strategy to capture market opportunities while focusing on the communities' goals for a fully noncarbon portfolio. With the addition of a 150 MW solar project under negotiations, the level of noncarbon energy is expected to reach 60% by 2024. The 2016 IRP projected total renewable energy production of 400,000 MWh during 2021-24. With the projects online and under firm commitment, Platte River will produce over 1 million MWh in 2021 and 1.4 million MWh in 2024 – more than three times the projections in the 2016 IRP.

Since filing the last IRP in 2016, Platte River's emergence as a leader in Colorado's utility sector is marked by:

2016

- Integrating **30 MW of solar generation** at the Rawhide Energy Station
- Signing an agreement to **retire** the coal-fired Craig Unit 1 by 2025
- Initiating a wholesale **demand response** pilot program
- Initiating a **commercial midstream cooling rebate program** to increase adoption of high efficiency packaged cooling equipment

2017

- Performing a **zero-net carbon study** to explore different paths and associated costs to provide additional noncarbon energy to the owner communities
- Initiating **income-qualified energy efficiency programs** in collaboration with the owner communities and Energy Outreach Colorado
- Evaluating participation with a **regional transmission organization**
- Starting operation under a **joint dispatch agreement** (JDA)

2018

- Signing a 20-year power purchase agreement (PPA) to buy wind energy from the **150 MW Roundhouse Renewable Energy Project**
- Adopting the **Resource Diversification Policy** that calls for a three-pronged approach to reach a 100% noncarbon energy mix by 2030
- Committing to develop and file an **IRP** earlier than WAPA requires
- Introducing the **Efficiency Works Store** to offer select energy-efficient products directly to customers and programs that provide efficiency assessments and efficiency project support for multifamily buildings
- Determining that Platte River's participation in an **energy imbalance market** serves its interests as a significant step toward participation in a full regional energy market
- Extending the **organic contract and power supply agreements** between Platte River and its owner communities to 2060
- Signing a contract for **22 MW of Rawhide Prairie Solar and 2 MWh of battery storage**
- Securing an **additional 75 MW of wind** capacity from the Roundhouse Renewable Energy Project
- Starting a request for proposal process to purchase **50 to 150 MW of additional solar** generating capacity
- Restructuring the **wholesale power supply rate** with the owner communities
- Initiating the collaborative process with the owner communities to develop a **DER strategy**

2019

- Beginning discussions with co-owners of the coal-fired Craig Unit 2 to **retire** it before 2030
- Achieving **100,000 MWh of cumulative energy savings** between 2016 and 2019 in collaboration with the owner communities – approximately 3% of overall load – by investing nearly $36 million in Efficiency Works™ programs
- Launching an **EV distributed charging study**
- Making the commitment to join the **WEIM** operated by the California Independent System Operator, with four other regional utilities

2020

- Announcing that Rawhide Unit 1 will cease producing electricity by 2030, 16 years before its planned retirement date
- Finalizing the decision with co-owners of Craig Unit 2 to retire the unit on Sept. 30, 2028
- The 225 MW Roundhouse Wind Energy Center beginning commercial operation

The aggressive agenda implemented since the 2016 IRP filing clearly reflects the intentions of Platte River's Board, the owner communities and the customers they serve. These activities demonstrate a fundamental shift from a traditional business model toward that of a modern energy provider while maintaining **Platte River's core pillars to safely provide reliable, environmentally responsible and financially sustainable energy and services to the owner communities**.

3.3 Resource Diversification Policy

Platte River's Board unanimously approved the Resource Diversification Policy in December 2018. This policy directs the general manager/CEO to proactively work toward the goal of reaching a 100% noncarbon resource mix by 2030 while maintaining Platte River's three pillars of providing reliable, environmentally responsible and financially sustainable energy and services.

To achieve this goal, the board recognized that the following conditions must be met:

- An organized regional market must exist with Platte River as an active participant
- Battery storage performance must mature, and the costs must decline
- Utilization of storage solutions to include thermal, heat, water and end user available storage
- Transmission and distribution infrastructure investment must be increased
- Transmission and distribution delivery systems must be more fully integrated
- Improved distributed generation resource performance
- Technology and capabilities of grid management systems must advance and improve
- Advanced capabilities and use of active end user management systems
- Generation, transmission and distribution rate structures must facilitate systems integration

This policy provided the framework for the 2020 IRP. Various components of this policy as applicable to the IRP are discussed here.

3.4 Efforts to join a market and development of JDA

In recent years, Platte River has made several attempts to join or form an energy market. Early attempts to join a market such as a regional transmission organization or independent system operator were not favorable due to relatively low-cost generation and relatively high-cost transmission in the region. Market operations typically allow more use of transmission to reduce variable production costs. Many transmission providers in the west were reluctant to forego transmission revenues and, with already-low variable costs, little benefit could be derived from market participation. However, with the ever-increasing penetration of variable energy resources such as wind and solar generation, establishing a regional market has become more compelling given the operational challenges that can arise with large amounts of intermittent generation. To better integrate renewable resources, Platte River now seeks a larger and more diverse market to help it meet long-term noncarbon energy goals.

Following several studies of potential markets, Platte River, Xcel Energy and Black Hills Energy began collaborating in late 2012 to develop the JDA concept, which would create a smaller scale and more regionally focused market option that allows for more efficient use of generating resources. Joint dispatch combines all or some portion of generating resources from the participating companies into a common portfolio for real-time optimization to serve each participant's individual load. The resulting market price associated with joint dispatch energy exchanged by participants for an hour is based on actual highest incremental generation costs during the hour.

The JDA functions like a small energy imbalance market where all participants are required to be balanced prior to entering the hour. After the hour starts, all participating units are dispatched up or down, based upon costs, to most economically serve each participant's load. The current JDA has limitations, however. It does not treat offline generation (even quick start) as available capacity, only performs hourly settlements and will not consider multi-hour dispatch for better system optimization. Nevertheless, the collaboration between Platte River, Xcel Energy and Black Hills Energy under the JDA has led to lower overall energy costs for the participants than if they served their own load using just their own resources.

Platte River was an active member in the Mountain West Transmission Group, which considered joining the Southwest Power Pool's Integrated Marketplace. In early 2018, the Mountain West Transmission Group members determined this option was not feasible. Platte River then began to study participation in other potential market options, including those offered by the Midwest Independent System Operator and by Pennsylvania, New Jersey, Maryland power pool (PJM)/Peak Reliability, as well as the WEIM and the possible formation of a new, stand-alone market. The PJM/Peak Reliability option was dismissed in April 2018 because Peak Reliability announced the discontinuation of its reliability coordinator services by the end of 2019.

Members of the JDA worked to enhance the JDA by attracting a new member – Colorado Springs Utilities – and, at the same time, study the benefits of taking a more manageable step toward an integrated market by joining an existing energy imbalance market. An energy imbalance market is a real-time market in which energy generation from multiple power providers is dispatched at the lowest possible cost to serve the combined customer demand of the region. During 2019, the JDA utilities commissioned the Brattle Group to study the WEIM, which is operated by the California Independent System Operator, and the Western Energy Imbalance Services proposed by the Southwest Power Pool. The study concluded that, as the larger of the two markets, the WEIM offers greater potential to lower production costs due to the size of its market footprint and the diverse resources available. The study also revealed WEIM offers lower administrative costs, and participants of the WEIM are exploring adding day-ahead market services. Day-ahead market services are designed to help utilities plan which resources they will use to generate energy, allowing more renewables to be integrated into the system. In late 2019, Platte River and its JDA partners announced they would join the WEIM. Participation in the WEIM is scheduled to start in 2022.

3.5 Studies conducted for 2020 IRP

The following nine studies were performed to support this IRP. A more detailed description of the studies is provided in Appendix A. All studies are available on the IRP microsite except for the market analysis, which provided data and assumptions for the IRP as discussed in Chapter 7.

1. Generation technology review
2. Regional economic impacts
3. Energy storage technology assessment
4. Coal cycling
5. Thermal generation alternatives
6. Resource adequacy review
7. Market analysis
8. DER potential
9. Life cycle carbon impact

3.6 Objectives of 2020 IRP

Platte River's 2020 IRP provides a 20-year plan designed to meet its owner communities' need for reliable, environmentally responsible and financially sustainable energy and services during the ongoing industry transition, by enhancing the share of renewable resources and DERs. The five-year action plan, incorporated within the IRP, offers a critical component of Platte River's long-range implementation plan to achieve the goals of the Resource Diversification Policy. Consequently, this IRP is anchored primarily by adding noncarbon resources and battery storage while exploring four different long-term energy mix options.

3.7 IRP modeling tool

Platte River used Aurora simulation and modeling tool for the 2020 IRP development. Aurora is an economic dispatch and capacity expansion model developed by Energy Exemplar (energyexemplar.com). More details about the Aurora model are provided in Appendix D.

4 Five-year action plan

This IRP can be seen as the continuation of Platte River's journey toward decarbonizing its portfolio. This journey started almost two decades ago and reached a watershed moment with the board's adoption of the Resource Diversification Policy in 2018. Following this policy adoption, Platte River made some major renewable resource additions that will enable it to supply more than 50% noncarbon energy to its owner communities after the startup of the 225 MW Roundhouse wind project in 2020. During the next five years, this journey of progressive decarbonization will continue with a focus on efficiently integrating the Roundhouse wind and 50-150 MW solar project under solicitation. Additionally, the next five-year action plan will also include efficient integration into the WEIM, preparation for Craig Unit 1 retirement and other activities discussed in this chapter. This action plan will be reviewed on an annual basis as existing projects are completed and new ones are added.

4.1 Roundhouse integration

Platte River added 225 MW of Roundhouse wind energy capacity to its energy mix during the summer of 2020, which is expected to provide about one fourth of our communities' load. Integrating this much intermittent wind energy with existing resources will be a major focus of the operations group within Platte River. Benefits of this large wind resource will be maximized by integrating it with the dispatch of thermal resources.

4.2 Rawhide Prairie Solar and battery storage integration

The Rawhide Prairie 22 MW solar and 2 MWh battery project is expected to start commercial operation during the later part of 2020. As intermittent renewable resources continue to take a larger share of Platte River's supply portfolio, battery storage will play a more crucial role. Platte River's staff will test and study the operation of a 2 MWh battery installed within the Rawhide Prairie Solar project. Experience gained with the control, optimization and operating cost of the storage will be valuable when adding more storage to prepare for thermal resource retirements.

4.3 New solar project completion and integration

Ensuring the on-time permitting, construction and integration of the new 150 MW solar project will be another focus area for Platte River staff. When this solar project comes online in 2023, about 60% of the energy delivered to Platte River's owner communities will come from noncarbon energy resources on an annual basis.

4.4 Western Energy Imbalance Market

Platte River operations and planning staff will be working with stakeholders, including other market participants and the market operator, to integrate into the WEIM by 2022. Integration into the WEIM is expected to improve system reliability and lower operational cost through greater access to a wider and more diversified resource mix in the region.

4.5 Rawhide coal flexibility enhancement

The coal-fired Rawhide Unit 1 was designed to run as a baseload unit and has performed very well in this role. With more and more intermittent renewable generation joining the supply mix, Unit 1 will need to be more flexible to follow the ever-changing load and renewable supply. By changing its operating practices, Platte River has reduced Unit 1's minimum generation level from 140 MW to 100 MW. Over the next few years, Platte River staff will test even lower generation levels and more load following operations. Platte River's goal is to enhance Unit 1's flexibility without compromising reliability or incurring excessive operations and maintenance costs.

4.6 Craig coal retirement readiness

The coal-fired Craig Unit 1 will be retired by 2025 and the Craig Unit 2 will retire by September 2028. Retirement of Craig coal units will bring Platte River closer to the goal of 100% noncarbon resources. With the renewable resources already procured, Platte River can offset the loss of the energy generated by Craig Unit 1 by 2025. However, the replacement of 77 MW of firm capacity (more than 10% of the peak demand in 2019) with intermittent renewables will need to be managed from operational and risk management perspectives, possibly with more batteries or more renewable resources.

4.7 DER strategy development and execution

Platte River and its owner communities are working on a comprehensive strategy for implementing DERs in a cost-effective manner. With a formal strategy in place, Platte River will work with its owner communities to start the implementation process. Existing energy efficiency programs, distributed solar, EV charging and beneficial electrification programs will be merged under this umbrella with new DERs.

5 Community engagement

As a community owned utility, Platte River engages the public in all its major initiatives. During the IRP process, Platte River increased public outreach and engagement efforts to obtain as much public input as possible.

A high level of public input was sought through the following initiatives:

- Multiple rounds of community listening sessions within the owner communities of Estes Park, Fort Collins, Longmont and Loveland
- Focus group meetings within the owner communities
- An IRP microsite and a dedicated email address; using digital technologies to not only inform audiences but also collect more input
- Formal customer surveys
- Stakeholder engagement

5.1 Community listening sessions

Platte River conducted three rounds of community listening sessions and a series of public focus group meetings. During the listening sessions, participants took part in surveys and provided direct input to Platte River leaders regarding future energy options.

Objectives of the listening sessions:

- October-November 2018: Inform the public about the IRP process and plans, and seek their input for different topics and areas to be covered in detail during the plan development process
- October 2019: Update the public on the IRP process and share results from nine independent studies conducted by Platte River to form the analytical basis of the IRP
- Fall 2020: Public presentations to inform stakeholders of Platte River's final IRP

Platte River promoted participation for each round of listening sessions via the news media, IRP microsite, email, word-of-mouth and social media channels. Approximately 50 individuals attended each of the events, for about 200 total participants per round of listening sessions. Local community activists attended each event, along with business and other community leaders. Platte River streamed each of the listening sessions live from its Facebook page, with viewers able to submit questions to panelists, then posted the recording of each on the IRP microsite.

5.2 Focus group meetings

The series of focus group sessions managed by CSU and CPD sought to increase diversity of participation and capture in-depth discussion and opinions concerning Platte River's IRP and the four energy portfolio options. Platte River and the CPD collaborated on outreach and promotion to draw participants to the focus group meetings. Participants received background information on Platte River's four portfolios. Participants discussed advantages and costs/risks associated with each alternative and provided opinions regarding Platte River's direction. The CPD assimilated all data and provided a report to Platte River's leadership, which was published on the IRP microsite. Due to the impact of COVID-19 and the need to curtail public gatherings, the Fort Collins event was canceled but replaced by an online focus group survey, which was built by the CPD to ensure input from Fort Collins customers.

5.3 IRP microsite

Key to the public transparency was the development of a microsite (**prpa.org/irp**), attached to Platte River's website, which contained all available information concerning the 2020 IRP including:

- General description of the IRP and its process
- Frequently asked questions
- Schedule of activities during the process
- Contact information and method to provide digital feedback
- Video recordings of all community listening sessions
- Key documents and research papers
- Results from formal community surveys

The IRP microsite quickly became the central location for stakeholder engagement. Analytics indicate visitors to the site remained on its pages up to five times longer than visitors to other Platte River web pages.

In addition to the microsite, a dedicated email address (**irp2020@prpa.org**) was set up to receive public input on IRP related issues.

5.4 Formal customer surveys

To obtain opinions about future energy resources from a representative cross section of customers, Platte River engaged a third-party research organization to conduct statistically valid surveys among residential and business customers in the four owner communities. Inside Information, a nationally recognized research agency with extensive utility experience, conducted surveys at the beginning of the IRP process and during public deliberation over the four energy portfolio options.

Inside Information conducted two studies within each owner community, one focused on residential opinions and the other on commercial business. Respondents were contacted randomly based upon customer lists provided by each of the owner communities and asked to respond to a series of questions posed in an online survey form. Inside Information followed up with phone surveys within each community until a statistically valid set of responses was obtained from both residential and commercial business audiences.

Platte River posted a series of reports containing survey results on its IRP microsite. The results of the first residential survey have a margin of error of +/-2.9% at a 95% degree of probability. That means for any given statistic, there is a 95% chance that the result does not vary by more than 2.9% in the actual total population. The results of the commercial survey have a slightly larger margin of error of at +/-3.4%.

A second round of surveys was conducted in the spring of 2020 to coincide with the focus group sessions managed by the CPD. Questions posed paralleled those asked during the focus groups, again providing a statistically valid series of responses from a diverse cross-section of customers within Platte River's service territory. Results of the second round of surveys were posted on the IRP microsite.

5.5 Inquiries and input

Anyone with any interest or opinion regarding Platte River and its IRP was encouraged to make inquiries or provide their thoughts through several means, including by mail, phone, email or social media. Contact methods were made available through the IRP microsite. The largest percentage of comments were taken by email through a simple portal from the microsite. Several individual comments or inquiries were received during the process. A nationwide stakeholder group, through its local chapter, deployed a digital software program that enabled its members to send a standardized message (along with limited ability to provide personal thoughts) to Platte River. IRP managers received approximately 100 of the automated notes.

5.6 Stakeholder outreach

Platte River provided a significant amount of information to key groups including board members, the news media, community utility leaders and communications staff to enhance public outreach and engagement. Board members frequently made public remarks about the IRP process and invited the public to attend listening sessions. Plans for community listening sessions were made public well in advance of each event and forwarded to key stakeholders to maximize outreach. The news media provided significant coverage as well, in advance of and following community listening sessions.

5.7 Stakeholder engagement

Platte River also met with several stakeholder organizations during the IRP process, to provide background and key information that may pertain to their interests. Stakeholders included business, government and environmental organizations.

The Northern Colorado Partners for Clean Energy (NCP4CE) is a coalition of organizations in the four communities that own Platte River. NCP4CE is also a member of the Colorado Coalition for a Livable Climate but retains autonomy regarding its work with Platte River and all local initiatives. Platte River conducted five detailed sessions with NCP4CE including conference calls and in-person meetings.

The meetings were conducted on:

- Feb. 14, 2019
- May 28, 2019
- Aug. 16, 2019
- Nov. 12, 2019
- Dec. 19, 2019

Platte River incorporated many suggestions from these public engagements, such as the estimation of CO_2 impact of methane leakage during natural gas production and transportation, and inclusion of the social cost of carbon as an incentive to reduce carbon emissions.

Platte River representatives also engaged with chambers of commerce within the owner communities, presenting background and key information about the IRP. Meetings with local, state and federal elected officials took place on an individual basis and presentations were made to city councils.

5.8 Public engagement outcome and results

Platte River received direct input from between 2,000 and 3,000 residential and commercial business customers during the two-year outreach and engagement process, through community listening sessions, formal surveys and electronic and hard-copy communications with the IRP team. Thousands more were made aware of the IRP process and its issues through digital communications and news media coverage.

Public input was primarily aligned with Platte River's three core pillars of system reliability, environmental responsibility and financial sustainability. Those expressing opinions generally supported the aggressive pursuit of renewable energy resources toward the goal of achieving a 100% noncarbon energy mix. Participants were not willing to sacrifice system reliability and most participants expressed only mild interest in spending more than what was otherwise necessary for quality electric service in pursuit of that goal.

Public engagement came to a halt in mid-March 2020 due to health concerns associated with the COVID-19 pandemic that was rapidly spreading through Colorado, as it was across the nation. During its March board meeting, which was conducted virtually, the board delayed formal presentation and action on the IRP until the public could provide input during its board meetings.

6 IRP demand-side assumptions

Traditionally, customer electricity needs consisted solely of aggregate electricity demand. With the growth of DER, today's customer demand must also include a seamless and economic integration of these resources. This chapter covers methodologies and assumptions for customer load and DER projections.

6.1 Load forecast

The future load forecast is the main driver and a key input for the 2020 IRP. Historically, utility load forecasts were driven by economic activity and efficiency improvements. While these are still the primary drivers, distributed resources are rapidly becoming a significant contributor to future electricity demand, two of which will have the greatest immediate impact on future Platte River load: distributed solar and EV charging. Distributed solar includes behind-the-meter or distribution level solar resources. EVs include new demand for vehicle charging at the customer's home or public locations.

These two DERs will impact future Platte River load in opposite ways. Distributed solar will reduce the overall load while EV charging will increase it. Current penetrations of distributed solar and EV charging are low, so very little historical data exists to predict future loads, but the impact of these DERs will be significant. As a result, projected load related to these two resources was forecasted independently and added to the overall load. Other sources of new load, such as beneficial electrification (converting home heating and water heating from gas to electric) are in early stages of penetration and were not included as a separate load growth item in the forecast. Beneficial electrification could emerge as a significant source of demand for Platte River, but there is very little data to support any meaningful contribution to electricity demand at this time. This will likely be an area of focus in the next IRP.

This load forecast was developed prior to the COVID-19 impact on electricity demand. While the short-term impact at the time of writing this document is 5-7% demand reduction, the long-term impact is hard to predict. Platte River will update its load forecast and adopt supply plans according to the changes brought about by this pandemic.

6.2 Load forecast methodology

Platte River's IRP model requires monthly peak and overall energy forecasts for future planning and optimization. Forecasting methodology meets this requirement as discussed below.

To forecast monthly peak demand and energy, Platte River uses an autoregressive integrated moving average (ARIMA) time series model.

The ARIMA models are extremely flexible and are widely used for time series forecasting. The model developed for Platte River's load forecast accounts for seasonal changes in energy usage as well as a trend that captures increased efficiency and conservation by end-use customers.

6.3 Forecast drivers

Past loads can be explained by temperature, population and changes in air conditioning penetration. During the 1990s and early 2000s, for example, there was a warming trend in degree days and population growth reached a range of 2.5% - 4% annually. Most homes built to meet new housing demand included central air conditioning, while existing homes did not. The combination of warmer temperatures, relatively high population growth and increased penetration of central air conditioning led to high load growth. Since then, temperatures have moderated and population growth (with commensurate air conditioning installations) has slowed.

These factors combined with increased energy conservation practices have resulted in minimal load growth. Figures 6-1 and 6-2 show historical growth patterns for annual energy and peak demand.

In addition to these drivers, future loads are expected to be significantly impacted by the growth of distributed solar and EVs, which were estimated outside of the load forecasting model and added to the aggregate load. Logistic growth curves were used to estimate the capacity of distributed solar installations on the system and the number of EVs in Platte River's service territory.

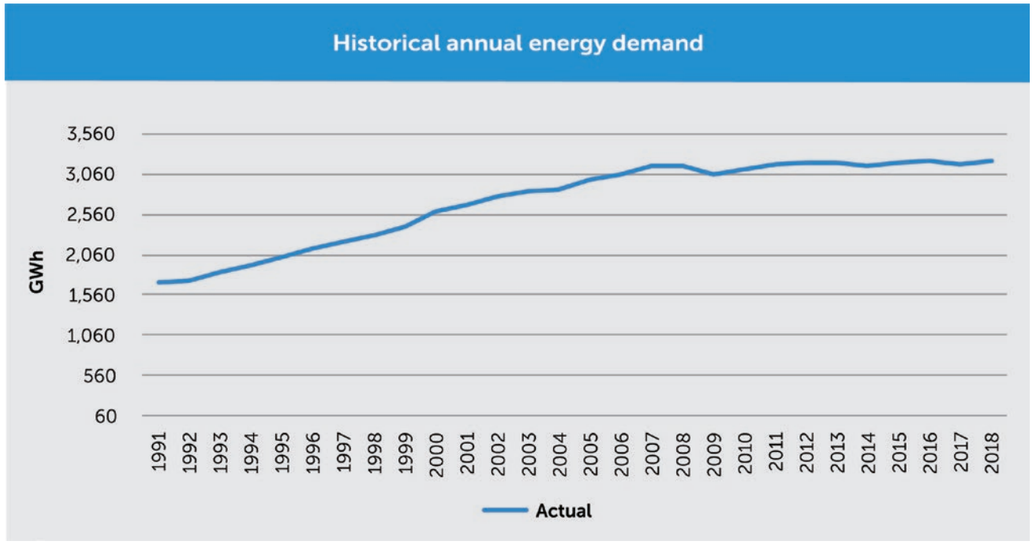


Figure 6-1

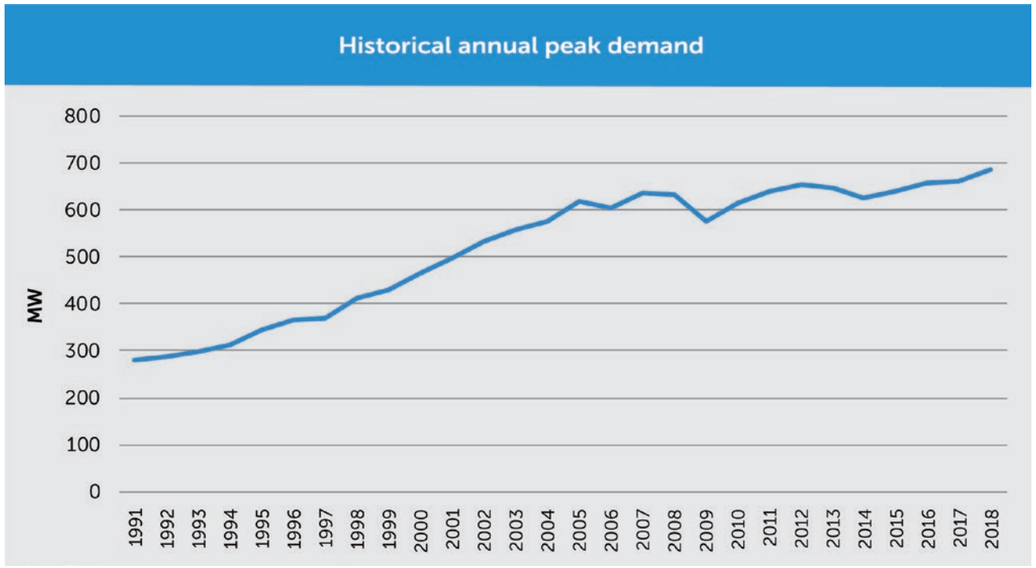


Figure 6-2

6.3.1 Degree days

As noted above, temperature influences energy demand and overall consumption, particularly during summer months when customers rely on air conditioning to maintain indoor comfort. Platte River's forecasting model uses total degree days per month[5] with no distinction made between cooling degree days and heating degree days. A negative value is associated with a heating degree day and a positive value is associated with a cooling degree day. The resulting sinusoidal curve enables a forecast providing nearly identical information to the separate measurement of heating degree days and cooling degree days but does so in one measure, thus reducing overall model complexity.

A trend and seasonal pattern are evident in historical degree day data beginning in the early 1980s. A simple linear regression was used to model the trend and seasonal pattern as well as to generate a forecast of degree days that is incorporated into the load forecasts. See Figure 6-3.

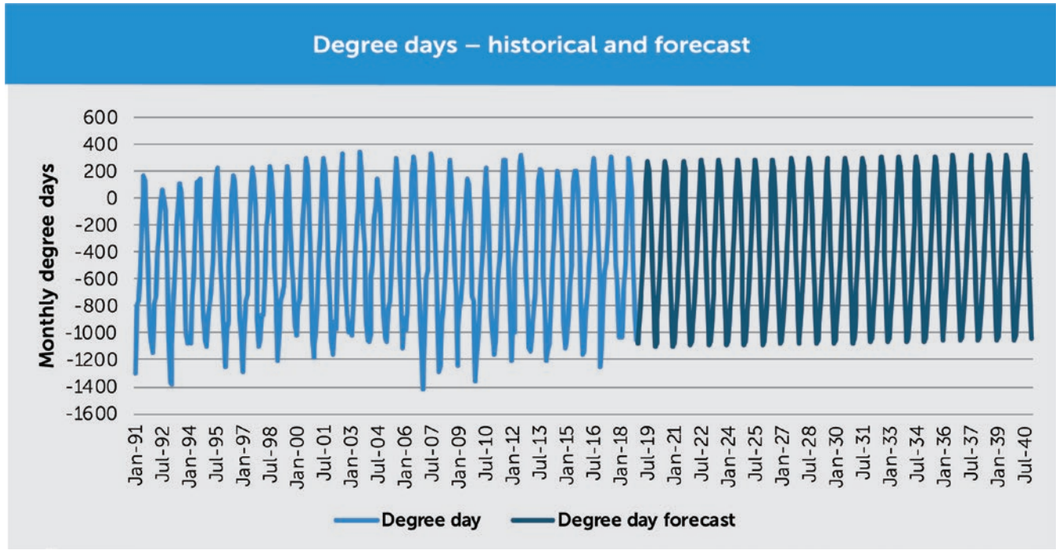


Figure 6-3

[5] Total degree days per month is calculated as the sum of (max temp + min temp)/2 – 65 for each day over a month. Thus, positive values reflect cooling degree days and negative values reflect heating degree days.

6.3.2 Population

Population growth is a key driver for load forecast. Data from the Colorado Department of Local Affairs demography office[6] shows population growth rates before the early 2000s were, on average, higher than growth rates after. The state demographer's office forecasts a declining rate of growth for the Fort Collins (FC) metropolitan statistical area (MSA) which covers the northeastern Colorado area and includes major load centers within Platte River service territory. Reduced land availability for northern Front Range development is one driver for the declining growth as shown in Figure 6-4. As a result, the increase in electricity demand attributable to new growth will likely decline in the future.

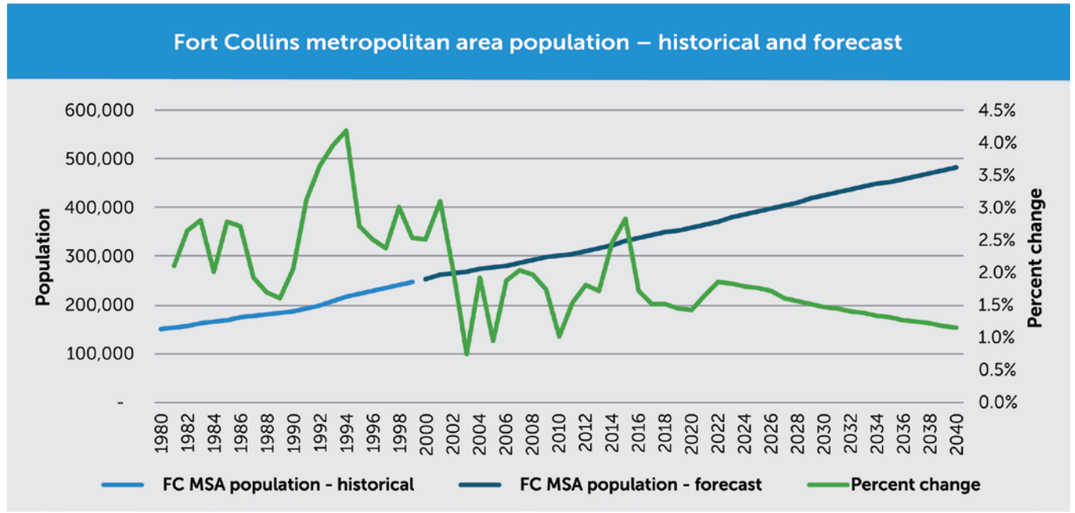


Figure 6-4

[6] https://demography.dola.colorado.gov/population/

6.3.3 Single-family homes, window to central air conditioning conversion

The annual penetration rates of central air conditioning (AC) in the single-family housing stock measures changes in how electricity is used by customers to cool their homes as well as other changes in the housing stock and the overall economic activity in the region. For example, the rate of AC penetration growth was higher before the financial crisis in 2008 than afterward, reflecting the growth in new single-family homes with central AC. After the financial crisis, the penetration growth rate slowed due to a shift away from new single-family housing construction to multifamily housing. Based on Larimer and Boulder County property records, approximately 25% of single-family homes had central AC units in 1980 compared to approximately 50% in 2018. This structural change has altered Platte River's demand dynamics from a winter peaking to summer peaking system.

The penetration rates for central AC flatten out from 2007 through 2010, reflecting a slowdown in the construction of new homes due to the national recession that occurred during this time. After 2010, penetration rates began to grow again but at a slower rate. The rate change stemmed from a change in the composition of new housing stock, with multi-family housing comprising a larger portion of new units.

Platte River estimated future penetration rates using a logistic curve, adjusted to match the growth seen in recent years, and assuming a maximum penetration rate of 85% because costs for installing AC in some older housing stock may be prohibitive. Due to this factor, the projection calls for single-family AC penetration rates to continue rising but at lower levels on a year-over-year basis as shown in Figure 6-5. This projection, in turn, reduces Platte River's load growth forecasts.

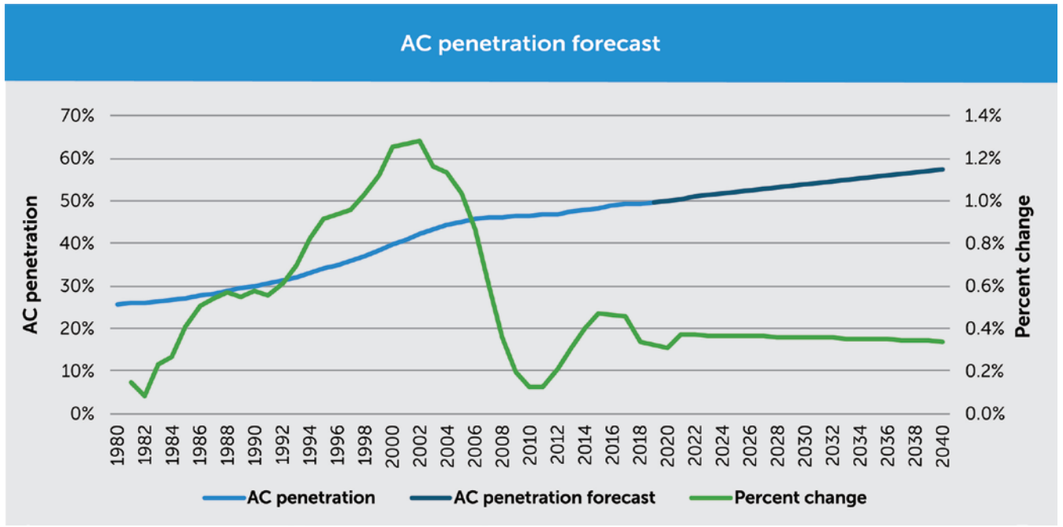


Figure 6-5

6.3.4 Distributed solar

A hosting capacity study performed by Fort Collins was used in developing an upper limit of 100 MW of distributed solar for Platte River's service territory without requiring additional investment in the distribution system. Staff used a logistic curve to develop a growth pattern from the historical actual level to the forecasted upper limit by 2030. Based on these assumptions, year-over-year growth in distributed solar capacity will likely increase until 2025 followed by a lower growth rate until the system reaches its hosting capacity in the early 2030s. The near-term high growth in distributed solar will partially offset new demand from population growth and contribute to lower growth in Platte River's wholesale energy sales to its owner communities. The projected growth of distributed solar is shown in Figure 6-6.

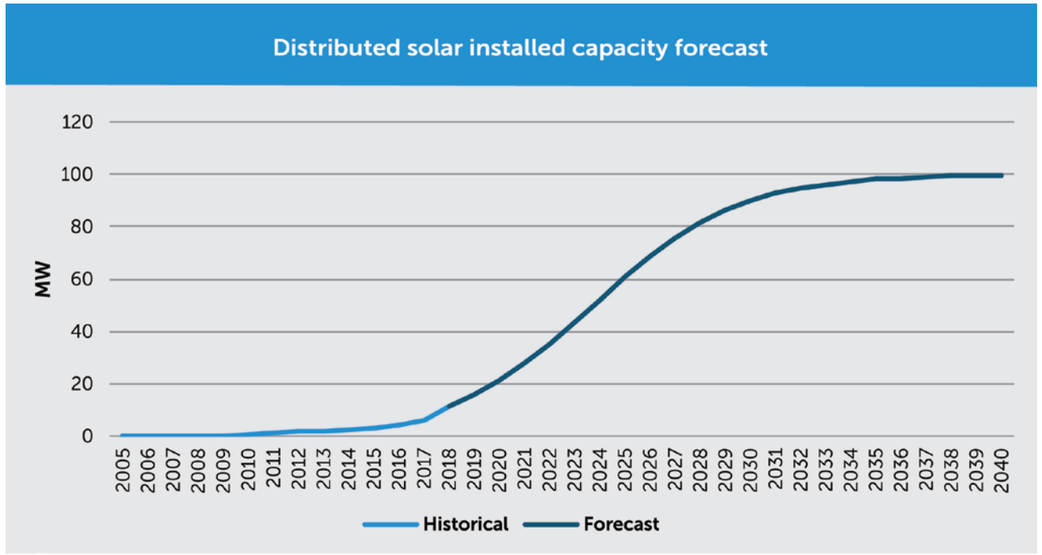


Figure 6-6

6.3.5 EVs

The penetration of EVs within the transportation sector will increase in northern Colorado, with energy consumption from charging influencing the Platte River system. A study conducted by BCS Inc. for the Colorado Energy Office[7] provided three forecasts for EV stock through the year 2030: low, medium and high growth scenarios. Platte River's projections used the medium scenario as it is consistent with observed data. Figure 6-7 shows a forecast of total number of EVs in our service area. By 2040, Platte River projects EV charging will reach approximately 10% of overall annual energy consumption as shown in Figure 6-8.

It is assumed that a very small fraction of the total EVs charge at the time of peak, therefore, the peak demand increase due to EVs is small as shown in Figure 6-9.

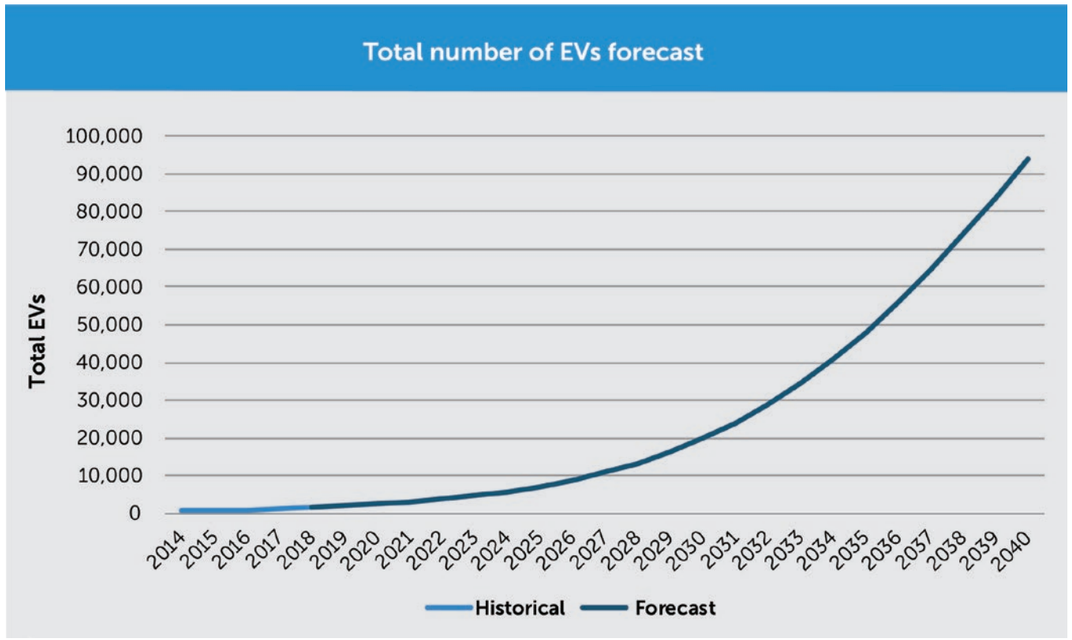


Figure 6-7

[7] https://www.colorado.gov/pacific/sites/default/files/atoms/files/EV%20Market%20Study%202015_0.pdf

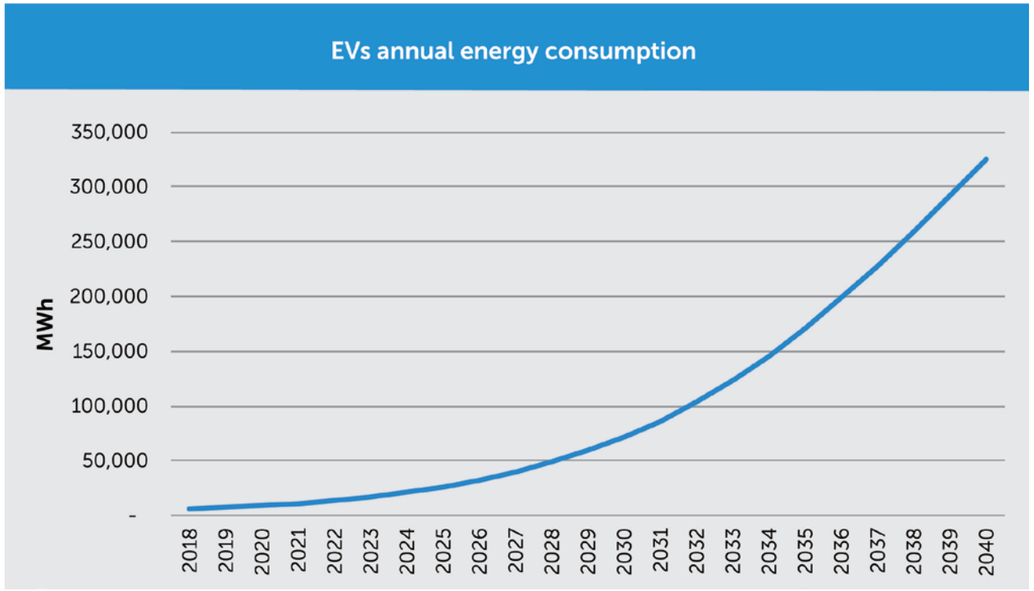


Figure 6-8

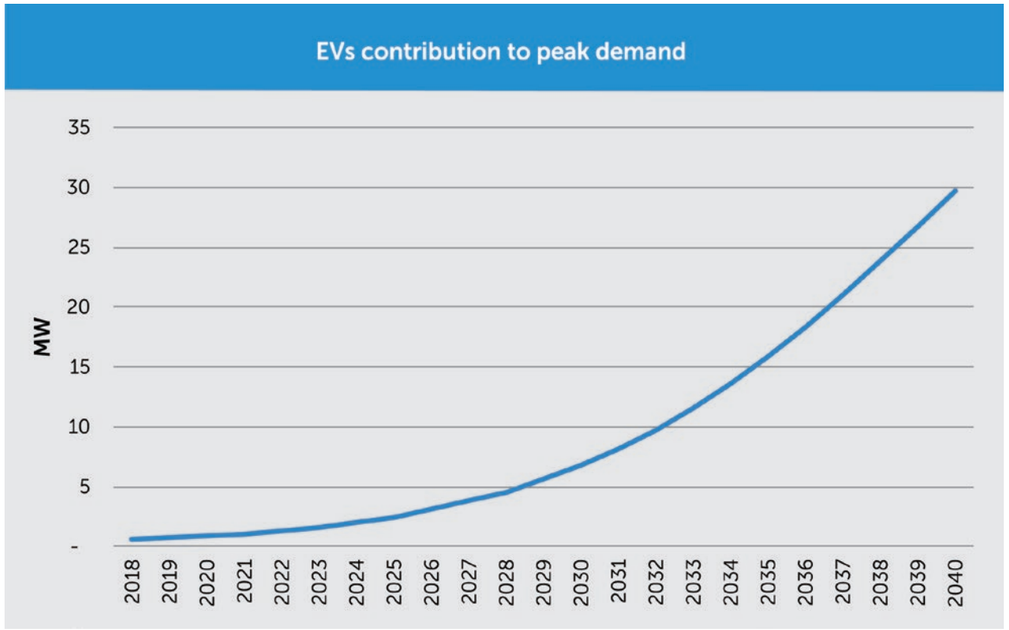


Figure 6-9

6.4 Energy efficiency/conservation trend

The forecasting model includes a trend to capture improvements in energy efficiency and conservation. For more than 10 years, annual residential energy use in Fort Collins, Longmont and Loveland trended downward, like the nationwide trend. Figure 6-10 shows annual average household energy consumption for the U.S. and three of Platte River's owner communities (no independent data available for Estes Park). Reasons for this decline include; technology improvements, regulatory changes and updated building code.

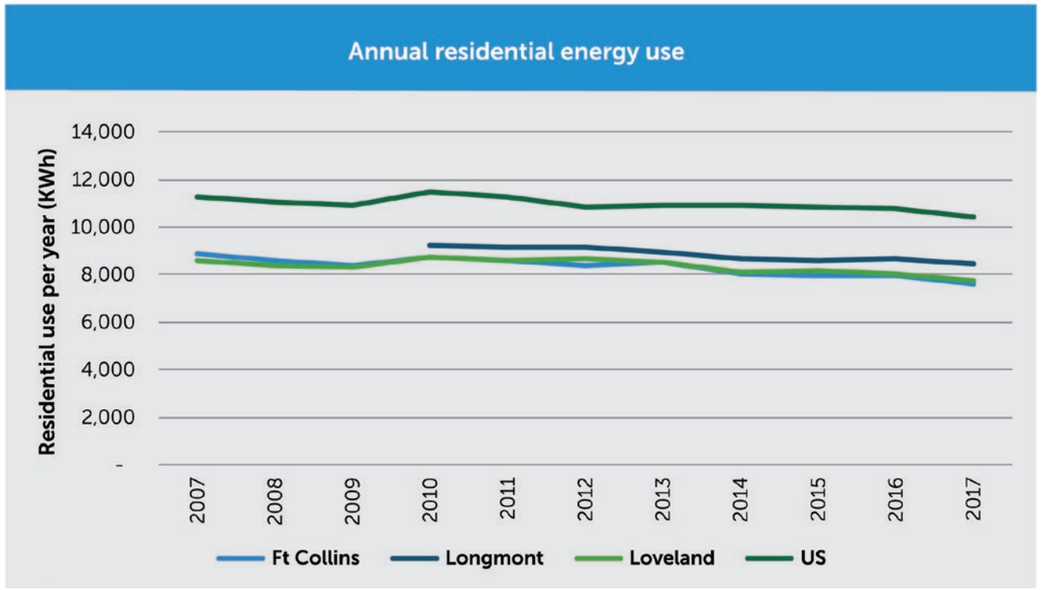


Figure 6-10

6.5 Load forecast

Platte River developed load forecasts with 70% and 90% confidence intervals to show the possible range of future growth. The confidence intervals only include a general forecasting error and do not include changes in forecast drivers, such as high or low EV penetration rates. The annual energy forecast with upper and lower confidence intervals is shown in Figure 6-11.

The annual peak demand forecast with 70% and 90% confidence intervals is shown in Figure 6-12.

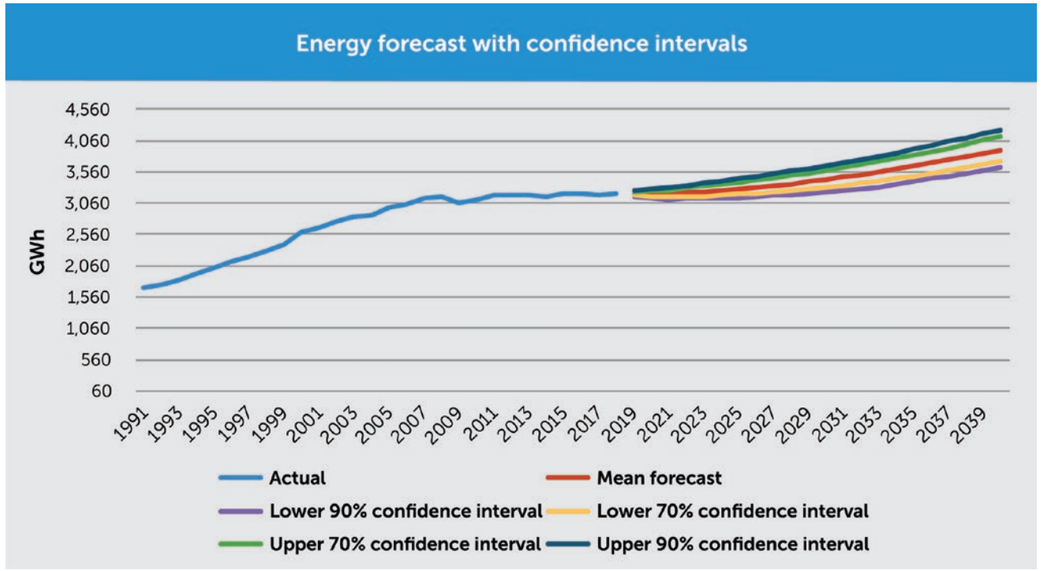


Figure 6-11

Figure 6-12

6.6 DERs

Historically, electric utilities defined "demand-side management" products and programs to include energy efficiency and demand response programs. However, this term is no longer adequate to describe the range of options and approaches available to utilities and their customers. Utilities increasingly define these approaches as DERs, which include any technologies, programs or resources implemented on the distribution system or within a customer's premise, whether in front of or behind the retail meter.

This includes energy efficiency, demand response, distributed generation, distributed solar, distributed energy storage and beneficial electrification.

Platte River seeks to integrate DER options or programs into its portfolio when they support Platte River's three pillars. Elements of DER that influence current load forecasting are discussed above but a more detailed discussion of existing and future DER programs is provided below.

6.7 Existing DER programs and activities

Platte River closely collaborates with its owner communities to evaluate, design and implement DER programs. This collaboration is important for three reasons:

1. DERs are located within the owner communities' distribution systems or within their customers' facilities
2. Potential benefits are shared between Platte River and the owner communities' electric systems
3. Implementation of DER programs often benefit from the economies of scale that come from collaboration among the owner communities

In addition to the collaborative initiatives described here, owner communities offer DER programs independently from Platte River based on their individually determined values, policies or goals. Those programs are not included in Platte River's resource portfolio but are included to the extent they affect Platte River's current load and future load forecast. Platte River and its owner communities have made significant investments in energy efficiency programs and will pursue other resources as technologies evolve, as customer interest in these technologies increase and as the electric system needs change. A brief discussion of existing DERs follows below.

6.7.1 Energy efficiency

Energy efficiency programs focus on helping customers reduce their energy consumption through a variety of interventions including outreach, education and incentives. Platte River and the owner communities deliver a growing portfolio of energy efficiency programs offered under the Efficiency Works brand, which are jointly funded and administered by Platte River and its owner communities. These programs provide communities with a cost-effective way to manage load growth, reduce carbon emissions and help customers reduce electricity costs.

Since 2002, Platte River and its owner communities have invested nearly $70 million in energy efficiency programs, serving thousands of residential and commercial customers by providing efficiency assessments, efficiency advice and rebates for efficiency improvements. In addition to these investments, customers have invested approximately $100 million to implement efficiency improvement measures. Figure 6-13 shows historical investments in energy efficiency programs while Figures 6-14 and 6-15 show associated energy and peak demand savings since 2002. Over this time, energy efficiency programs have achieved annual energy and demand savings of 251,000 MWh and 39.1 MW, respectively. Staff have assumed a finite lifetime for savings from the programs and retire the savings when the estimated lifetime is exceeded. As a result, these programs are currently estimated to have reduced Platte River's load by 206,000 MWh in annual energy consumption and 31.9 MW of demand. Investment in efficiency resources are cost effective compared to the cost of supply-side resources otherwise needed.

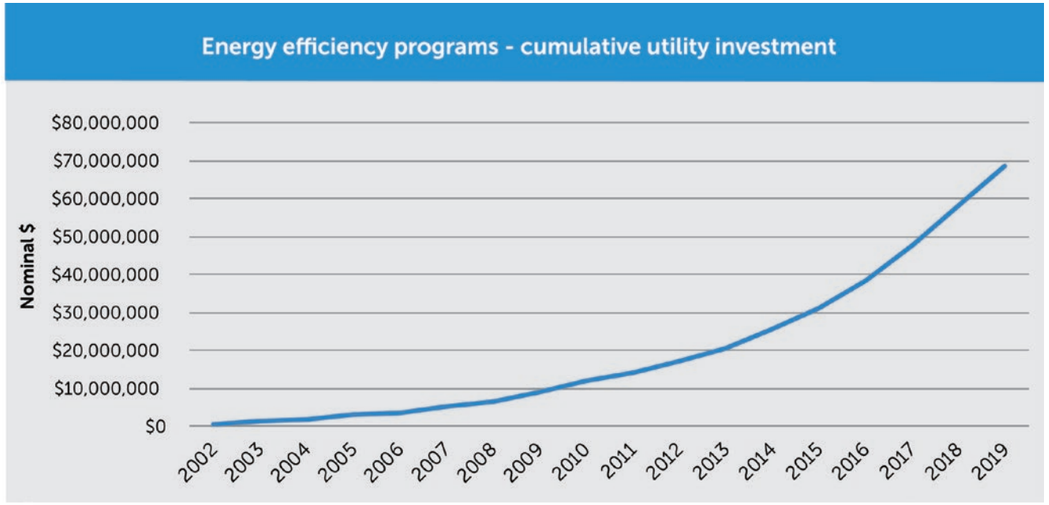


Figure 6-13

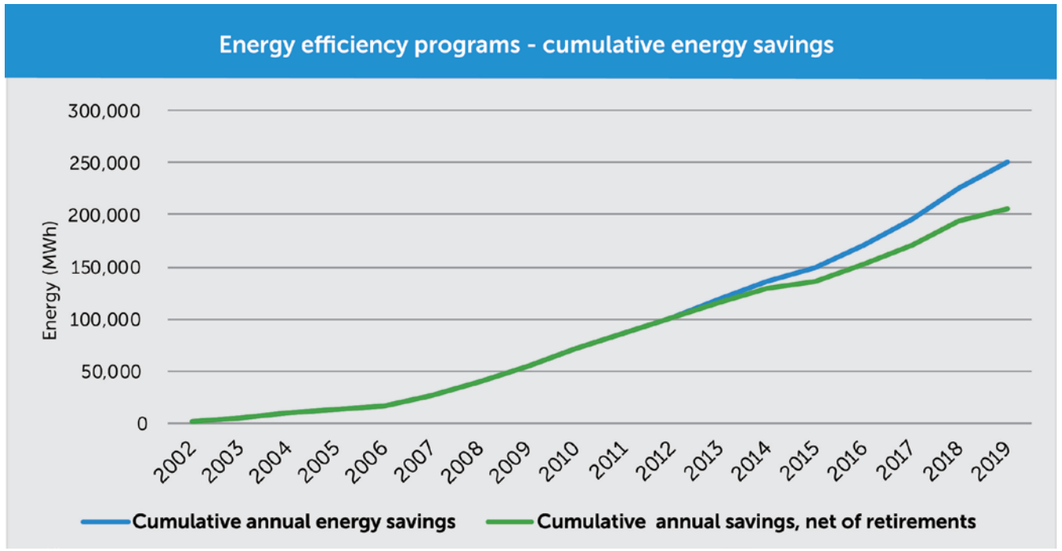


Figure 6-14

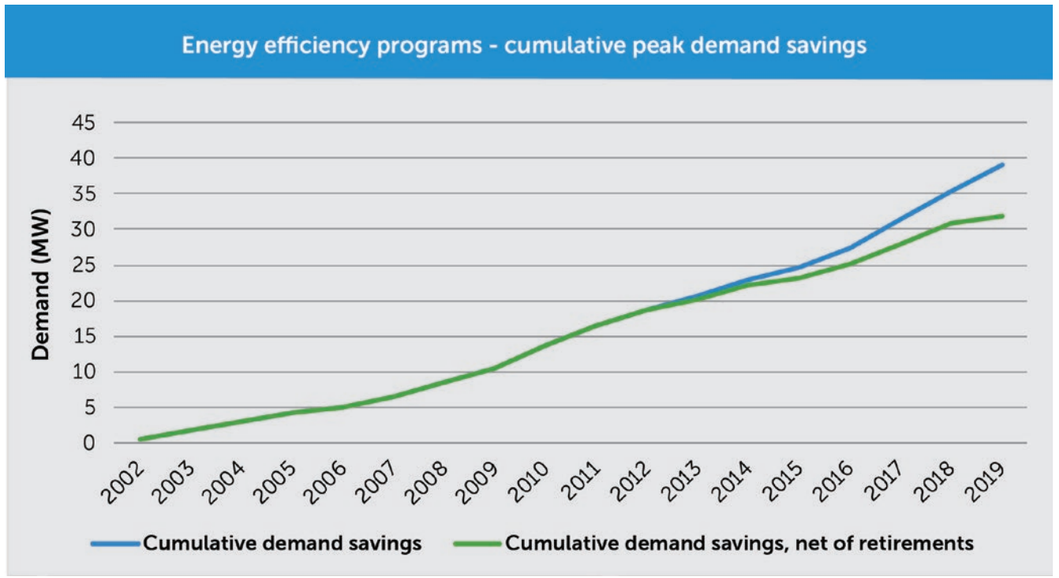


Figure 6-15

6.7.2 Demand response

Demand response programs incentivize customers to shift energy use from times of high demand or high cost to the periods of low demand or low cost. Benefits of demand response programs accrue from their ability to delay or eliminate the need for new generating capacity, transmission capacity or distribution investments. The success of energy efficiency programs in reducing overall energy consumption, combined with the availability of ample generation and transmission capacity, have reduced the economic benefit for demand response programs[8]. However, some owner communities have initiated rate-based demand response programs to reduce financial impacts from Platte River's wholesale rates, which employ both an "energy" and "demand" component.

For example, Fort Collins Utilities adopted time-of-day rates for all residential customers starting in 2018. This rate structure provides customers with an off-peak energy rate most hours and a higher on-peak energy rate four to five hours each weekday. The on-peak period brackets peak load hours that typically set Fort Collins' wholesale peak demand charges from Platte River. This rate is intended to promote conservation and load shifting from on-peak to off-peak times. In addition, Platte River and the owner communities have initiated a demand response pilot program in which Platte River can operate demand response assets controlled by Fort Collins Utilities and Longmont Power & Communications. Currently, this pilot provides approximately 3 MW of summer peak capacity savings, available for a few hours on peak demand days. This program enables Platte River to test communication and control system integration and to evaluate demand response program performance. The lessons learned from these performance evaluations will be used in future demand response program design. The existing voltage reduction program with the City of Longmont and thermostat program with the City of Fort Collins will be an important part of this and may be expanded in the future for managing loads during summertime peaks.

6.7.3 Distributed generation

Distributed generation programs are primarily run by the owner communities. Staff are modeling these programs due to their growing impact on net demand to be served by Platte River. Growth of distributed generation within the communities is driven primarily by the individual customers' adoption of (rooftop) solar generation to reduce their purchases of electricity. By the end of 2019, distributed solar within Platte River's owner communities totaled an estimated 19.7 MW (alternating-current basis), with 48% coming from residential net-metered solar, 9% commercial net-metered solar, and 43% owned or purchased directly by the owner communities. Figure 6-16 shows the growth of distributed solar capacity on Platte River's system.

[8] Demand response programs are not avoiding imminent investment in capacity expansion.

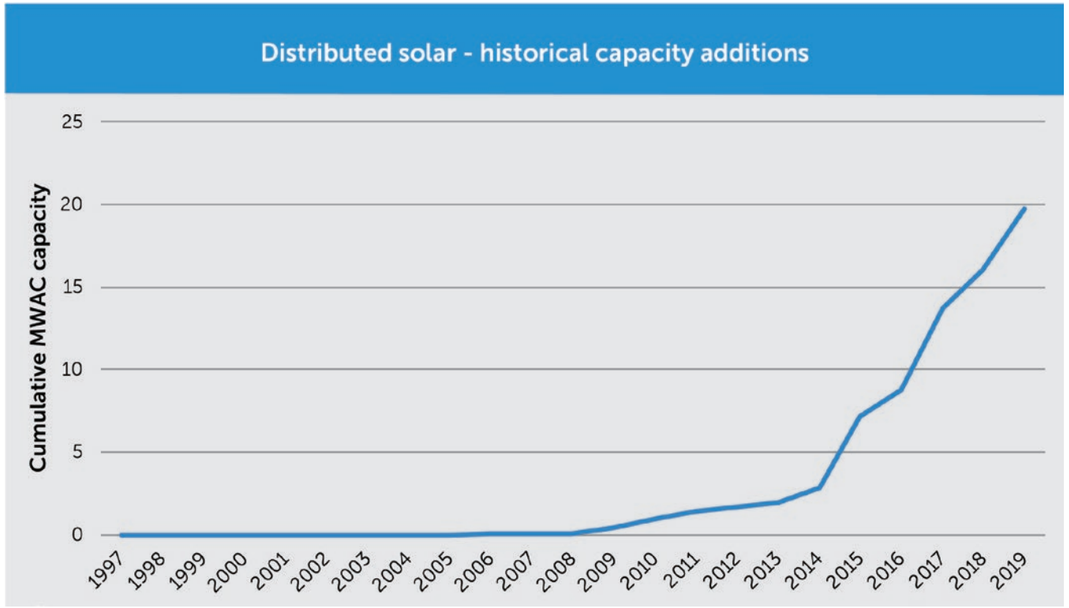


Figure 6-16

Distributed solar expansion stems from various incentives available and customer desire to reduce carbon emissions from electrical generation, notwithstanding its higher price. Responses to a recent request for proposal received by Platte River revealed that small scale distributed solar was more than twice the cost of utility-scale solar. While distributed solar capacity may continue to grow due to various incentives, customer preferences and specific locational advantages, its cost will likely continue to remain higher relative to the utility-scale solar due to economies of scale.

6.7.4 Beneficial electrification

Beneficial electrification refers to new uses for electricity that replace other sources of energy while also providing economic benefits, grid benefits and environmental benefits. As Platte River's owner communities pursue carbon emission reduction, beneficial electrification will become an attractive alternative. If load growth from beneficial electrification can be integrated flexibly and augmented with demand response capabilities, they may become a demand element complementary to (increased) supplies of intermittent renewable energy generation.

Electrification of the transportation sector, for example, is perhaps one of the most significant opportunities for beneficial electrification. EVs can help reduce overall emissions in communities where they replace conventional gasoline-powered vehicles. EVs can also provide flexibility to grid operations if properly integrated into the system, by leveraging intelligent charging to help add more renewables to the grid. Intelligent EVs may be connected to the real-time grid operation and programmed to prefer charging during hours with excess renewable energy availability. Platte River estimates EV energy consumption may exceed 70 GWh per year by 2030 and 300 GWh by 2040. To better understand charging patterns and future charging demand, Platte River has recently launched a smart charging pilot program for residential customers. Customers that enroll in this service are eligible to receive a $200 rebate on qualifying smart charging equipment. More than 100 EV customers have enrolled in this pilot and a program for managing these EV loads on the grid is currently under development.

6.7.5 Distributed energy storage

Distributed energy storage refers to batteries and other energy storage technologies connected to the distribution grid or at the customer's premises. As of the end of 2019, the communities had a total distributed storage capacity of 0.26 MW. Customers mostly use battery storage to reduce their peak demand and as a backup supply. Platte River is installing a 65 kWh battery at its headquarters building in Fort Collins. The purpose of this installation is to test control and operational optimization methodologies to reduce peak demand as a commercial customer. Battery control and operating strategies will become critical as technology improves, costs fall and the need to complement growing intermittent renewable generation rises.

6.7.6 Software for DER integration

Software architecture development will become critical for the integration of expanding DERs. Presently, Platte River is updating existing systems for this purpose but will eventually require a DER management system. This system will be designed, implemented and operated in close coordination with the owner communities to maximize the benefits of DER technologies. This architecture will enable power system operators to efficiently interface with multiple DERs when monitoring and balancing supply and demand on the grid. The initial goal for this system will be to provide a price signal or schedule to the various distributed resources connected with the owner communities' distribution networks. This system will allow customers to minimize their costs while simultaneously providing system operators capabilities and controls to reduce overall system costs while maintaining a high level of reliability.

6.8 Future DER programs

Platte River continues investigating the long-term potential of DERs along with collaborative implementation and integration strategies, engaging the services of HDR, Inc. to conduct a DER potential study for this IRP. In parallel, Platte River embarked on a DER strategic planning process, in collaboration with the owner communities (discussed in Section 6.9).

The DER potential study determined how DERs can support Platte River's development of a diversified resource mix. It estimated how much is achievable at a lower total cost relative to the cost of utility scale supply-side resources. The study also considered the rate at which distributed resources may be adopted over time and the utility incentives and administration costs required to achieve it. In addition, the study assessed how distributed resources will affect Platte River's hourly and annual loads.

The following sections provide an overview of the DER potential study process and results, as well as how the study results were incorporated into the IRP modeling. The study categorized results into three major areas: (1) energy efficiency, (2) demand response and (3) distributed generation. Long-term potential of these three categories is also discussed below.

6.8.1 Energy efficiency potential

HDR evaluated more than 50 common energy efficiency measures, ranging from more efficient lighting to advanced controls and retro commissioning, across multiple facility types, to estimate the technical, economic and achievable potential for energy efficiency (see appendix C for details). Technical potential is the energy and demand savings that would result if all energy efficiency measures were implemented without considering cost or other market barriers. Economic potential is the savings that would occur if all energy efficiency measures implemented have a cost that is less than the supply-side costs (including a carbon tax), were they implemented, regardless of market barriers. Finally, achievable potential is the portion of economic potential that can be achieved due to utility program interventions intended to help overcome market barriers. These interventions include marketing, education, energy advising and financial incentives or rebates.

HDR developed a detailed model to determine the cost-benefit analysis of various energy efficiency measures and their evolution over time. The results of this analysis estimated the achievable energy and demand savings for each hour of the year. In addition, it estimated costs to achieve the energy savings, comprising Platte River's costs for incentives and administration, as well as customer costs. The model also projects how these savings will grow over the years, with a portion of the energy efficiency savings assumed to be retired at end-of-life if the energy efficiency measures are not renewed.

Platte River used HDR's energy efficiency potential results to develop a forecast of energy efficiency potential and energy efficiency costs for the IRP model, starting from Platte River's existing energy efficiency program results and costs. This was important because it will take time to transition from existing program performance toward performance anticipated by the energy efficiency potential study.

All the energy efficiency measures were categorized into three portfolio options corresponding to three estimates of avoided supply-side costs:

- **Low energy efficiency potential:** The avoided cost assumptions for this case reflect how new resources are added only on an as needed or economical basis. The avoided capacity cost for energy efficiency was based on capacity cost of an aeroderivative gas turbine and avoided energy costs were based on forecasted market prices for electricity.
- **Medium energy efficiency potential:** Avoided costs for this case reflect anticipated costs of renewable resources. For this case, the avoided capacity cost for energy efficiency was based on batteries and avoided energy costs were based on a combination of delivered wind and solar energy costs.
- **High energy efficiency potential:** Avoided costs for this case were also chosen to reflect high-renewable portfolios, but with increased battery storage capacity.

The results indicate cumulative energy savings potential through 2030 of 340,000 MWh for the low energy efficiency case to 460,000 MWh for the high energy efficiency case. The cumulative investment ranges from $153 million to $253 million through 2030. Figures 6-17 and 6-18 show the growth in energy savings for the three energy efficiency cases and the annual utility cost for these programs.

For the low energy efficiency potential case, more energy efficiency becomes cost effective after 2030 as avoided supply-side costs rise. This drives greater energy efficiency potential and greater investment. For the medium energy efficiency potential and high energy efficiency potential cases, this potential is realized in early years, driving higher results and investments before 2030. However, after 2030, there is less cost-effective potential.

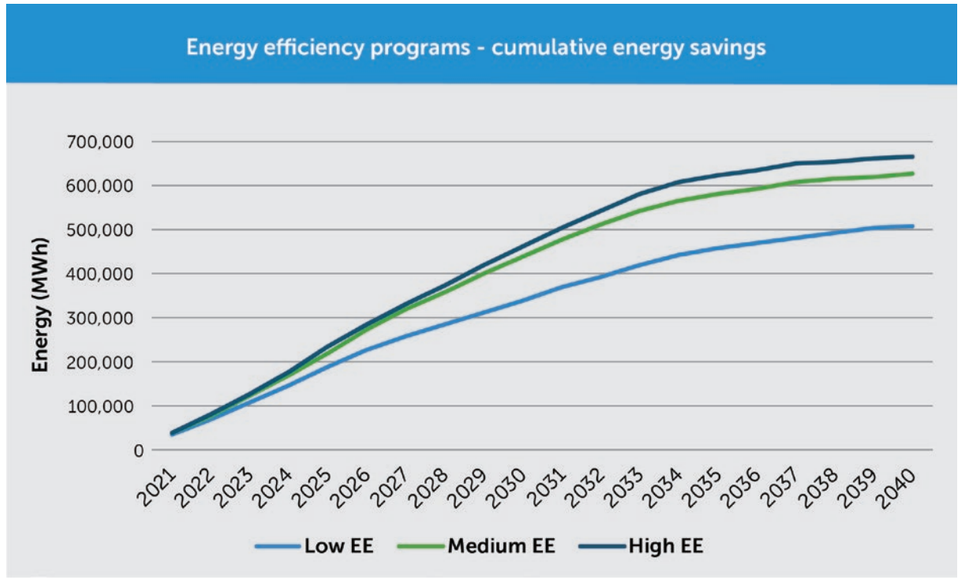


Figure 6-17

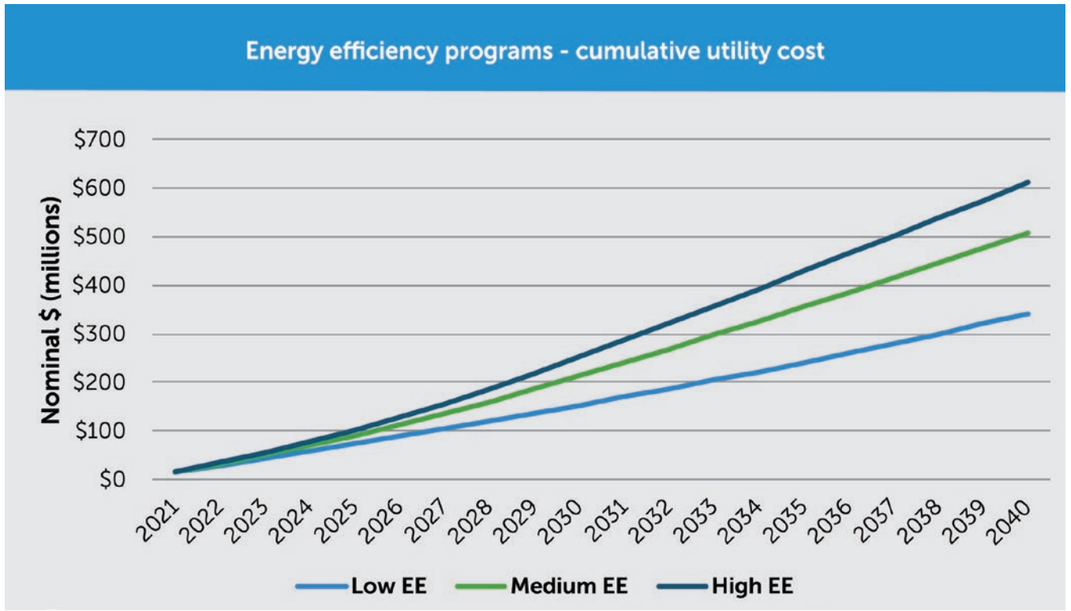


Figure 6-18

6.8.2 Demand response potential

HDR provided three levels of demand response potential based on the same avoided supply-side cost scenarios as described in the energy efficiency section. HDR evaluated traditional demand response technologies, including distribution voltage reduction and direct load control for common building loads like air conditioning and lighting. In addition, HDR evaluated EV charging and control of distributed batteries located in homes and businesses.

The figures 6-19 and 6-20 show the achievable demand response potential and utility cost for incentives and administration of demand response programs for the three cases. For the low demand response case, HDR found that distribution voltage reduction, direct-load-control of commercial and industrial air conditioners and interruption of select industrial processes provided achievable potential. These programs could achieve 5 MW of demand response potential by 2030 at a cumulative cost of just over $3 million. The medium demand response cases added control of residential heating, ventilation and air conditioning (HVAC) and electric water heaters as well as increased industrial process demand response potential. The result is a total of 19 MW by 2030 at a cumulative cost of $16 million. The high case includes increased penetration of HVAC control, resulting in a total of 38 MW at a cumulative cost of $34 million.

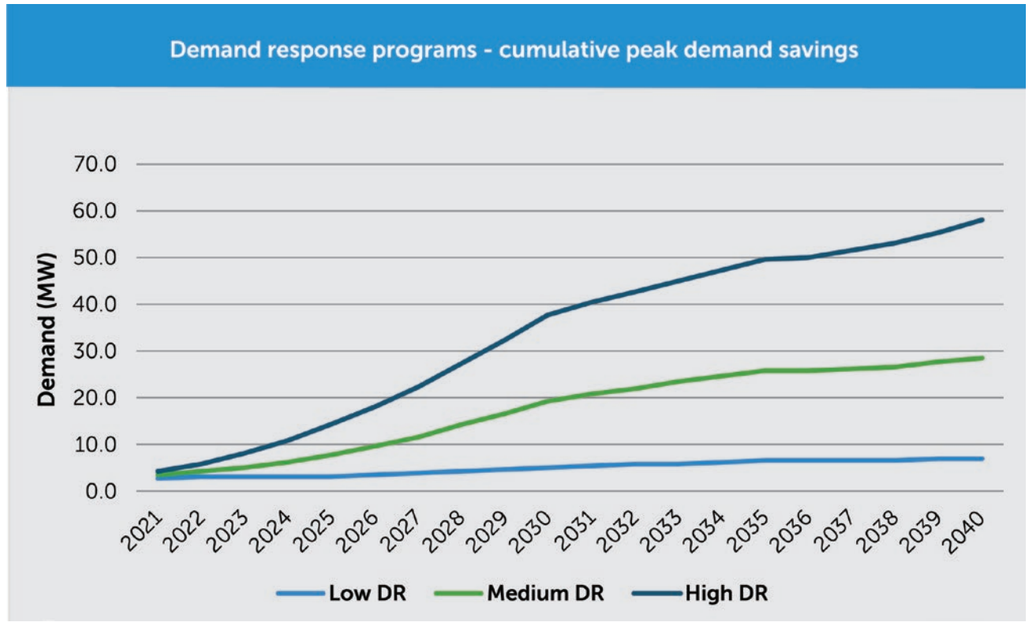


Figure 6-19

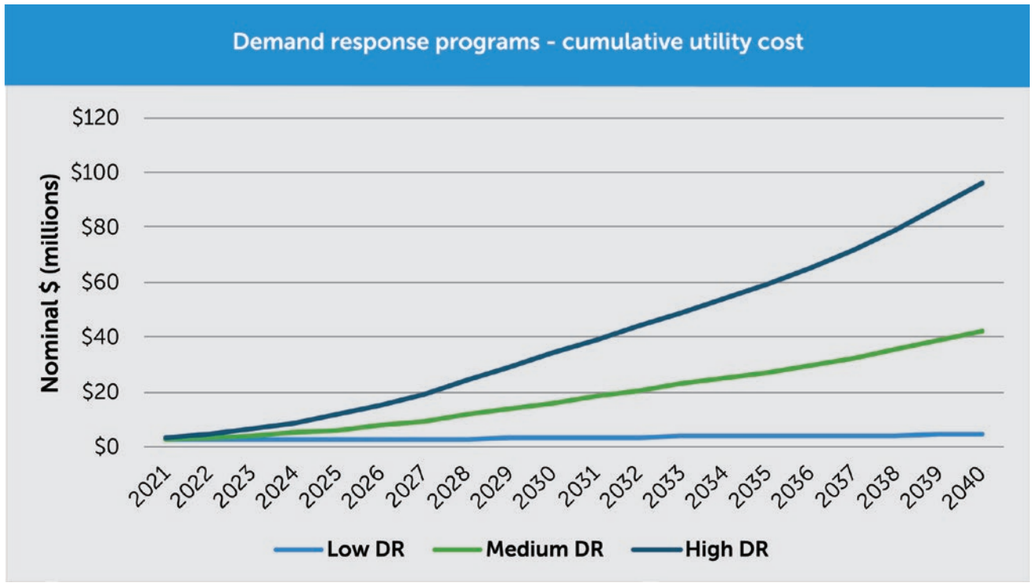


Figure 6-20

Note that some demand response technologies and program models were not evaluated as part of this demand response potential study. For example, it did not include an evaluation of retail time-of-use or real-time pricing rate structures. Such pricing structures may provide economic incentives to customers to shift use from high-cost to low-cost times. This may be facilitated by enabling technologies that can automate shifting of electric use for selected electric appliances or other equipment. However, effective use of these rate structures and technologies will require alignment and coordination of system operational needs as well as alignment and coordination of wholesale and retail rate structures. This work is part of the DER strategic planning process described in Section 6.9.

6.9 DER strategy

Continued growth in DERs will require a more coordinated approach between Platte River and its owner communities to expand and integrate them in a reliable and financially sustainable manner. Platte River and its owner communities recently initiated a DER strategic planning process. While Platte River has made significant investments in energy efficiency programs, other forms of distributed resources, such as demand response, distributed generation, distributed energy storage and beneficial electrification are expected to grow in prominence. These forms of DERs have the potential to provide significant benefits to Platte River's customers and the electric system but only when challenges are met concerning:

- Ability to determine and evaluate in a coordinated fashion wholesale utility, retail utility and customer benefits and costs associated with DERs;
- Development of wholesale and retail rate structures that appropriately reflect and allocate the costs and benefits of DER investments;
- Development of policies and standards to maximize DER reliability, flexibility and predictability; and
- Ability to meet customers' interests and expectations for DERs.

Through the DER strategic planning process, Platte River and its owner communities intend to address these issues and collaborate to develop a common vision, objectives and initiatives. In addition, the team will collaborate with stakeholders and the public to develop a common framework for evaluating DER initiatives and business models.

The DER strategic planning process will continue through mid- to late-2021 and will have significant bearing on the potential that Platte River and its owner communities can achieve in a reliable and financially sustainable manner. Therefore, the results from the DER potential study discussed earlier should be considered a draft, with conclusion to follow completion of the DER strategic plan. Once the strategic plan is completed, Platte River and its owner communities will determine whether a new forecast of long-term DER potential is warranted within the next IRP cycle.

7 IRP supply-side assumptions

This chapter reviews supply-side resource assumptions available to serve projected demand. These assumptions include commodity fuel prices, resource costs and their future trajectory, as well assumptions about how Platte River interacts with other power suppliers in the immediate region. The study period spans 20 years starting Jan. 1, 2021, largely because the typical life of investments for new generating capacity is 20-30 years.

7.1 Inflation and discount rate

Staff used a 2% inflation and general escalation factor when estimating costs for potential new generating capacity. Fixed operation and maintenance costs for power generation facilities were escalated at 3.5%, which aligns with cost increases incurred for Platte River's current thermal generation fleet. In the future, two drivers will place fixed operating costs higher than the rate of inflation: shifting operational paradigms and resulting maintenance. Assets are aging and their usage will shift from baseload or peaking roles to a balancing role in which they follow intermittent, renewable generation. In addition, an escalation rate of 3% was used for the social cost of carbon.

Along with escalators noted above, staff used a discount rate of 5% for net present value calculations, which are in line with Platte River's long-term cost of capital. Present values are presented in 2020 dollars.

7.2 Regional import/export limits

Platte River transacts with three neighboring utilities – Black Hills Energy, Colorado Springs Utilities and Xcel Energy – through the JDA and on a bilateral basis. Outside of the JDA, Platte River may work with other utilities to buy and sell energy on a bilateral basis.

For IRP modeling, analysts assumed purchases or sales up to 200 MW in any hour, which is approximately 50% of Platte River's anticipated 2030 average hourly demand. The 200 MW transaction limit ensures market transaction volume remains realistic. For modeling purposes, total annual volume of imported energy was limited to not only mitigate risks associated with the market purchase of large quantities of low-cost power but also to better calculate carbon emissions (or lack thereof) from generating resources. To balance the opportunity to purchase low-cost energy without becoming overly reliant on outside generators, market purchases were unrestricted for the first five years when Platte River would have more price forecast certainty and then gradually reduced to only 5% of its annual energy needs in 2030 and later. No limit was placed on energy exports to maximize benefits to the owner communities through economic sales from Platte River's generation assets.

7.3 JDA modeling

As mentioned in Section 3.4, the JDA acts like a small-scale hourly energy imbalance market. As a participant in the JDA, Platte River can buy and sell power from its utility partners within the hour, following re-dispatches. These real-time transactions are separate from the bilateral market described in Section 7.2 and are modeled in Aurora as a unique resource. The quantity and pricing of JDA energy depends on the real-time imbalance of economic energy among the local participants, so it is difficult to forecast from a fundamental model in the same manner as the price forecast prepared by Siemens. Instead, pricing and volumes were forecasted based on historical data. Hourly historical data for both prices and volumes were reviewed with an emphasis on the most recent data. For each month, a typical week was developed that gave the model a maximum volume of energy and the expected price for every hour of the week. Based on those inputs the model can choose to buy energy to replace native generation. Since JDA energy re-dispatches units (replaces more expensive generation with lower cost energy), constraints are set to ensure JDA purchases only offset existing generation and cannot be used as additional energy. JDA sales were modeled in a similar manner. The only restriction on sales was the total hourly volume, which was designed to ensure future JDA sales volumes roughly align with historical results.

7.4 Commodity price projections

Commodity price projections are a key input to resource planning. Platte River engaged Siemens Energy Business Advisory (previously Pace Advisory or Siemens) to provide regional natural gas, power and CO_2 cost projections. Coal prices were projected by Platte River based on unique coal supply plans for its coal fired generation fleet. Following subsections discuss these commodity price projections in more detail.

7.4.1 Natural gas prices

Siemens provided a monthly natural gas price forecast for the Colorado Interstate Gas (CIG) trading hub, extending through the planning horizon. In addition, Siemens also supplied a low gas price and a high gas price forecast to show a band of uncertainty around the base forecast. The high- and low-price projections reflect changes to the underlying fundamentals of the gas market such as production volumes, export volumes or changes in consumption. All three gas price projections are shown in Figure 7-1.

In addition to the above gas commodity prices, Platte River also pays a transportation charge to pipeline owners for natural gas delivered across their pipelines. This was priced at the actual value of $0.87/MBtu for 2020, rising at the rate of inflation.

For new gas fired power plants, two additional gas-related cost components were also included in the analysis. The first covers the construction of an additional pipeline spur needed to serve new generating resources and the second covers the cost of firm gas capacity reservation on interstate pipelines to ensure delivery during critical times. Those costs are discussed further in the supply-side resources section.

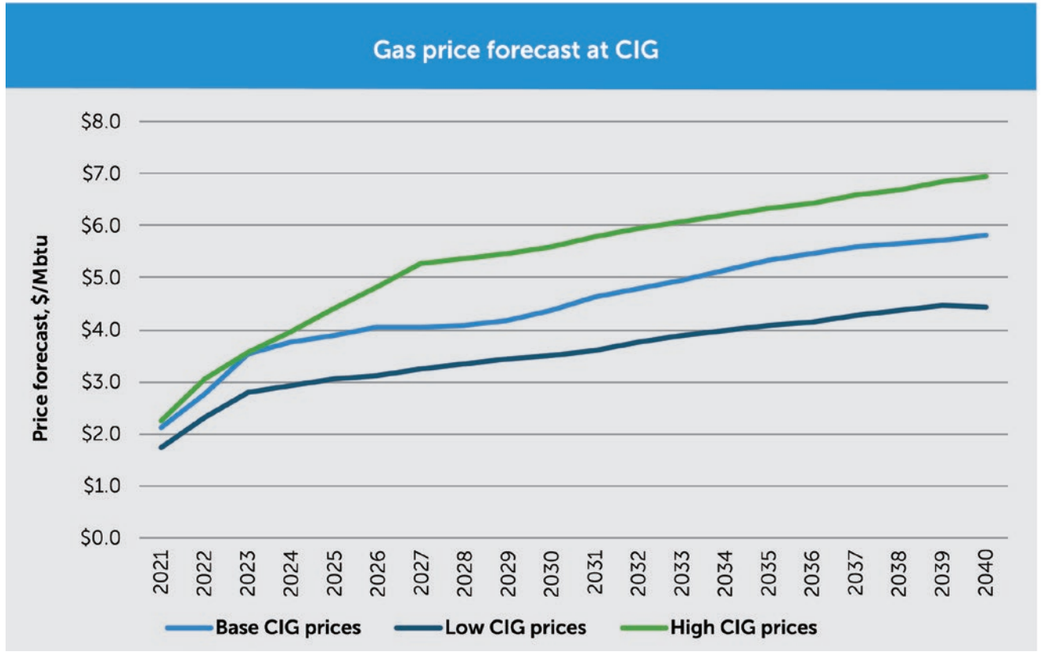


Figure 7-1

7.4.2 Regional power prices

Regional power prices impact the four portfolios discussed in this IRP because they allow for the purchase and sale of energy on an economic basis. During portfolio simulations, the Platte River system was allowed to buy power when the regional market price is lower than Platte River's marginal cost to produce electricity and allowed Platte River to sell excess power when the market prices are higher than its marginal cost. Margins from these transactions reduce the overall cost to Platte River's owner communities.

As Platte River's system and the regional electric grid evolve to integrate larger amounts of renewables, the linkage between power prices and renewable energy generation becomes more important. With more renewable resources on the regional grid, renewable energy becomes an even bigger driver of power prices. Siemens predicts that sunny on-peak hours, currently the highest-cost hours, will eventually become lowest-cost hours as solar energy saturates the region. This trend is clearly visible in Figure 7-2 which shows power price forecast in the Platte River area.

In the past, price forecasts were provided as monthly on-peak/off-peak values which were then used to produce an hourly price shape. For the 2020 IRP, Siemens provided an hourly price forecast and the renewable energy patterns used in their price forecasting models, which helped ensure consistent relationships between the price of intermittent wind and solar energy production levels. Because Siemens supplied the natural gas and emission prices forecasts, the ecosystem of assumptions was appropriately correlated down to an hourly level to ensure internal consistency among various projections.

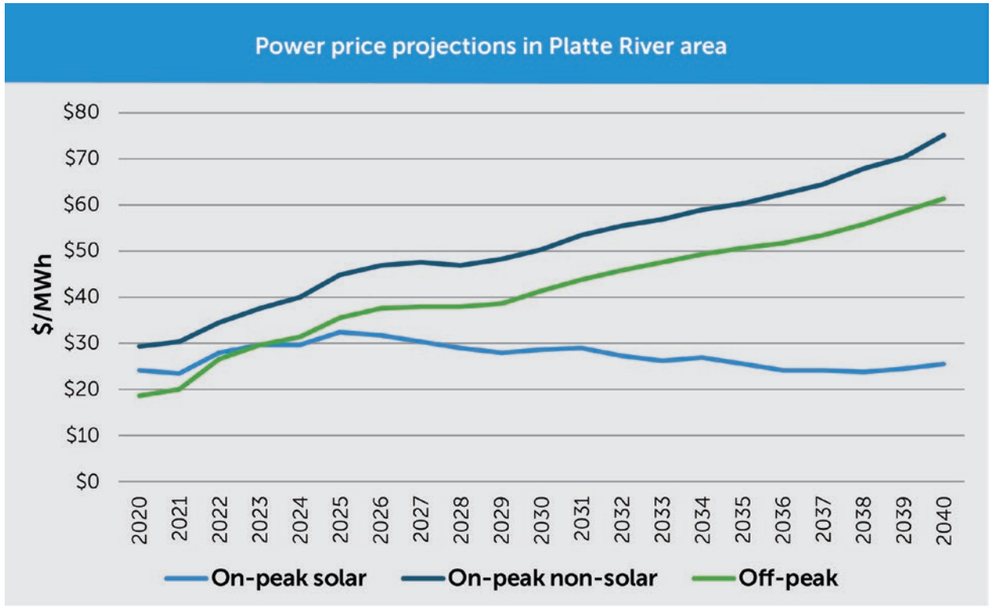


Figure 7-2

7.4.3 Coal prices

Each coal plant in Platte River's portfolio operates with a unique coal supply arrangement, so price forecasts for the two Craig coal units and Rawhide Unit 1 were developed separately. Rawhide receives coal from the Powder River Basin and its price forecast is largely based on broader market prices. Near-term prices reflect existing contracts and prices that have been locked in with the supplier(s) and near-term coal market assessments and indices. As locked-in quantities and/or the quantities with prices tied to market indices decrease over time, the remaining coal is priced at Siemens's forecast for Powder River Basin coal. By 2024 the price forecast is based entirely on the forecasted commodity price from Siemens. The commodity price is adjusted to reflect mine-specific pricing and additional costs Platte River pays for required dust suppressants. Transportation expenses, based on the current projections, are also added to forecast delivered coal price.

The overall Craig coal price forecast is based on price forecasts provided by the Trapper Mine, which is adjacent to the Craig plant. Platte River has a partial ownership interest in Trapper Mine and coal costs are determined on a "cash cost" basis, with no transportation costs incurred. Figure 7-3 illustrates the delivered coal prices for Platte River coal plants.

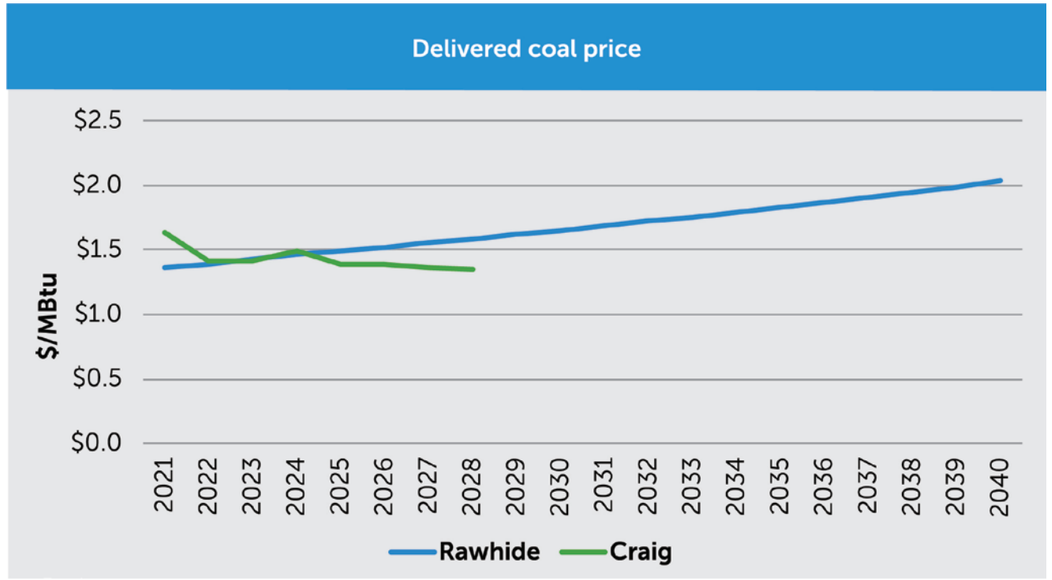


Figure 7-3

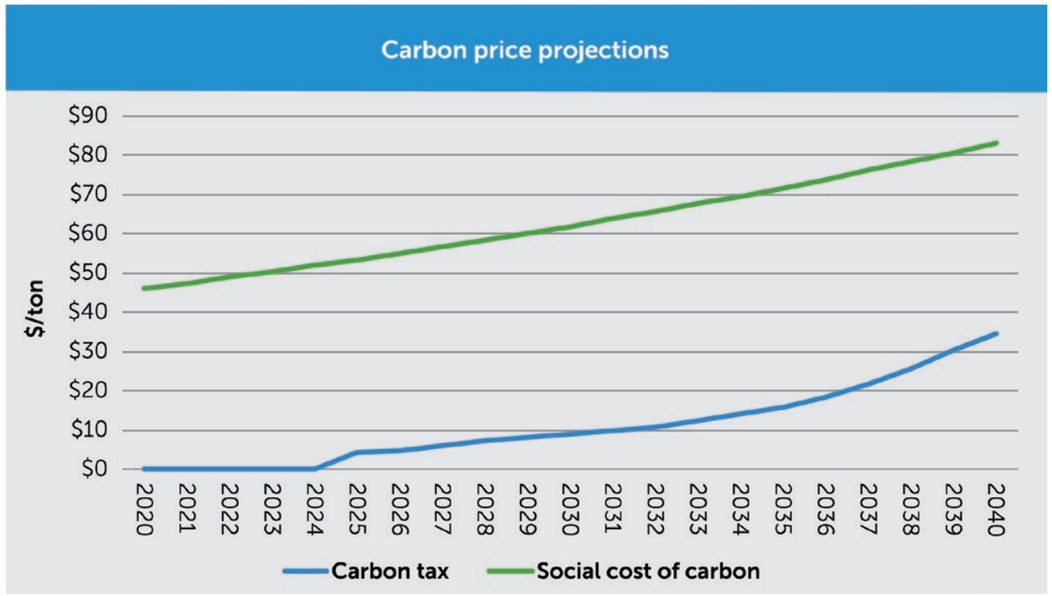


Figure 7-4

7.4.4 Carbon prices

Siemens supplied a carbon price (tax) forecast based on its expectations concerning public policy discussions and potential legislation, as shown in Figure 7-4. Platte River also evaluated portfolio outcomes using the social cost of carbon in the sensitivity studies. Unlike a carbon tax, which disincentivizes carbon emissions, a social cost simulates total direct and indirect costs to the society that would otherwise be externalized and quantifies potential inter-generational cost shifts. The specific costs used were based on language in Colorado Senate Bill 19-236, which references the 2016 report produced by the Interagency Working Group in Social Cost of Greenhouse Gases.

7.5 Supply-side generation resources

This section contains a discussion of all power generation resources considered by Platte River to meet its owner communities' future electricity needs beginning with a discussion of the resource screening process and a listing of the resources that were screened out and not considered in the IRP as candidates for investment. A detailed discussion follows concerning the resources (both renewable and traditional) that were considered for investment in the IRP. Finally, the section features a list of Platte River's existing resources including physical generation assets and contracted third party resources.

7.5.1 New resource screening

Platte River considered a large number of generating resources for this IRP. Some of the resources were screened out due to size, technology commercialization status and suitability for Platte River's system. These resources are listed here along with the rationale for their unsuitability. Platte River will continue to monitor the commercial viability of these resources as technology evolves and suitability for Platte River improves.

- **Conventional nuclear** – large reactor sizes, high costs, long construction durations and permitting challenges
- **Small modular nuclear reactors** – no commercially proven examples
- **Coal integrated gasification and combined cycle with carbon capture and storage** – high cost, immature technology
- **Pumped storage hydro** – limited regional resource availability, high cost, long permit and building timeline
- **Compressed air energy storage** – limited regional resource availability
- **Flow batteries** – few commercially viable options, high costs and lower efficiency compared to lithium-ion batteries
- **Geothermal** – limited regional resource availability
- **Biomass** – limited production potential, high costs
- **Municipal waste** – limited production potential, high costs
- **Solar thermal** – limited commercial penetration, high costs

The following is a list of technologies that were considered for inclusion in the IRP:

- **Wind turbines** – favorable resource availability, technological improvements, stable or declining costs
- **Solar photovoltaic** – favorable resource availability, technological improvements, stable or declining costs
- **Lithium-ion batteries** – peaking capacity and renewable energy integration, technological improvements and declining costs
- **Small thermal generation** –
  - **Combustion turbines Aero derivatives and 7F** – mature technology, suitable for load following and integration with intermittent renewables
  - **Combined cycles, 1X1 Aero derivative and 7F** – mature technology, suitable for load following and integration with intermittent renewables
  - **Reciprocating internal combustion engines (RICE)** – mature technology, emerging resource for load following and integration with intermittent renewables in small scalable sizes

Techno-economic data for the above four types of resources considered for inclusion was received from outside consultants such as Siemens and HDR Inc. New resources were used in different block sizes based on their design and suitability for Platte River's system. Wind and solar were added in 100 MW blocks of nameplate capacity while storage battery resources were added in 50 MW X 4-hour (200 MWh) blocks. Thermal resources were added at the standard sizes available in the market.

7.5.2 New wind resources

For the purpose of IRP modeling, 100 MW blocks of nameplate wind capacity were added through PPAs using a 30-year levelized annual payment instead of one-time capital expenditure. PPA payments compensate the developer or PPA counter party for capital costs (depreciation and returns), interest during construction, taxes (sales, property and income) and ongoing O&M costs.

Wind power plants were modeled with a 45% capacity factor; costs used in the model are shown in Figure 7-5. These are nominal values that increase at a lower rate than inflation due to technology maturation. The relatively sharp price increase in 2022 stems from the reduced production tax credit. Platte River received wind price data from Siemens and calibrated it to match recent market transactions in the area.

In addition to the wind PPA cost, Platte River also pays its transmission provider a fixed monthly cost for services associated with integrating variable resources, such as wind and solar. These charges are set by the Federal Energy Regulatory Commission and are known as "Schedule 3" and "Schedule 16" charges. These charges have remained steady over the last few years, therefore no escalation was assumed. The Schedule 3 charge is $0.16/kW/month and Schedule 16 charge is $0.91/kW/month applied to all nameplate capacity amount of wind.

Wind resource availability within Platte River's service territory is limited and future new wind resources will ultimately require new transmission capacity to be built or procured. Consequently, staff assumed any new wind capacity above the next incremental 100 MW block will require new transmission capacity. For planning purposes, an additional transmission wheeling cost equal to the average of WAPA and Xcel Energy transmission tariffs was used. Figure 7-5 shows wind costs, including estimated generator transmission interconnection costs, with and without third-party transmission wheeling costs. Figure 7-5 shows fixed payments for the duration of the PPA for the particular start year. For example, a wind project that begins commercial operation in 2021 is estimated to cost fixed $20/MWh over the 30-year PPA term and a project starting commercial operation in 2024 will have a fixed cost of $23.42/MWh for the duration of the PPA.

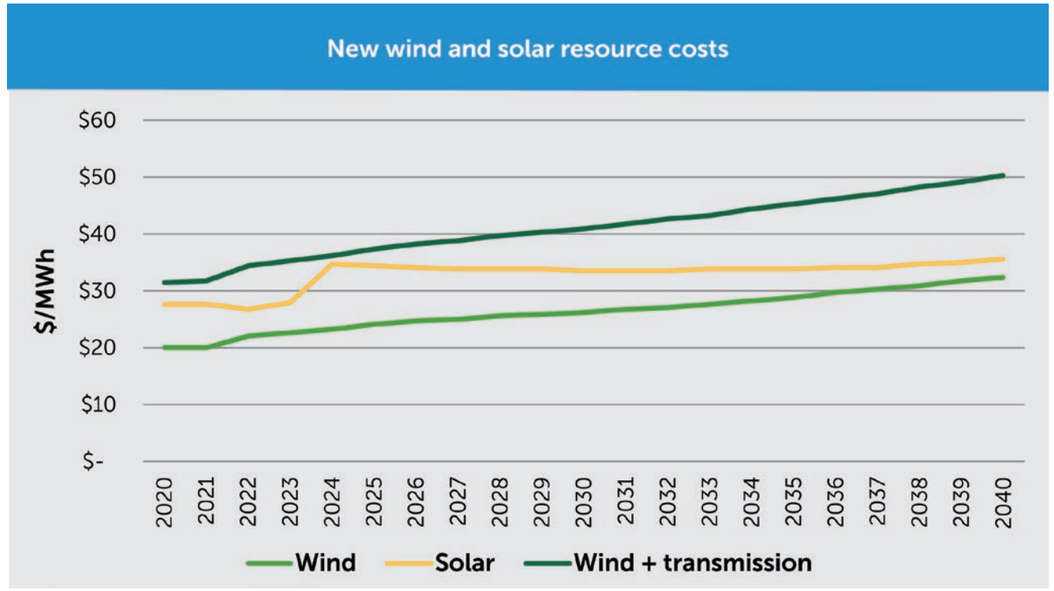


Figure 7-5

7.5.3 New solar resources

Like wind, new solar resources were considered as 100 MW block sizes priced at 30-year levelized PPA payments including transmission interconnection costs. Solar generation is assumed to have an annual capacity factor of 28%. Annual prices for solar resources were developed by Siemens and calibrated to reflect recent transactions in the area.

Staff assumed that new solar projects will be built within the existing Platte River transmission footprint. Consequently, no new transmission capital costs or third-party wheeling costs were assumed for solar generation. Figure 7-5 illustrates the cost of solar generation, declining slightly in nominal terms, indicating technology improvements over time. The sharp price increase in 2024 stems from the Investment Tax Credit reduction from 30% to 10%. Figure 7-5 shows fixed payments for the duration of the PPA from the particular start year. For example, a solar project that begins commercial operation in 2023 is estimated to cost a flat $28/MWh over the 30-year PPA term while a project starting in 2024 will have a cost of $35/ton for the duration of the PPA.

7.5.4 New battery storage

Platte River considered commercially available lithium-ion battery storage technology in 50 MW block sizes. Staff assumed 200 MWh of storage per battery, which would provide up to four hours of discharge capacity at a rate of 50 MW per hour. Other combinations of storage and capacity sizes can be built as well. For example, an equivalent 2-hour battery would still store 200 MWh but could charge or discharge at 100 MW per hour. An 8-hour battery that stores 200 MWh could only charge or discharge at 25 MW per hour. Each type of configuration has appropriate uses. A 2-hour battery provides superior flexibility but at an added cost of more inverters relative to the number of battery cells. In contrast, 8-hour batteries offer cost savings on non-battery equipment such as inverters, but their flexibility can become constraining as energy cannot flow into or out of the battery as quickly. For modeling, the 4-hour battery provides a balance of cost and flexibility. As with other candidate resources, once Platte River decides to install new battery storage resources, the full range of available options will be considered to ensure each project uses the best available option for the specific needs of the system at that time and location.

The batteries were assumed to have an 85% round trip storage efficiency. Like wind and solar, battery storage cost was modeled as a PPA-type payment to a developer or counter party for a 15-year term with all future battery storage projects sited within Platte River territory, thereby avoiding third-party transmission wheeling costs. Figure 7-6 shows the levelized battery costs for a 50 MW 4-hour battery over the 15-year term of the PPA. For example, a 15-year 50 MW 4-hour battery that begins commercial operation in 2023 is estimated to cost $10/kW-month over the entire 15-year term.

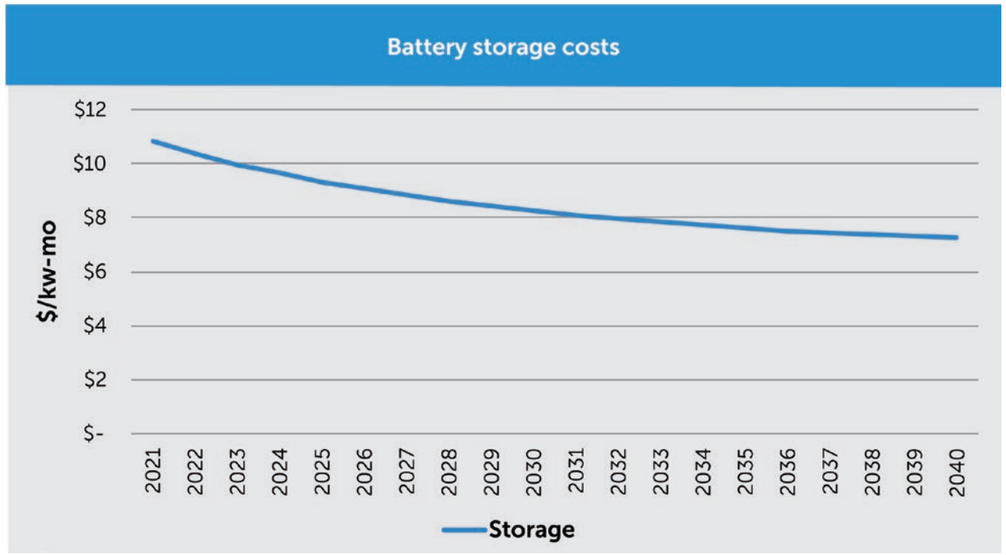


Figure 7-6

7.5.5 New thermal generation resources

Platte River screened a range of thermal generating options before advancing a limited portfolio of resources to the expansion planning model. Emphasizing decarbonization and integrating more renewable resources, the modeling focused on smaller, more flexible thermal generation resources, including aeroderivative combustion turbines, combined cycles and reciprocating internal combustion engines (RICE). Screening performed by HDR Inc. indicated that RICE units are competitive with other technologies and a good complement to intermittent renewable generation. The Aurora model developed new generation expansion plans, often selecting RICE as a least-cost solution. RICE units also offer significant operational advantages with their ability to run at low levels, start and stop frequently with little added cost impact and the potential option to operate on a variety of fuels such as natural gas or biodiesel. Their small size, modularity and scalability also makes them convenient to site and construct.

New thermal generation costs and operational details provided by HDR Inc. and used in Aurora are shown in Figure 7-7.

Since HDR supplied only a single year snapshot of costs, Platte River used Siemens' technology cost escalation methodology to adjust for future year prices. This adjustment is separate from the standard 2% inflation modification. It reflects cost trends for both mature and newer technologies.

Staff assumed any future thermal generation will be sited at the Rawhide Energy Station and would require the construction of an additional gas pipeline spur at a cost of $6.0 million. To ensure reliability, Platte River would also need to purchase firm gas transport capacity on the gas delivery system. Actual gas supply cost will vary depending on the consumption level, but the added cost averages $1.65/kW/month across all thermal resources.

New thermal generation resource data							
Unit	Maximum capacity (MW)	Minimum capacity (MW)	Installation cost ($/kW)	Fixed O&M ($/kW-mo)	Variable O&M ($/MWh)	Efficiency	CO_2 emission rate (lbs./MWh)
Rice6x0	111	9	$1,252	$0.50	$5.42	41%	987
Rice3x0	55	9	$1,389	$0.91	$5.42	41%	987
Aero CT	83	21	$1,184	$0.78	$6.10	36%	1110
2x1 Aero CC	108	29	$1,748	$2.45	$4.81	47%	850
7FA Frame CT	194	98	$715	$0.39	$4.29	35%	1144
7FA 1x1 Frame CC	275	147	$1,322	$1.03	$4.74	50%	801

Figure 7-7

7.5.6 Platte River's existing resources

Platte River's existing supply-side resources consist of power plants, PPAs and community solar generation facilities. Distributed solar or community-owned solar were modeled as supply-side resources even though they may have unique contracts with retail load or on Platte River's member distribution utility. For modeling purposes, they act as resources that serve community load.

Platte River entered into some capacity and energy sale transactions to optimize its supply portfolio. These contracts were modeled in Aurora to ensure the generation necessary to supply the contracted sales is appropriately accounted for when making dispatch and resource optimization decisions. Figure 7-8 summarizes the committed transaction as of Jan. 1, 2020. Figure 7-9 shows all the existing generation resources.

Committed power transactions data					
Sale transactions	Nameplate capacity (MW)	Effective capacity (MW)	Type	Commercial operation	Normal retirement / contract expiration
25 MW sale from Craig	25	25	Baseload	2019	2024
25 MW sale from Craig	25	25	Baseload	2020	2022
Silver Sage	12	3	Wind	2018	2042
Spring Canyon II	32	7	Wind	2020	2030
Spring Canyon III	28	6	Wind	2020	2030

Figure 7-8

Existing generating resource data				
Thermal generation facilities	Nameplate capacity (MW)	Effective capacity (MW)	Commercial operation	Nominal retirement / contract expiration
Coal				
Rawhide Unit 1	280	280	1984	2046*
Craig Unit 1	77	77	1980	2025
Craig Unit 2	74	74	1979	2028**
Natural gas (simple-cycle CTs)				
Rawhide Unit A	65	65	2002	Indefinite
Rawhide Unit B	65	65	2002	Indefinite
Rawhide Unit C	65	65	2002	Indefinite
Rawhide Unit D	65	65	2004	Indefinite
Rawhide Unit F	128	128	2008	Indefinite
Other resources				
Wind				
Medicine Bow	6	1	1998	2033
Silver Sage	12	3	2009	2029
Spring Canyon II	32	7	2014	2039
Spring Canyon III	28	6	2014	2039
Roundhouse	225	50	2020	2042
Hydropower				
Loveland Area Project	30	30	1973	2054
Colorado River Storage Project	60	60	1973	2057
Solar				
Commercial solar power purchase program	4	2	Approved 2013	Varies
Fort Collins community solar	1	0.4	2015	2040
Foothills Solar (Platte River share)	0.5	0.2	2016	Indefinite
Rawhide Flats	30	13	2016	2040
Rawhide Prairie	22	6	2020	2040
New solar* **	100	26	2023	2040
Storage				
Rawhide Prairie Battery	1 MW x 2 hours	1	2020	2040

Figure 7-9

* This was the original retirement data for Rawhide Unit 1 at the time of modeling during fall 2019. With the announced retirement of Rawhide Unit 1 in 2030, this assumption has been superseded.

**We assumed a December 2028 retirement date for modeling purposes. Later on, a retirement date of September 2028 was announced which would not change the results of this IRP.

***Platte River is currently conducting a solicitation for 50-150 MW of solar to come online by December 2023. For modeling purposes, a 100 MW capacity addition was assumed, but later on a 150 MW project was approved.

8 Reliability planning and future portfolios

This chapter includes a discussion of two key IRP topics: planning for reliability with intermittent resources and the development of four portfolios to cover a wider range of future possibilities. These topics are discussed with the backdrop of Platte River's Resource Diversification Policy and the organization's foundational pillars of safely providing reliable, environmentally responsible and financially sustainable energy and services to its owner communities.

8.1 System reliability

Near- and long-term resource planning is the first step in ensuring reliability. Failure to plan for adequate energy supply may cause supply shortages, which, if sustained, can cause significant economic damage. For example, Electric Reliability Council of Texas (ERCOT) customers recently paid 300 times the average price of $30/MWh for energy (about $9,000/MWh) for a few hours due to supply shortages[9]. Fortunately, this episode lasted only for a few hours in the ERCOT market. If the demand was to go any higher, or if any generating unit was to breakdown during these super peak hours, ERCOT would have to resort to supply curtailment (or load shedding). In addition to the economic impacts, curtailments due to a lack of adequate supply will likely impact public health and safety.

To maintain sufficient resources to meet demand, referred to as resource adequacy, staff must account for electric demand that changes hourly and by season. Peak demand for electricity on the Platte River system during a hot summer day can be more than twice the demand during a spring or fall day. Platte River must always build or procure enough supply resources to meet this peak demand. Figure 8-1 shows Platte River's average hourly demand during a summer, spring, fall and winter day in 2018.

[9] https://www.reuters.com/article/us-texas-power-demand/texas-power-prices-nearly-triple-to-record-high-as-heat-bakes-state-idUSKCN1V61CG

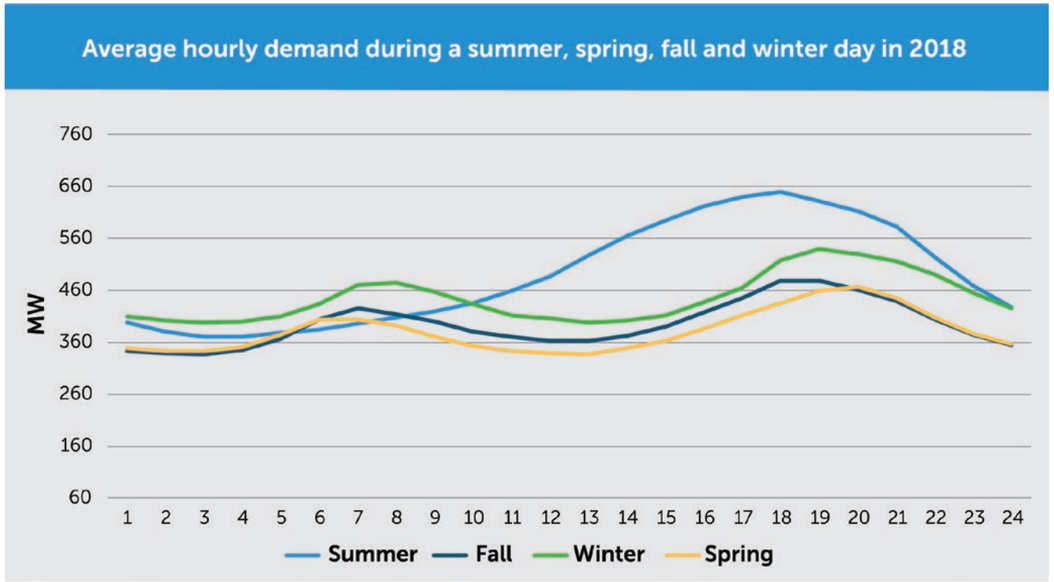


Figure 8-1

8.1.1 Reliability modeling with planning reserve margin

An electric utility ensures long-term resource adequacy by meeting the North American Electric Reliability Corporation (NERC) criterion of allowing just a single day outage within a 10-year period or 2.4 hours of outage per year. To meet this criterion, NERC recommends using a 15% PRM, which is additional capacity above peak demand expectation. If a utility is expecting a peak demand of 100 MW in a future year, for example, it should build or acquire 115 MW of generating capacity. This level of PRM is necessary to account for (1) forecast errors, (2) unplanned outages of generation resources and (3) transmission outages.

While a 15% PRM works well with dispatchable thermal resources, the inclusion of intermittent non-dispatchable renewable resources in the supply mix means additional considerations must be given to the probability of renewable resources being unavailable during peak demand periods. Due to the complexity of estimating the reliability contribution of renewable resources, Platte River hired an independent consultant, Burns and McDonnell, to recommend reserve margin guidelines. Their report describes different techniques they used to evaluate reliability, ultimately concluding a 15% PRM is still appropriate for Platte River as long as proper adjustments are made to the peak hour capacity contribution from renewable resources and battery storage as described below. The full report can be found on the Platte River website.

8.1.2 Reliability contribution of renewable and storage resources

Intermittent renewable resources such as wind and solar contribute to reliability in a probabilistic way so additional analysis is required to estimate their contribution to meeting the annual peak demand, known as effective load carry capability (ELCC). In general, ELCC of an intermittent resource is the equivalent MW contribution of a firm resource in meeting the peak demand. Figure 8-2 explains the concept of ELCC for Platte River's system for an illustrative day. Hourly load profile for the day is shown as a green line in the chart. The peak demand for the day is 700 MW. Installed capacity of wind is 228 MW and the installed capacity of solar is 50 MW in this example. Hourly load profile after reducing the load for available wind and solar is shown in blue color. The net peak demand after considering the available wind and solar that day is 627 MW.

Based on this data, the ELCC of 278 MW of wind and solar is (700-627)/278 = 26.3%.

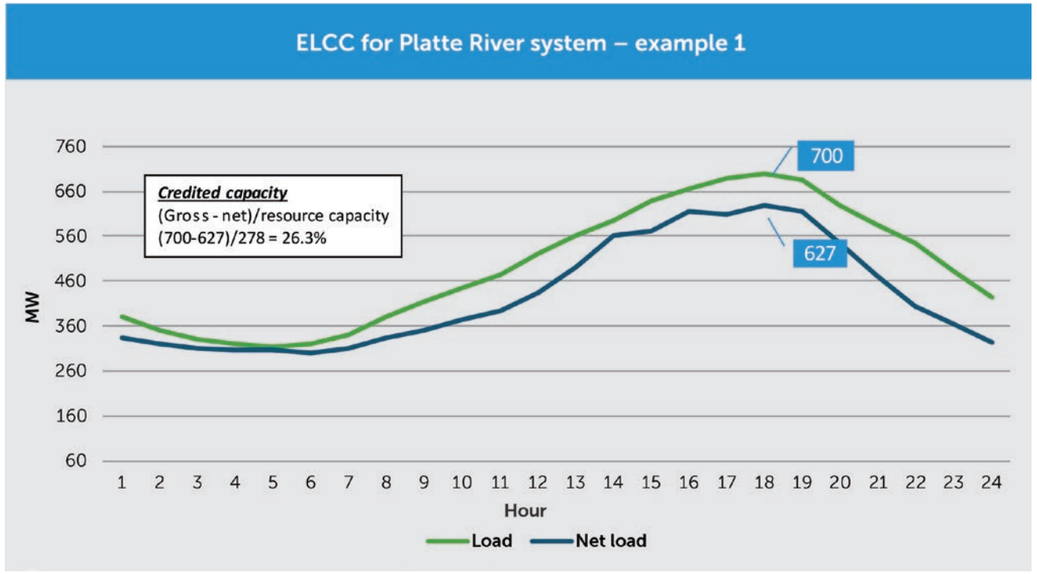


Figure 8-2

Now consider another wind and solar profile shown in Figure 8-3. In this case wind generation starts increasing around 4 p.m. and reduces the net demand to less than 600 MW at 6 p.m. The wind then starts slowing down and the contribution from solar also decreases. Net load at 7PM is 639 MW. This is the new net peak load and the peak hour has shifted from 6 p.m. to 7 p.m. In this case, the peak impact of wind and solar is 673 less 639, that is only 34 MW. The ELCC of wind and solar in this case is (673-639)/228 = 12.2% as show in Figure 8-3.

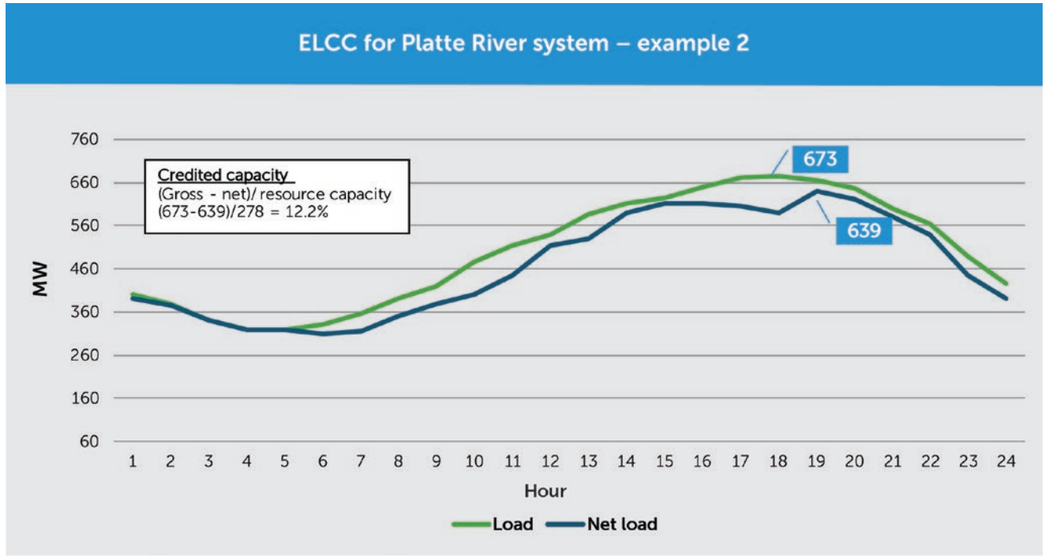


Figure 8-3

Renewable energy output tends to be geographically correlated (typically, it is windy or sunny across the region). The ELCC of additional renewable resources generally drops as more resources are added to the grid. For example, if the ELCC of the first 100 MW of a wind (or solar) project is 30 MW, the ELCC of a second 100 MW block of the same resource type in the geographic vicinity will be less than 30 MW.

Similarly, battery storage also contributes to reliability in a probabilistic manner because it is an energy-limited resource. Battery storage may be dispatched to meet load, but only for a limited duration and only if it is charged before the dispatch. As with wind and solar, the reliability contribution of incremental battery storage also drops as more and more storage is added to the system because of the lower probability of being fully charged at the time of peak.

Platte River's consultant Burns and McDonnell recommended declining values of ELCC with incremental resource additions for wind, solar and battery as shown in Figure 8-4. The figure 8-4 shows the average ELCC contribution from the existing wind is 22% and the existing solar is 42%.

For the next block of 100 MW of wind, the ELCC contribution drops to 14%, while the solar ELCC drops to 26%. The ELCC contributions from the next blocks of solar and wind are even lower. ELCC of the first block of 100 MW of battery is 77%, while the ELCC of the next 100 MW block drops to 54%. This declining pattern continues just like wind and solar.

The PRM reliability construct was developed for North America's generation system which is dominated by dispatchable thermal resources. With majority thermal resources providing firm capacity and some hydroelectric storage resources, a value of 15% PRM has been providing adequate reliability for North American utilities. This PRM construct breaks down in a 100% renewable system due to intermittency and non-dispatchability of supply and limitation of battery storage. As discussed earlier, the incremental contribution to reliability as measured by ELCC declines as more and more renewables and battery resources are added. Oversizing the resource base may reduce the risk, but the cost will go up and the risk of supply shortage will stay during occasional long periods of time without wind or sun. The utility industry is still developing resource adequacy criteria for a 100% renewable portfolio. Platte River will continue to work internally and track industry progress in developing a reliability metric for a 100% renewable portfolio. In the absence of any standards, Platte River used the criteria of minimizing unserved energy to select an acceptable resource mix for its 100% renewable portfolio.

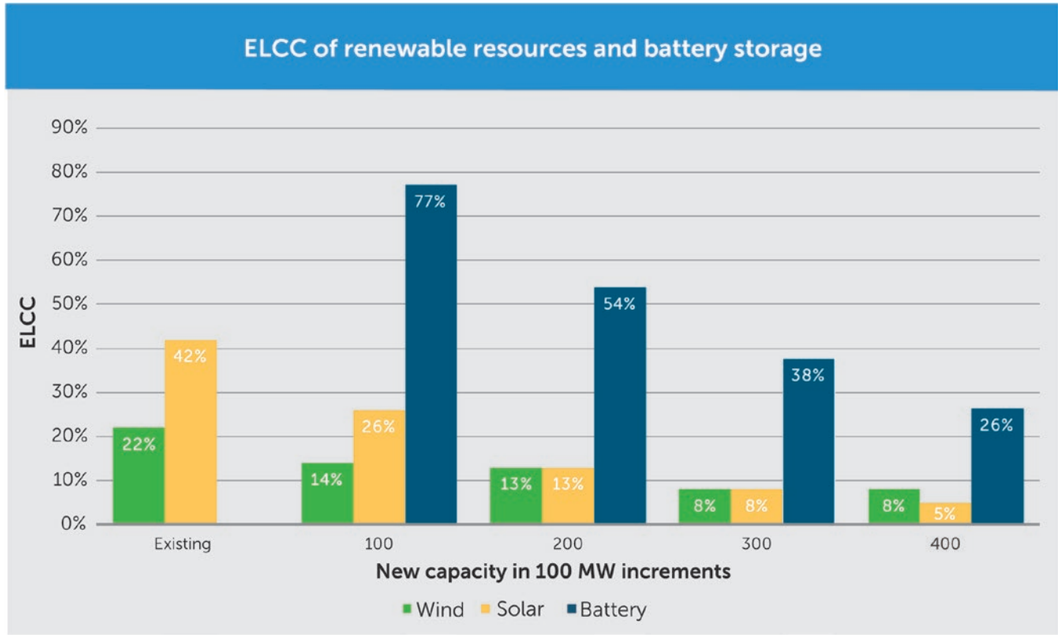


Figure 8-4

8.2 Need for new resources

The need for new resources can be assessed by reviewing future capacity and energy balance charts. The future capacity balance chart includes the forecasted annual peak demand plotted against the capacity contribution of each of the existing and committed resources. Figure 8-5 shows the capacity balance of Platte River for the duration of the planning period. It shows the forecasted capacity requirement and the capacity contribution of all existing resources. The capacity requirement shown by a thick black line includes the annual peak demand plus the 15% PRM required for reliability. On the supply side, summer capacity of all the available resources is shown as area charts. For thermal resources, their actual summer capacity is shown, while for renewable resources, their ELCCs are shown in the chart. It is clear Platte River does not need new capacity until both Craig units are retired by the end of 2028.

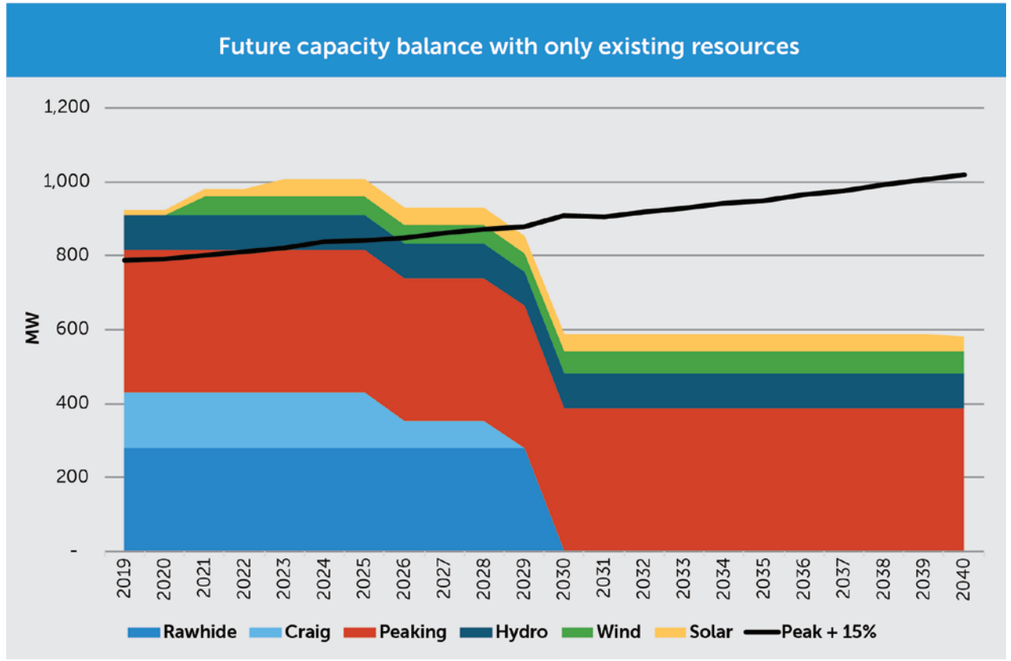


Figure 8-5

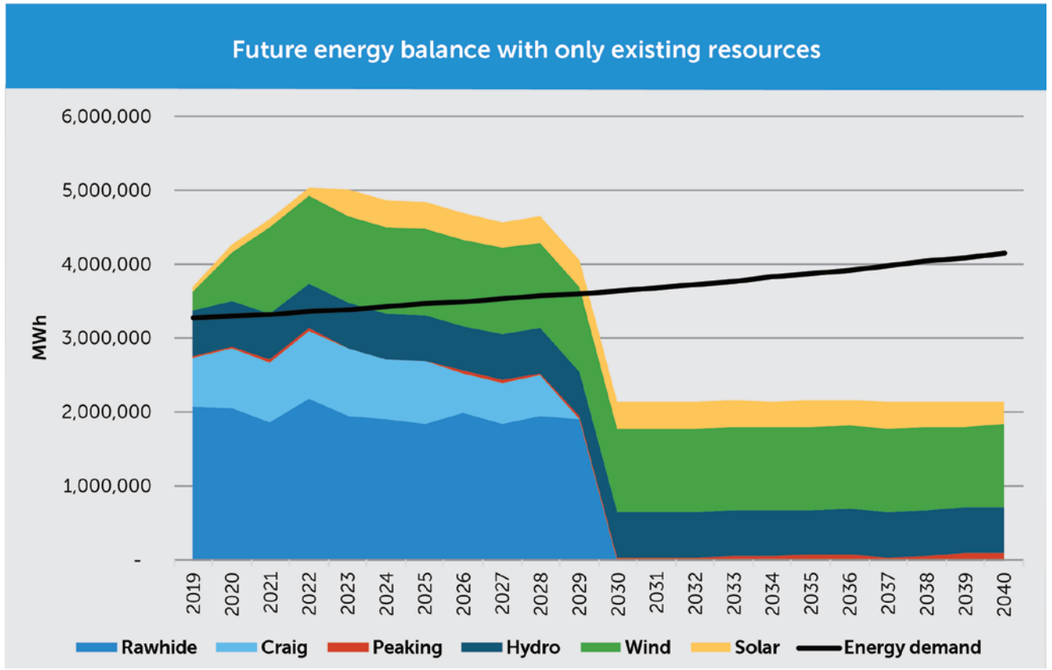


Figure 8-6

Platte River's expected energy balance over the planning horizon is shown in Figure 8-6. The energy demand in this chart is the net of DERs. On the supply side, solar, wind and hydro resources show their average generation while thermal resources produce at their expected economic levels. Figure 8-6 illustrates that for the next few years, Platte River will have excess energy available for export when wind and solar are producing at the average expected levels. After the retirement of coal-fired generation, Platte River will need new energy resources.

Platte River's Resource Diversification Policy calls for providing 100% noncarbon energy to its owner communities by 2030, subject to certain conditions being met. To achieve this goal, all thermal generation resources must be retired by 2030. Figures 8-7 and 8-8 show respective capacity and energy balance charts following the retirement of all carbon emitting resources by 2030. It is clear from these charts that significant amounts of renewable resources and battery storage will be required when thermal resources are retired.

Platte River's future energy and capacity needs, along with all the supply-side assumptions discussed in Chapter 6 were placed into the Aurora model (see Appendix D for more details of the model). This model develops an optimal resource plan, economically adding new resources or retiring existing resources to reliably meet Platte River's future electricity needs.

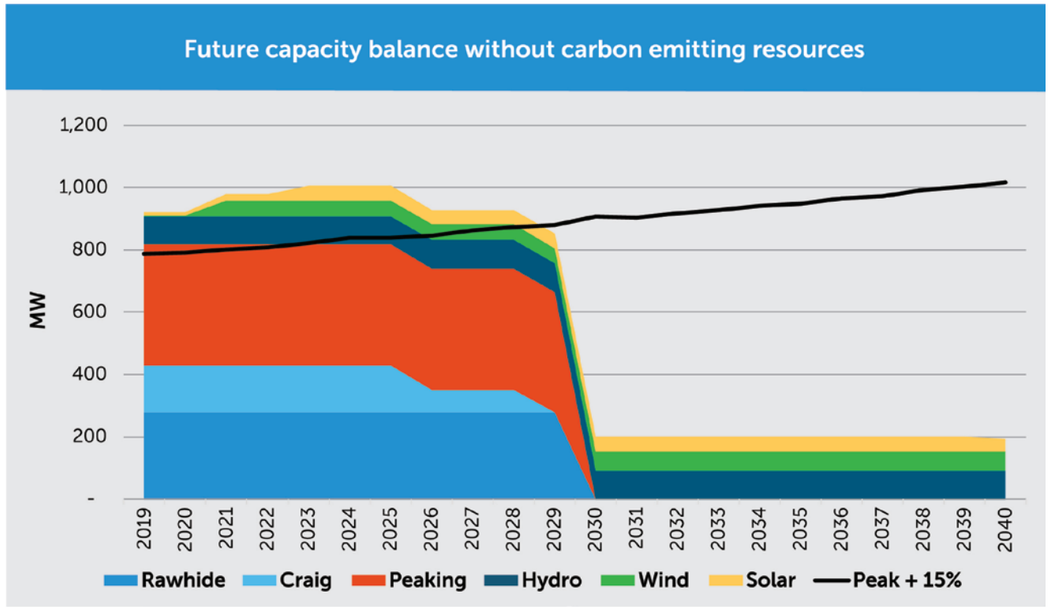


Figure 8-7

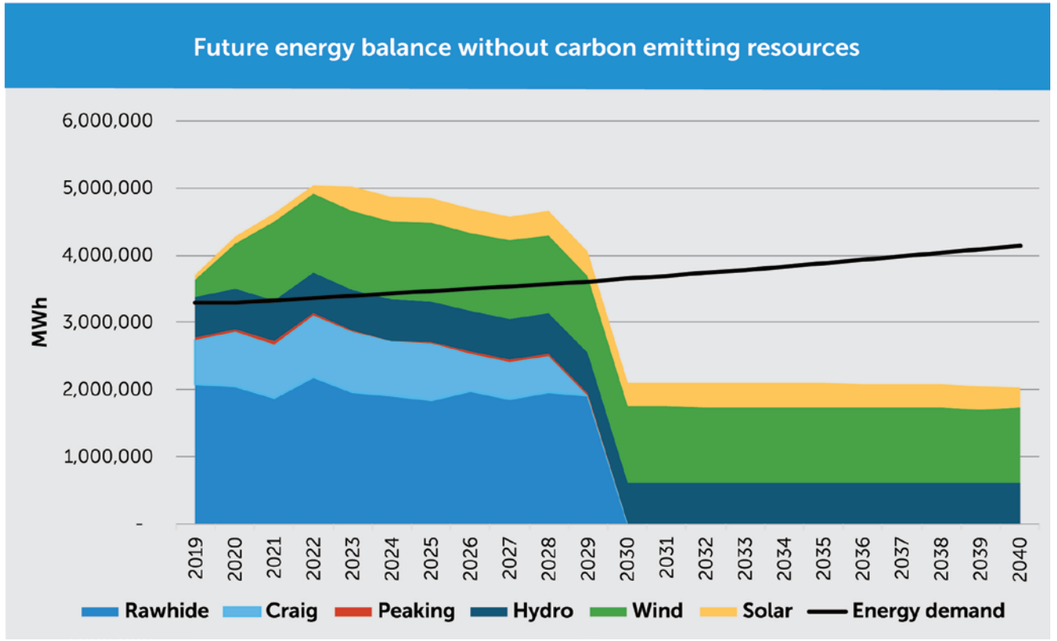


Figure 8-8

8.3 Development of future portfolios

Using various combinations of assumptions related to demand, supply, regulation and technology evolution, Platte River developed four different energy supply portfolios for this IRP, all of which consider the following inputs and assumptions:

- Commodity prices (gas, coal and power)
- Economic expansion in the communities and demand growth
- Pace of renewable and battery technology price evolution
- Pace of technology adoption by the suppliers and consumers of electricity
- Pace of DER adoption by customers
- Governmental policies regarding taxes, incentives and the environment
- Public expectations and adoption of noncarbon technologies
- Power market development in the region
- Development of the distribution grid and requirements of wholesale supply-side reliability
- Board's adopted Resource Diversification Policy

With these considerations in mind, Platte River selected the following portfolios for this IRP.

P1: continuity

This portfolio explores the path of continuing the current policy of reliably meeting owner communities' load obligations by adding new resources or retiring existing resources economically. Following the announcement of plans to retire Rawhide Unit 1 by 2030, the key assumption of no forced retirements has been superseded in this portfolio. However, this portfolio provides valuable baseline projections to measure the cost and environmental impact of assumptions and decisions in other portfolios.

P2: zero coal

This portfolio explores the path where Platte River retires all coal fired generation by 2030 while continuing the current policy of reliably meeting owner communities' load obligations. New resources are added economically while continuing to meet all current environmental regulations.

P3: zero carbon

This portfolio explores the path where Platte River retires all thermal generation by 2030 while continuing the current policy of reliably meeting owner communities' load obligations. New renewable resources and battery storage are added to develop a zero carbon supply portfolio.

P4: integrated utilities

This portfolio explores a future where technology evolution accelerates and new technology costs drop faster than current projections. Consequently, renewables, battery storage, EV and DER penetrate at a faster pace. For example, the costs of solar, wind and battery technologies in this portfolio are 15-25% lower relative to the first three portfolios. Similarly, distributed solar and EVs reach double the level relative to portfolios 1-3. Finally, other DERs also penetrate at a higher rate. While this energy transition is manifesting at an accelerated pace, Platte River adheres to its core pillars of reliably meeting owner communities' load obligations with the lowest-cost resources.

Similar to P1, the key assumption of no forced retirements has been superseded in this portfolio following the announcement of plans to retire Rawhide Unit 1 by 2030. However, this portfolio provides valuable insight on the impact of faster electricity transition with lower cost of renewables and higher DER penetration.

A detailed summary of the individual portfolios with associated assumptions and challenges is provided in the following section.

8.4 P1: continuity

The continuity portfolio is the least-cost option. This portfolio provides important insight about which resources are the most valuable and how their value may change over time. The Aurora model minimized the total cost of the system by retiring existing units when beneficial and adding new thermal, wind, solar or storage when required.

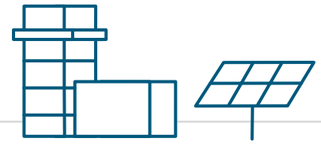
Modeling details

The Aurora model was run without any forced constraints on resource additions or retirements and an optimal portfolio was produced. That portfolio was then adjusted to reflect the expected retirement date of Craig 2 and reoptimized to give a least-cost solution while meeting the reliability requirement. Next, some early resource addition dates from this portfolio were adjusted to better coincide with the expected Craig retirement and a final optimization was run. As changes were made, the cost impact was monitored to ensure the portfolio still reflected a least-cost approach. The resulting portfolio is an actionable plan based on current expectations.

As part of the modeling process, additional demand-side resources were also tested. The medium DER potential proposed by HDR Inc. was not cost-effective, so the final portfolio reflects current base level of DER assumptions that were already included in the load forecast.

Finally, existing hydro and renewable resources were allowed to operate according to their schedules, without any change or retirement, over the full planning horizon.

8.5 P2: zero coal



The zero coal portfolio was designed to test the impact of retiring Rawhide Unit 1 earlier than its economic life. As a starting point, the model was allowed to retire the unit whenever economical during the planning period of 2021 through 2040. But the model didn't retire it, indicating that the early retirement was not the least-cost solution. Then the coal unit was forced retired at the end of 2029. Reliability was maintained through adherence to a 15% planning reserve margin and the balance of the portfolio was constructed to minimize costs. The model was allowed to economically add new gas-fired generation as well as wind, solar and battery storage resources.

Modeling details

For this portfolio, candidate capacity expansion plans were summarized across various metrics, including overall cost, renewable energy penetration, excess renewable energy that could not be sold to the market, the volume of surplus sales, and tons of carbon emitted.

Balancing the benefits of higher renewable energy production and lower carbon against the risks of dumping excess energy and high volumes of surplus sales while minimizing costs required multiple iterations. The optimization process found the least-cost option that met the reliability criteria while keeping the excess energy sales at a reasonable level. With each iteration, the expansion plan was slightly altered to better balance the metrics followed by a new optimization test. Alterations were made to the year or size (or both) of the resources added. The goal was to use analytical judgment to test resiliency of P2 where necessary but rely on the model to optimize where possible. The resulting P2 was the least-cost option (among the various options tested) and was very competitive across every other metric. This portfolio also relied on the existing levels of DERs because higher levels were not economic when tested in the model.

8.6 P3: zero carbon

The zero carbon portfolio was designed to meet the goal of producing all energy from noncarbon resources starting in 2030. Consequently, all thermal units were retired and replaced with wind, solar and battery resources. Hydro allocations were retained so the noncarbon energy mix is a combination of wind, solar and hydro, along with batteries used to store excess energy during periods of high noncarbon production for use during periods when renewable resources cannot fully meet demand. In this portfolio, retirement of all thermal resources required significant additions of renewable resources and battery storage, with large amounts of excess renewable energy during hours of high wind and/or solar generation. While a PRM of 15% is sufficient for Platte River with a mix of thermal and renewable generation, with 100% noncarbon generation the reliability requirement needed additional analysis, as discussed later in this section.

Modeling details

Development of a 100% noncarbon portfolio was an iterative process. The criteria used to select a resource plan for this portfolio aligned with Platte River's three pillars. Reliability was measured by tracking the amount of energy that could not be served by a given combination of resources. If Platte River's wind, solar, hydro and battery resources were not able to provide enough energy to meet demand, then Platte River would need to procure that energy from neighboring systems. The plans with heavy reliance on neighboring systems were less reliable and less predictable than plans that were able to serve load with Platte River's own resources[10].

Environmental responsibility was implicitly assumed in this portfolio because all energy would be produced from noncarbon resources starting in 2030. Plans that produced significant amounts of excess energy were deemed less financially sustainable because excess energy not sold in the regional market would need to be curtailed. Without energy storage, this energy could be wasted. Plans with less excess energy were ranked as more environmentally and financially responsible than other plans. Net present values of total plan costs were also used to measure financial sustainability over time, with lower net present values representing better financial sustainability.

A grid search was performed on many combinations of solar, wind and battery resources to identify competitive energy mixes. Each combination was placed into a production cost model to measure its costs, reliability and excess renewable energy. Once these measures were recorded, the portfolios were compared based on these measures.

Challenges of zero carbon portfolio

Intermittency of wind, time-limited availability of solar and a finite amount of battery storage are the main challenges to reliably meet customer demand in the absence of dispatchable thermal resources. Ensuring reliability of supply during periods of extended cloudy days with low or no wind, also referred to as "dark calms," would require a very large bank of batteries which may become uneconomical. A dark calm experienced in Platte River's service territory during January 2018 is illustrated in the figure below.

Figure 8-9 displays output of wind and solar resources as a percentage of nameplate capacity over the course of five days. This data was used to test the amount of battery storage needed to serve load during periods of low generation. Due to low wind and solar generation in the first few days, battery discharging was required to meet load. The battery was unable to fully recharge due to continued low wind and solar generation, causing reliability challenges during the night between the fourth and fifth days when there was no solar or wind generation and the batteries were depleted. To reliably serve customer needs during extended low generation periods would require a very large battery bank. Staff currently do not have enough historical data to determine the worst-case scenario for wind and solar during similar shortages for multiple years. In the absence of such credible historical data, the NERC recommended generation reliability planning criteria of allowing no more than a one-day outage in 10 years or 2.4 hours in one calendar year would be hard to meet.

January 2018 wind and solar generation profile – the dark calm

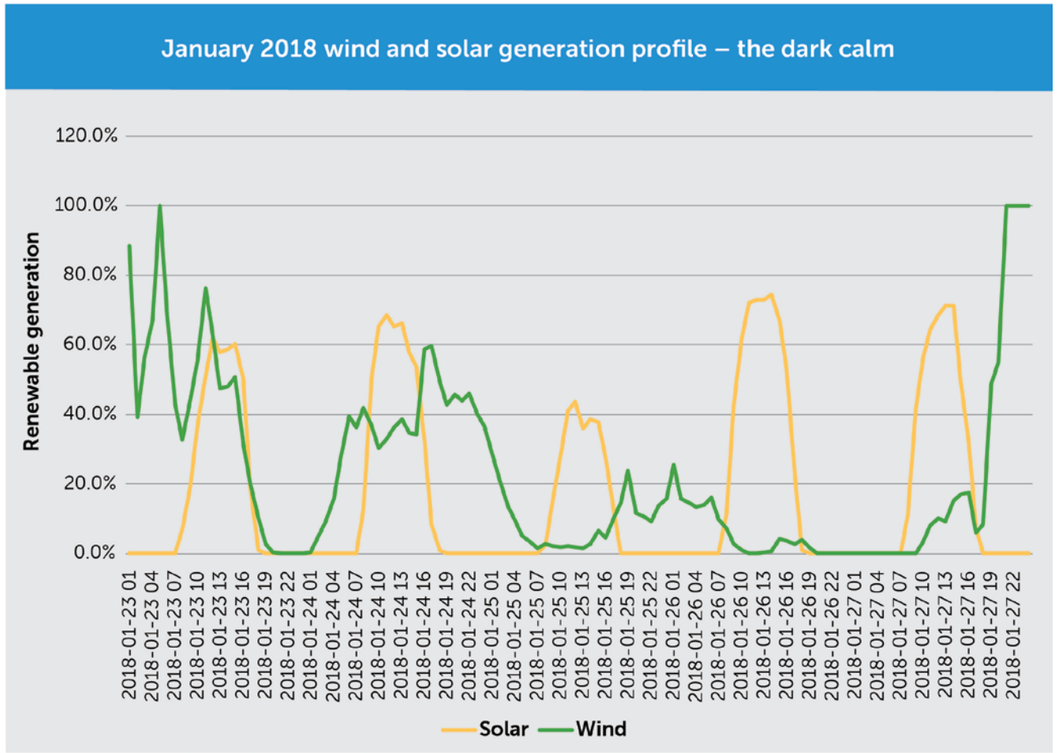


Figure 8-9

[10] In a 100% renewable scenario, availability of emergency energy from neighboring systems is less certain due to less diversity of weather patterns across neighboring areas. When a big weather system moves through the area, it can impact a large geographic region. For example, it could be cloudy in a large geographic territory, thereby reducing solar energy production across the region.

The zero carbon portfolio is highly dependent upon the renewable generation profiles assumed in the study. If wind and solar hourly generation profiles are averaged over multiple geographic regions, they are less susceptible to dark calms. Using broader geographical profiles also requires fewer storage resources to provide reliability through periods of low generation. With less geographic diversity, storage requirements drastically increase because single sites are more susceptible to long stretches of little wind generation versus a portfolio of generation spread across a larger region. This will be an area of focus in future studies to determine the cost effectiveness of more diverse renewable portfolios.

In a test example, switching from a diverse regional profile to a single site profile resulted in a more than 50% increase in the amount of storage required to serve load. This additional storage would have only served around 100 hours of load over the course of a year, meaning that most of the time the batteries could not have been used. This test example highlights the potential tradeoffs between the environmental cost of additional batteries compared to the environmental cost of thermal generation to provide reliability during occasional dark calms. Planning for a reliable portfolio with 100% renewable resources requires careful evaluation of the following assumptions:

- Can the renewable generation resources be spread over a large enough region for weather diversity to minimize the probability of dark calms?
- Can the market or neighboring utilities be relied upon to provide emergency support and reliability during dark calms?
- What is the maximum support expected from participating in a regional market?

Traditional reliability metrics like planning reserve margins do not adequately address reliability concerns with a 100% noncarbon energy portfolio. Reliability metrics need to be redefined and further analysis of renewable generation should be performed to measure the risk associated with dark calms. This work must also include a market study that examines how much a market can mitigate the risk of dark calms. Finally, future work should address the tradeoffs between the financial and environmental costs of a large new battery bank versus keeping the existing thermal peaking generation to provide reliability during periods of dark calm.

8.7 P4: integrated utilities

The integrated utilities portfolio assumes a faster rate of technological progress, accelerating the energy transition with higher distributed solar generation and EV penetration as well as the implementation of additional DER programs. This portfolio also assumes lower costs for wind, solar and battery resources relative to those used in portfolios 1-3. Figure 8-10 shows the cost of these resources in P4 relative to the cost in P1-P3. For example, cost of solar in P4 is 18% lower in 2030 and 20% lower in 2040 relative to the cost of solar in P1-P3.

P4 renewables and battery costs relative to P1-P3		
	2030	**2040**
Solar	-18%	-20%
Wind	-14%	-14%
Battery	-27%	-33%

Figure 8-10

Due to the lower resource price trajectories, the integrated utilities portfolio assumed twice the amount of distributed solar capacity and twice the number of EVs by 2040. These assumptions impact the load forecast in different ways as shown in the following two tables and discussed in detail in Appendix E. Figure 8-11 shows the impact of distributed solar, EVs, energy efficiency and demand response programs on the annual peak demand in 2030 and 2040 for P1-P3 and P4. It can be seen that distributed solar reduces peak demand by 3% in P1-P3 (from the base forecast) while it reduces the peak by 5% in the case of P4 due to higher distributed solar adoption. Similarly, EVs increase peak demand by 3% in 2040 for P1-P3 while the peak demand increase is 7% in the case of P4 due to higher penetration.

DER impact on peak demand forecast				
	P1-P3		**P4**	
	2030	**2040**	**2030**	**2040**
Distributed solar	-3%	-3%	-5%	-5%
EVs	1%	3%	2%	7%
Energy efficiency and demand response	-1%	-1%	-3%	-3%
Total	-2.7%	-0.3%	-5.6%	-1.0%

Figure 8-11

DER impact on energy forecast				
	P1-P3		P4	
	2030	2040	2030	2040
Distributed solar	-3.6%	-3.7%	-7.7%	-7.5%
EVs	2.1%	9.0%	4.4%	18.1%
Energy efficiency and demand response	-8.8%	-12.0%	-11.1%	-14.4%
Total	-10.4%	-6.8%	-14.5%	-3.8%

Figure 8-12

Figure 8-12 shows the change in energy consumption due to different DERs for P1-P3 and P4. It is interesting to note that the net change in energy consumption in P4 relative to P1-P3 is higher in 2030 (-14.5% vs. -10.4%) but lower in 2040 (-3.8% vs. -6.8%) due to higher EV penetration in P4.

Challenges and future work for integrated portfolio

P4, with a higher level of DERs, will require a complex interaction between the customers and the power suppliers, both at the distribution level and at the wholesale level. First of all, the traditional one-way flow from the suppliers to the customers will not hold true as some consumers may become prosumers (producers and consumers) on a regular basis. Managing distribution-level resources with renewable generation fluctuations at the wholesale level will require more integration and coordination between Platte River and its owner communities. A key facet of this integration will be the real time data sharing with customers whereby they can use flexible demand sources when higher levels of renewables are available. As discussed in Section 6.9, Platte River and the owner communities recently initiated a DER strategic planning process. Through this process, Platte River and its owner communities intend to address the key issue of integration and collaborate to develop a common vision and set of objectives and initiatives.

While there will be many operational challenges of integrating high level of DERs, a key challenge during the planning phase is to model customer behavior with future technologies where little or no data is available, i.e., EV charging. Data concerning how much charging can be curtailed when costs are high or how much charging load will be available during periods of high renewable energy generation is unknown at this time. Additional analysis is required to improve modeling of discharging EVs to meet load requirements and to improve forecasting expected energy storage from EVs. Also, it is unclear how the customers will change their usage patterns if new rate structures like time-of-day rates or real time market price-based rates are adopted by the owner communities.

Other challenges include modeling potential load growth driven by the adoption of beneficial electrification policies, such as switching to electric hot water heaters and heat pumps, currently under consideration in the owner communities. This additional load may also require the owner communities to upgrade some distribution circuits and transformers while Platte River would need to acquire additional supply side resources.

9 IRP results

This chapter evaluates IRP modeling results and important features of the four portfolios with a focus on Platte River's three pillars of reliability, environmental responsibility and financial sustainability. Modeling results, including new resource additions, CO_2 reduction and costs for each of the four portfolios are discussed first. This is followed by a sensitivity analysis to test the resilience of each portfolio under differing values of major input assumptions. A qualitative summary concludes this chapter, followed by recommendations in Chapter 10.

9.1 Portfolio expansion plans

The four portfolios discussed in this IRP were developed to cover a wide spectrum of future possibilities. These four portfolios represent four snapshots of unique paths into the future. The following pages compare the capacity additions and retirements for different resource types in each of the four portfolios. Resource types are presented in alphabetical order. When a resource type retires, its capacity is reduced to zero. Capacity resources added as part of this IRP are labeled with "(new)". For example, existing solar resources are labeled as "solar" while the solar resources added as part of this IRP are labeled as "solar (new)".

Due to relatively low demand growth, none of the four portfolios add any new resources through 2028. From 2030 through 2040, the four portfolios add different amounts of resources. While this IRP does not add new resources prior to 2028, Platte River staff will continue to evaluate options to progressively add economical new resources to advance toward a 100% noncarbon supply mix while maintaining three pillars of reliable, environmentally responsible and financially sustainable energy and services.

P 1: continuity
Capacity expansion plan

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
CTs	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388
Craig	151	151	151	151	151	74	74	74												
Hydro	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91
RH1	278	278	278	278	278	278	278	278	278	278	278	278	278	278	278	278	278	278	278	278
Solar	55	55	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	135
Solar (new)																100	100	100	100	100
Storage									50	50	50	50	100	100	100	100	100	150	150	200
Wind	231	231	231	231	231	231	231	231	225	285	285	285	285	285	285	285	285	285	285	285
Wind (new)									100	100	100	100	100	100	100	100	100	100	100	100

Figure 9-1

The **continuity portfolio** adds 100 MW of wind and 50 MW of battery storage capacity[10] in 2029 following the anticipated retirement of Craig 2 in 2028[11]. Rawhide Unit 1 and the combustion turbines remain in service through the end of the planning horizon. No additional thermal resources are added into this portfolio. As load grows, more battery storage capacity and renewable energy resources will be added to meet reserve margin and incremental energy requirements.

[10] All battery storage units are modeled with 4-hour storage capability. So, a 50 MW battery storage block has 200 MWh energy capacity.

[11] For this analysis, Craig 2 was assumed to retire on Dec. 31, 2028. On July 8, 2020, owners announced the retirement date as Sept. 30, 2028. This minor difference will not change the results or conclusions of this IRP.

P2: zero coal
Capacity expansion plan

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
CTs	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388
Craig	151	151	151	151	151	74	74	74												
Hydro	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91
RH1	278	278	278	278	278	278	278	278	278											
RICE										104	104	104	104	104	104	104	104	156	156	156
Solar	55	55	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	135
Solar (new)										300	300	300	300	300	400	400	400	400	400	400
Storage									100	300	300	300	300	350	400	400	450	450	450	450
Wind	231	231	231	231	231	231	231	231	225	285	285	285	285	285	285	285	285	285	285	285
Wind (new)									100	200	200	200	200	200	200	200	200	200	200	200

Figure 9-1

The **zero coal portfolio** adds 100 MW of wind and battery storage in 2029 following the anticipated retirement of Craig 2 in 2028, but significant rebalancing occurs when Rawhide Unit 1 retires in 2030. At that time, the baseload unit is replaced with 104 MW of RICE, 100 MW of wind, 300 MW of solar and 200 MW of battery storage. Following this rebalancing, more resources are added to meet anticipated demand growth, including 52 MW of RICE, 100 MW of solar and 150 MW of battery storage in later years. Gas-fired RICE generation with high level of flexibility complements renewable intermittency and provides back up during low renewable generation to ensure high level of reliability to the customers. Based on today's projections, RICE generation is the least cost option to provide reliability. If there is a technological breakthrough and a lower cost alternative is available to provide the same level of flexibility and reliability before the investment decision is made, Platte River will consider it.

P3: zero carbon
Capacity expansion plan

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
CTs	388	388	388	388	388	388	388	388	388											
Craig	151	151	151	151	151	74	74	74												
Hydro	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91
RH1	278	278	278	278	278	278	278	278	278											
Solar	55	55	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	135
Solar (new)										750	750	750	750	800	800	800	800	800	850	850
Storage									100	2400	2400	2400	2450	2450	2500	2550	2550	2600	2600	2600
Wind	231	231	231	231	231	231	231	231	225	285	285	285	285	285	285	285	285	285	285	285
Wind (new)									100	550	550	550	550	550	550	550	600	600	600	600

Figure 9-1

The **zero carbon portfolio** adds 450 MW of wind, 750 MW of solar and 2,300 MW of battery storage capacity to replace all the thermal resources. This level of battery storage would approximately serve the average Platte River demand for a period of 24 hours. While this would be enough to cover the dark calm events experienced in 2018, it would not be able to provide the reliability that a thermal system can provide with 15% of PRM. More analysis is required to understand the reliability risks associated with this portfolio, including the potential reliance on outside purchases during dark calm periods when neighboring utilities could face energy shortages due to weather similarities. Because no broad energy market currently functions in the region and because neighboring utility plans concerning noncarbon resources are expected to be somewhat similar, it is difficult to model broader market dynamics.

P4: integrated utilities
Capacity expansion plan

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
CTs	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388
Craig	151	151	151	151	151	74	74	74												
Hydro	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91
RH1	278	278	278	278	278	278	278	278	278	278	278	278	278	278	278					
RICE																104	104	156	156	156
Solar	55	55	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	135
Solar (new)																400	500	500	500	500
Storage									100	100	100	100	100	100	100	400	400	400	400	400
Wind	231	231	231	231	231	231	231	231	225	285	285	285	285	285	285	285	285	285	285	285
Wind (new)									100	100	100	100	100	100	100	200	200	200	200	200

Figure 9-1

The **integrated utility portfolio** shows how Platte River may progress in a rapid energy transition future. This portfolio sees aggressive transportation electrification, high level of DER penetration and accelerated technology improvements resulting in lower prices for renewable resources and battery storage. Like the continuity portfolio, this portfolio relies on the least-cost approach to planning with no forced constraints (in contrast to the forced retirements in P2 and P3). Under this portfolio, Rawhide Unit 1 is economically retired in 2036 due to rapidly falling renewable and storage costs. At that time, this portfolio behaves like P2 and adds 104 MW of RICE for ensuring reliability and adds renewables and batteries to provide lower-cost energy.

9.2 Portfolio costs

Figure 9-2 shows annual generation costs for each of the four portfolios. Generation cost includes fuel, O&M, power purchase costs and netted for sales revenue. These costs do not reflect the full annual revenue requirements Platte River must collect from its owner communities. As noted previously, supply portfolios remain the same before 2029, resulting in cost curves that are similar as well. In 2030, the cost curves diverge based on the resource mix of each portfolio. Clearly visible, the zero carbon portfolio costs are significantly higher due to mandated replacement of all thermal resources, which undermines Platte River's core pillar of financial sustainability.

Generation costs of the remaining three portfolios are relatively closer together and follow approximately similar trajectories as shown in Figure 9-3. Cost of the zero coal portfolio rises in 2030 due to the new investment required to replace Rawhide Unit 1. The integrated utilities portfolio also sees a cost increase in 2036 following the retirement of Rawhide Unit 1, but this increase is smaller due to the lower costs of solar, wind and battery storage in this portfolio. By 2040 costs of the three portfolios converge within a 3% range. Around that time, the cost of the continuity portfolio is rising at a higher rate relative to the other two portfolios due to the impact of CO_2 taxes and fuel costs.

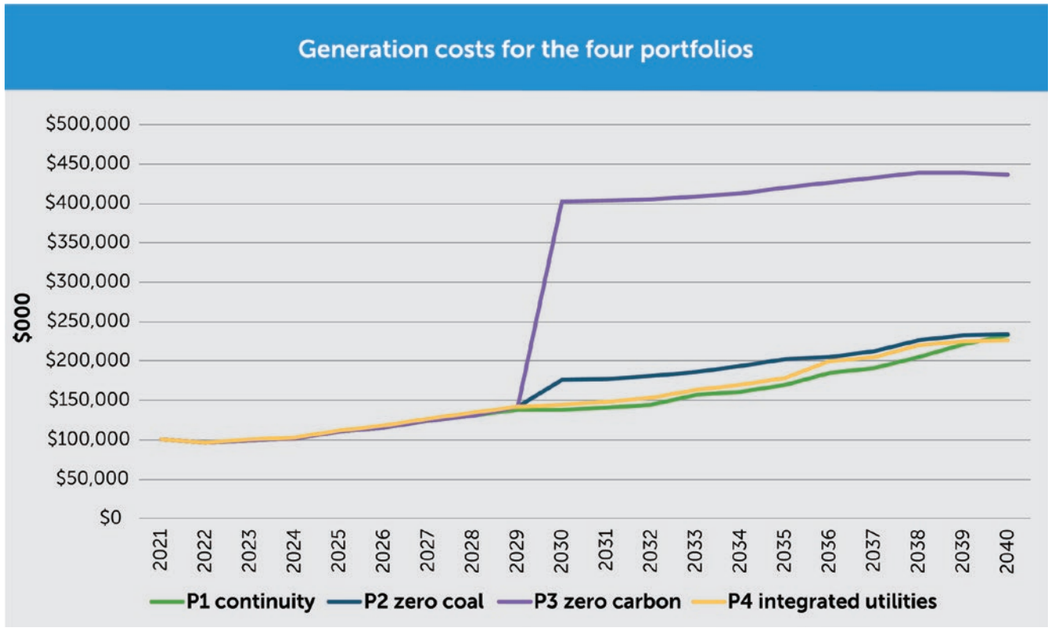


Figure 9-2

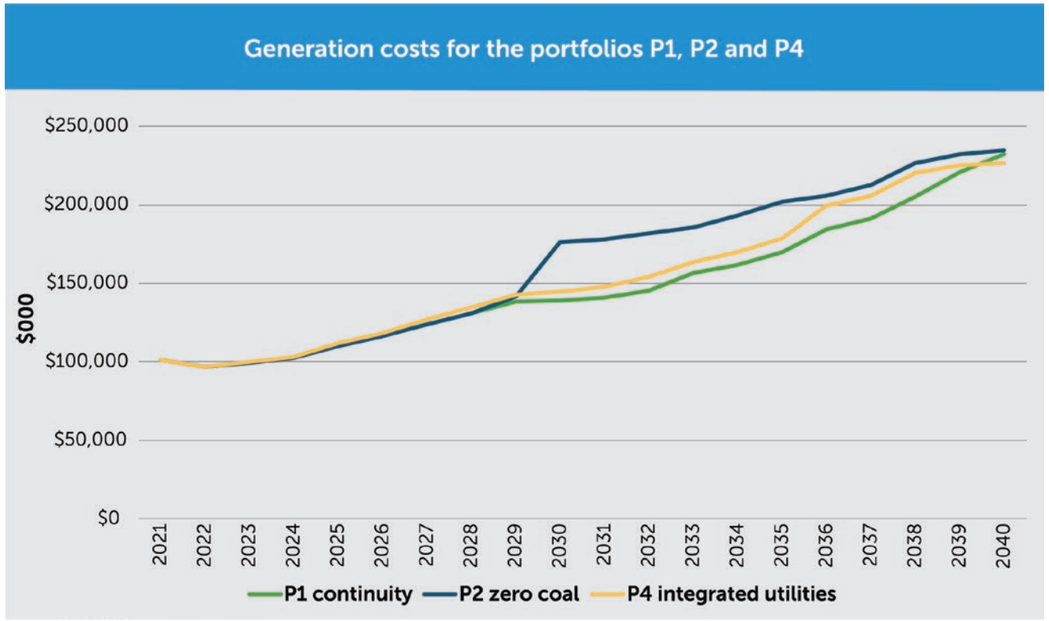


Figure 9-3

9.3 Portfolio wholesale rates

Platte River's rate setting policy calls for established service offerings and supporting rate structures that complement the strategic objectives and values of the organization, all aligned with its three pillars. Platte River's strategic financial plan (financial plan) provides a roadmap for long-term financial sustainability, financial risk management and support for Platte River's vision, mission and values. Platte River has established the following financial plan metrics in consideration of rating agency guidelines.

- Generate minimum 1.5 times fixed obligation charge coverage ratio
- Generate minimum net income equal to 3% of projected annual operating expenses
- Target debt ratio less than 50%
- Target minimum 200 days unrestricted cash on hand

The IRP rate analysis used a financial model that integrates the Aurora model outputs with other operating costs to project earnings, liquidity, debt and cash flows relative to financial plan targets over the IRP planning horizon. This process identifies future debt issuance and revenue requirements, thus projecting future rate increases. Key financial assumptions in the IRP rates analysis are as follows:

- PPAs were assumed for new wind, solar and battery storage additions.
- Battery storage PPAs were assumed to be a fixed obligation due to storage resources' nature as capacity resources with high fixed costs. Therefore, 1.5 times fixed obligation charge coverage ratio included battery storage PPA expense.
- Depreciation was accelerated for units retired before the end of their projected useful lives.
- Decommissioning costs for the Rawhide and Craig power plants were amortized annually until sites are decommissioned.
- Personnel transition costs were not included.
- Fossil fuel-based new resources were assumed to be owned and financed with debt when necessary to achieve financial plan targets.

Figure 9-4 shows future wholesale rate projections for the four portfolios. Rate smoothing strategies were incorporated into the rate projections to avoid large single-year rate increases or to accomplish specified financial objectives.

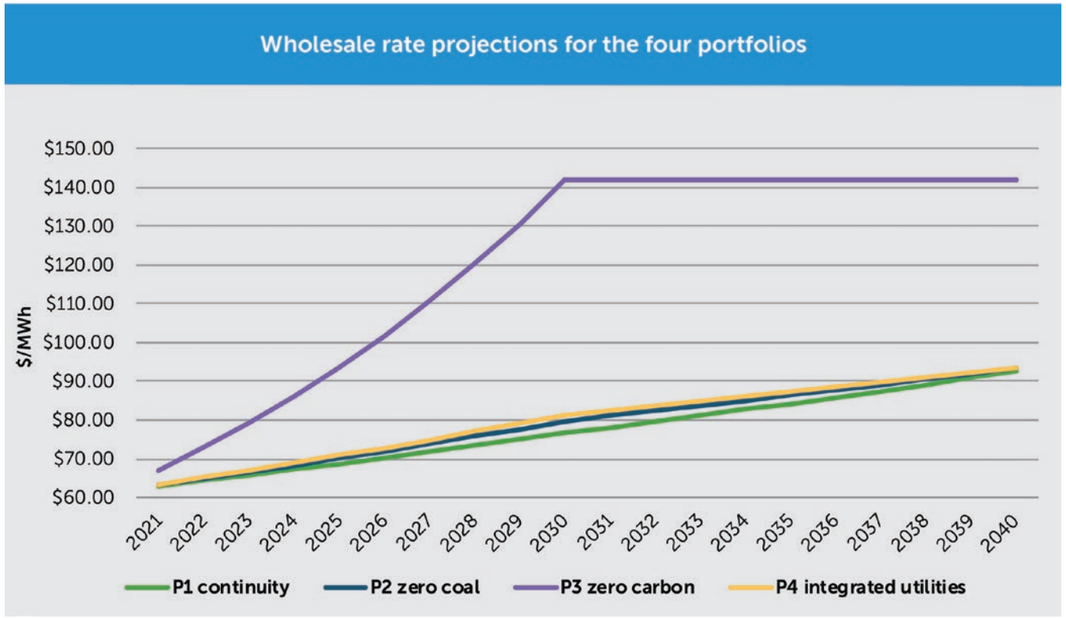


Figure 9-4

The **continuity portfolio** has the lowest projected rates over the long term. Rate drivers from 2020 to 2040 include purchased power expenses covering market prices and PPAs for wind, solar and battery storage resources. Additionally, CO_2 taxes contributed to rate pressure starting in 2025.

The **zero coal portfolio** retires all coal units but maintains the existing natural gas combustion turbines and projects RICE natural gas unit additions in 2030 and 2038 for reliability. These RICE units were assumed to be built and owned by Platte River. Purchased power is the most significant rate driver from 2020 to 2040, including increased wind, solar and battery storage. The average rate in the zero coal portfolio is roughly $3/MWh more than the continuity portfolio in 2030 and about the same in 2040.

The **zero carbon portfolio** eliminates all CO_2 operating emissions by retiring all coal and natural gas generation resources by 2030. Replacement energy and capacity resources include wind, solar and a significant amount of battery storage. To avoid a large rate increase in 2030, Platte River would begin implementing 8.7% average annual rate increases from 2021 to 2030. This increase leads to 2030 rates that are $65/MWh higher relative to the continuity portfolio. Although there are minimal rate increases after 2030, zero carbon portfolio rates in 2040 remain approximately $49/MWh higher than the continuity portfolio in 2040.

The **integrated utilities portfolio** assumes higher levels of DERs and lower wind and solar prices. Following the retirement of Rawhide Unit 1 in 2035, RICE capacity would be added in 2036 for reliability purposes. Increases in DER resulted in lower projected sales, thus requiring increased rates to recover fixed costs. For these reasons, 2030 rates would be $4/MWh higher than the continuity portfolio.

The rate impacts seen in Figure 9-5 are higher leading up to 2030 due to rate smoothing and the need to build reserves to meet the financial plan requirements. These rate projections show the zero coal portfolio would require a modest increase over the continuity portfolio. The integrated utilities portfolio would require slightly higher rates through the first half of the planning horizon but lower impacts in the later years, with an average rate increase on par with the zero coal portfolio. For the zero carbon portfolio, an average year-over-year rate increase of 8.7% is needed until 2030 and 0.0% increase from 2031 until 2040 for an average rate increase of 4.3% per year over the horizon of the study. Most of the rate increases in the zero carbon portfolio, relative to other portfolios, stem from the need to build a large amount of new, noncarbon generation and storage batteries to maintain reliability.

	Average annual growth rate			Cumulative growth rate		Rate	
	2021-2030	2031-2040	2021-2040	2021-2030	2021-2040	2030	2040
P1	2.2%	1.9%	2.0%	24.3%	50.1%	$77	$93
P2	2.6%	1.6%	2.1%	29.3%	51.5%	$80	$93
P3	8.7%	0.0%	4.3%	130.3%	130.3%	$142	$142
P4	2.8%	1.4%	2.1%	31.8%	51.5%	$81	$93

Figure 9-5 Wholesale rate comparison for the four portfolios

9.4 Portfolio CO_2 emissions

To measure environmental sustainability, Platte River reviewed CO_2 emissions from two different perspectives. First, reduction of CO_2 emissions relative to 2005 actual emissions, per Colorado standards, and, second, annual renewable energy as a percent of total annual energy supplied to the owner communities. These perspectives are discussed in sections 9.4.1 and 9.4.2. Section 9.4.3 gives a high level overview of recently enacted state legislation in Colorado; HB19-1261 and SB19-236.

9.4.1 CO_2 reduction relative to 2005 actual emissions

Figure 9-6 shows CO_2 reductions for the four portfolios relative to 2005 actual emissions. As in the case of generation costs, emission profiles of all the four portfolios are similar prior to 2030 because of similar resource mix. There is a steady decline in CO_2 emissions from 2021 through 2029 as the percent reduction relative to the 2005 baseline increases from 20% in 2021 to over 40% by 2029. This doubling of reduction is achieved through the gradual retirement of Craig coal units and addition of renewable generation. After 2029, P1 does not achieve any significant reduction. P2 sees emission reduction of above 90% in 2030 and beyond following the retirement of Rawhide Unit 1. P3 achieves 100% reduction with the retirement of all thermal generation in 2030. P4 experiences a large increase in emission reduction in 2036 following the retirement of Rawhide Unit 1.

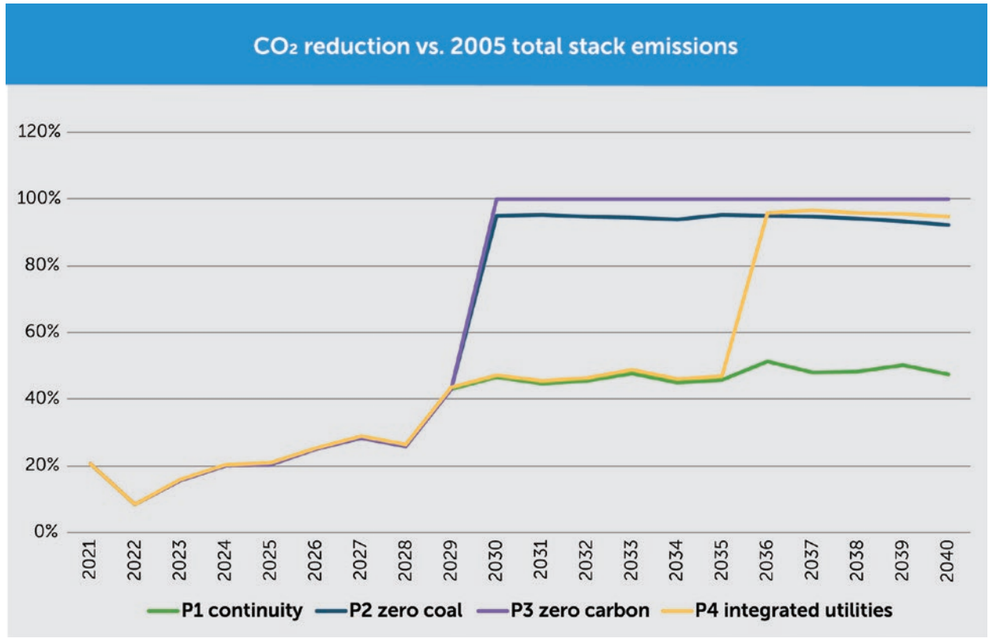


Figure 9-6

9.4.2 Percent renewable generation supplied

Figure 9-7 shows the amount of renewable or noncarbon generation as a percentage of total owner community load. All portfolios reach about 56% noncarbon supply by 2024, reduce slightly due to load growth and reach 65% by 2029 and then diverge. The continuity portfolio's noncarbon energy production percentage stays around 65% through the planning horizon, with minor changes due to load growth and new resource additions. The zero coal portfolio reaches 100% noncarbon generation by 2030 and then fluctuates around that value due to load growth and new resource additions. The zero carbon portfolio noncarbon generation rises much higher than 100% of owner community load due to the excess renewable resources required for reliability purposes. Finally, the integrated utilities portfolio follows the continuity portfolio until the retirement of Rawhide Unit 1 in 2036 and then stays above 100%.

As discussed in the supply-side assumptions chapter, 100 MW of new solar addition in 2024 was assumed from the currently on-going solicitation for 50-150 MW of new solar generation. From the initial review of the offers, it seems likely that 150 MW may be procured in this solicitation, increasing the level of carbon free energy initially assumed. Figure 9-8 shows the percentage of carbon free energy with 150 MW of new solar instead of 100 MW. With this increase, Platte River will be able to provide about 60% noncarbon energy by 2024, as seen in Figure 9-8.

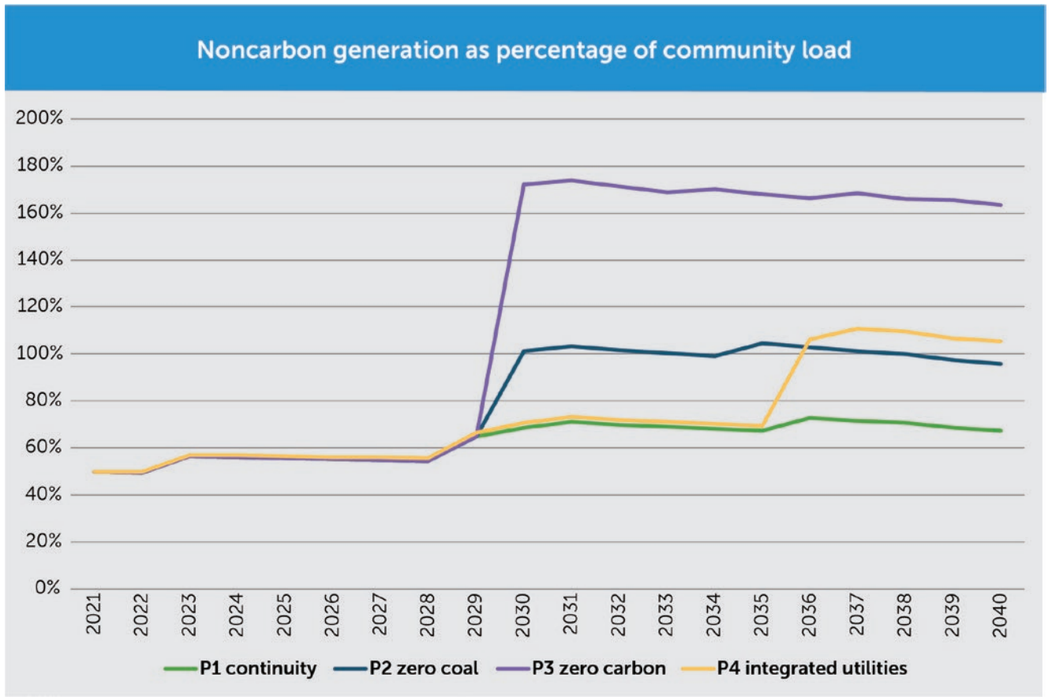


Figure 9-7

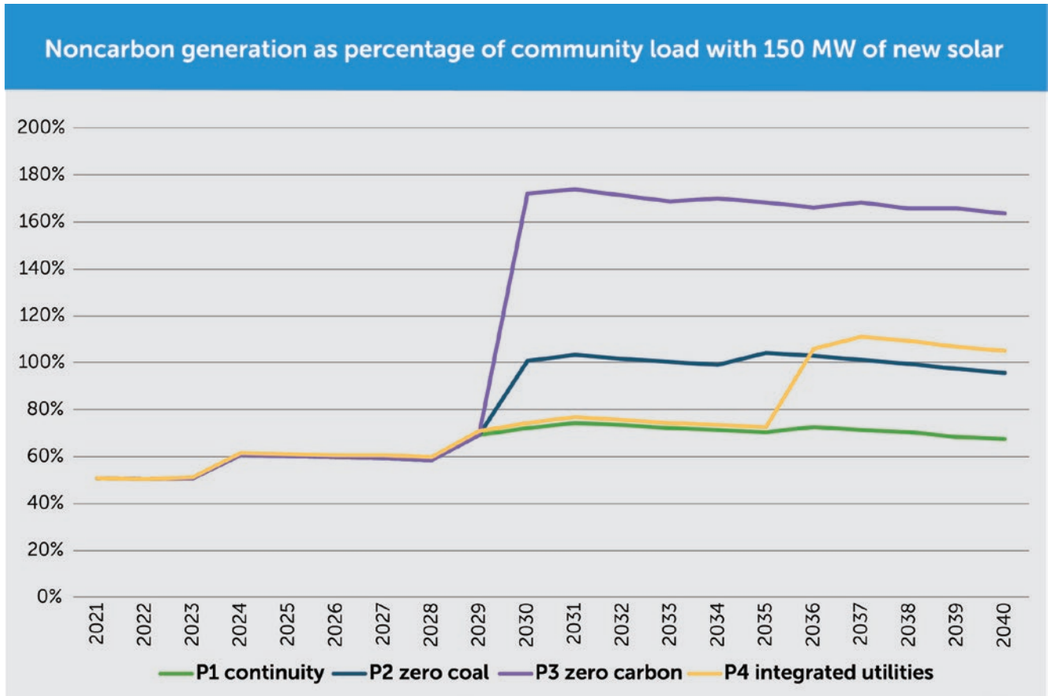


Figure 9-8

9.4.3 Colorado CO_2 legislation (HB19-1261 and SB19-236)

HB19-1261

Colorado House Bill 19-1261, titled Climate Action Plan to Reduce Pollution, establishes statewide goals to reduce 2025 greenhouse gas emissions by at least 26%, 2030 greenhouse gas emissions by at least 50%, and 2050 greenhouse gas emissions by at least 90% of the levels of greenhouse gas emissions that existed in 2005. It also specifies what the Colorado Air Quality Control Commission (AQCC) must consider when implementing policies and promulgating rules to reduce greenhouse gas pollution, including the benefits of compliance and the equitable distribution of those benefits, the costs of compliance, opportunities to incentivize clean energy in transitioning communities, and the potential to enhance the resilience of Colorado's communities and natural resources to climate impacts. In lieu of rulemaking, the bill permits utilities to voluntarily submit a clean energy plan (CEP) to the AQCC, as long as that plan commits to an 80% reduction in greenhouse gas emissions by 2030.

SB19-236

Colorado Senate Bill 19-236, also known as the Sunset Public Utilities Commission bill, requires among a host of other things, a qualifying retail utility to submit a clean energy plan, and allows any other electric utility to voluntarily submit a plan to the commission as part of its ongoing resource acquisition planning process to seek approval from the commission on how the qualifying retail utility plans to address clean energy targets established in the act.

As noted in section 9.4.1, P2 and P3 meet the requirements of voluntary reduction of CO_2 emissions by 80% by the year 2030 while P1 and P4 do not meet this voluntary requirement.

9.5 Sensitivity analysis

Sensitivity analysis refers to changing one or more assumptions used in developing the portfolio and analyzing resulting changes in different attribute of the portfolio. Sensitivity analysis is very important to test the robustness of portfolios under the circumstances when one or more key inputs or variables diverge from the assumed values. The sensitivity analysis considered the impact of two key assumptions: prices for CO_2 and natural gas.

9.5.1 Social cost of carbon sensitivity

The state of Colorado requires investor owned utilities to incorporate the social cost of carbon into resource planning decisions[12]. Following this guidance, Platte River analyzed the impact of adding the social cost of carbon for CO_2 emissions from thermal generation resources. To model this sensitivity, CO_2 tax of $4/ton starting in 2025 was replaced with the social cost of carbon of $46/ton in 2020 escalating at 3% per year. The social cost of carbon of $46/ton adds about $50/MWh to the dispatch cost which is more than three times the fuel cost of coal plants. With this large increase in cost, coal generation does not remain economical to operate. Consequently, all coal generation tends to retire when the social cost of carbon is added, provided enough renewables and other resources are available to reliably meet customer load. If this sensitivity was run unconstrained, all coal generation would retire in 2021, the first year of planning. Since it takes two to three years to plan, permit and construct new generation, for modeling this sensitivity, Rawhide Unit 1 was not allowed to retire before 2023. The Craig units were retired at their planned dates in 2025 and 2028 respectively, because Platte River cannot unilaterally retire them as a partial owner. The resulting least-cost portfolio with the social cost of carbon looks very similar to the zero coal portfolio but with an earlier transition to renewables. The portfolios are shown in Figure 9-9.

[12] Senate Bill 19-236 §40-3.2-106 (4)

Social cost of carbon sensitivity

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
CTs	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388
Craig	151	151	151	151	151	74	74	74												
Hydro	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91
RH1	278	278	278	278																
RICE					104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104
Solar	55	55	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	135
Solar (new)					100	200	200	300	300	400	400	400	400	400	400	400	400	400	400	400
Storage					100	200	200	200	300	300	300	300	300	350	350	400	450	500	600	600
Wind	231	231	231	231	231	231	231	231	225	285	285	285	285	285	285	285	285	285	285	285
Wind (new)					100	200	100	100	100	100	100	100	100	200	200	200	200	300	300	300

Portfolio 2: zero coal

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
CTs	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388
Craig	151	151	151	151	151	74	74	74												
Hydro	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91	91
RH1	278	278	278	278																
RICE					104	104	104	104	104	104	104	104	104	104	104	104	104	104	104	104
Solar	55	55	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	156	156
Solar (new)					100	200	200	300	300	300	300	300	300	300	400	400	400	400	400	400
Storage					100	200	200	200	300	300	300	300	300	350	400	400	450	450	450	450
Wind	231	231	231	231	231	231	231	231	225	285	285	285	285	285	285	285	285	285	285	285
Wind (new)					100	200	100	100	100	200	200	200	200	200	200	200	200	200	200	200

Figure 9-9 Expansion plan comparison; zero coal portfolio and the social cost of carbon sensitivity

Under the social cost of carbon sensitivity, Rawhide Unit 1 is replaced with 104 MW of RICE and 100 MW each of wind, solar and battery storage in 2025. As the Craig units are retired, additional storage and renewable resources fill in as needed until the portfolio reaches stability in 2030.

In terms of total generation cost and CO_2 reduction, the social cost of carbon sensitivity behaves like the zero coal portfolio except for the earlier retirement of the coal fleet, as shown in Figures 9-10 and 9-11.

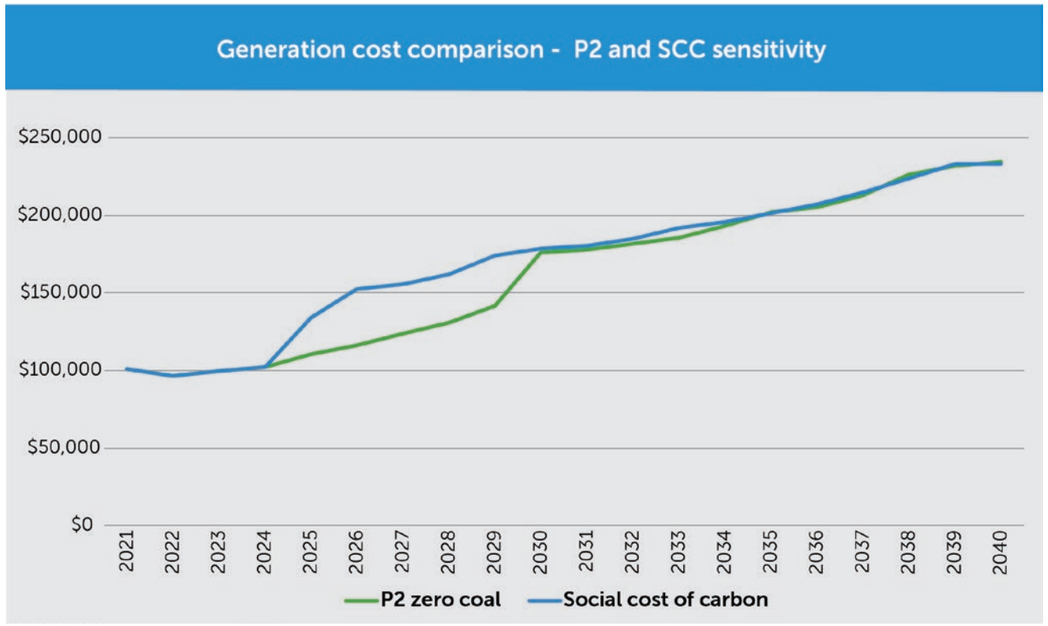


Figure 9-10

9.5.2 CO_2 cost sensitivity

As noted earlier, a CO_2 tax was included in all the portfolios. This CO_2 tax starts at about $4/ton in 2025 and escalates to around $9/ton in 2030 and $35/ton in 2040. Two sensitivities around the CO_2 tax were tested: a no carbon tax case and a tax equal to the social cost of carbon. The social cost of carbon starts in 2020 at $46/ton and escalates at 3% per year to reach approximately $98/ton in 2040. The results of CO_2 price sensitivity are shown in Figure 9-12.

The continuity portfolio with the highest level of coal generation shows the greatest risk exposure in terms CO_2 pricing, with an NPV cost reduction of about 10% in the no carbon tax case and a 90% increase in costs for the social cost of carbon case. The zero coal portfolio provides the lowest risk with a cost reduction of 3% in the no carbon tax case and a cost increase of about 50% in the social cost of carbon case. The integrated utilities portfolio risk profile falls between the continuity and zero coal portfolios with a cost decrease of 6% and an increase of 80%, respectively.

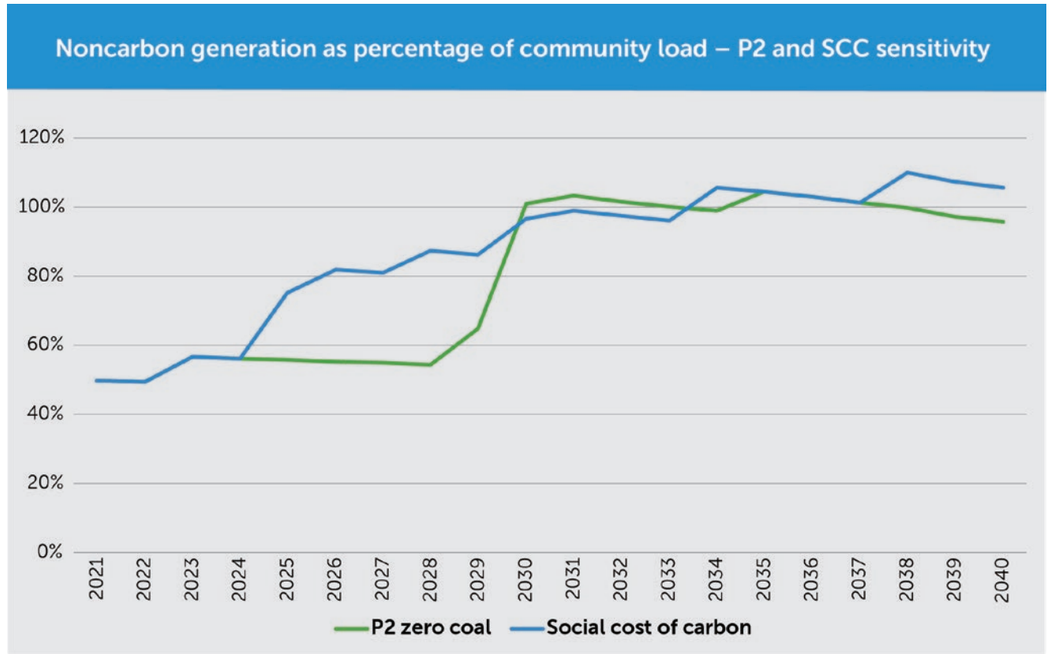


Figure 9-11

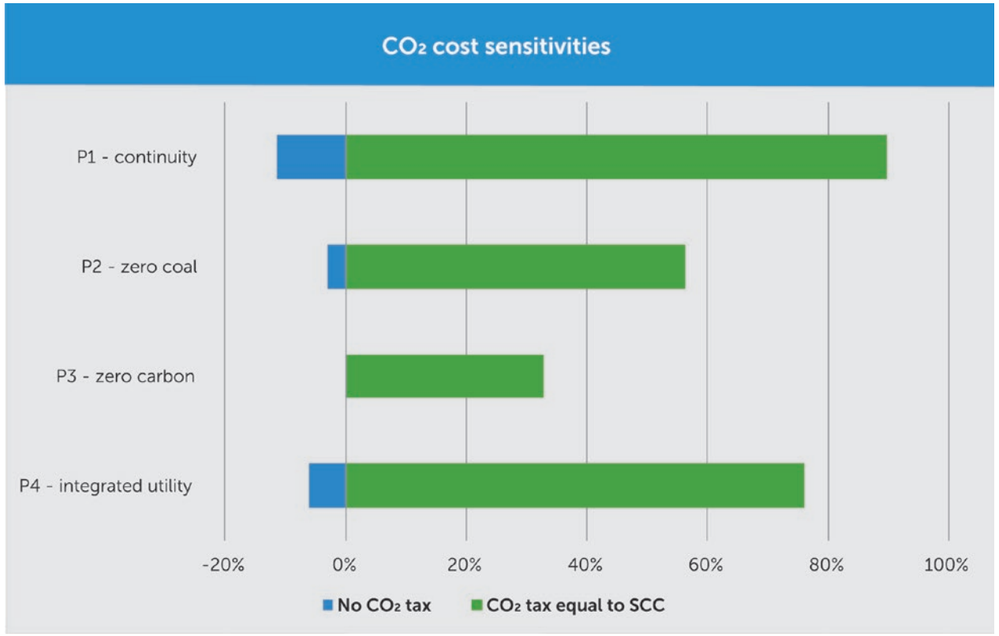


Figure 9-12

9.5.3 Gas price sensitivity

In addition to the base gas price forecast at CIG, two gas price sensitivities were considered: one representing high gas prices and another representing low gas prices. Gas price sensitivities, as well as the corresponding electricity market prices, were developed by Siemens. Base, high and low gas forecast price are provided in Figure 9-13.

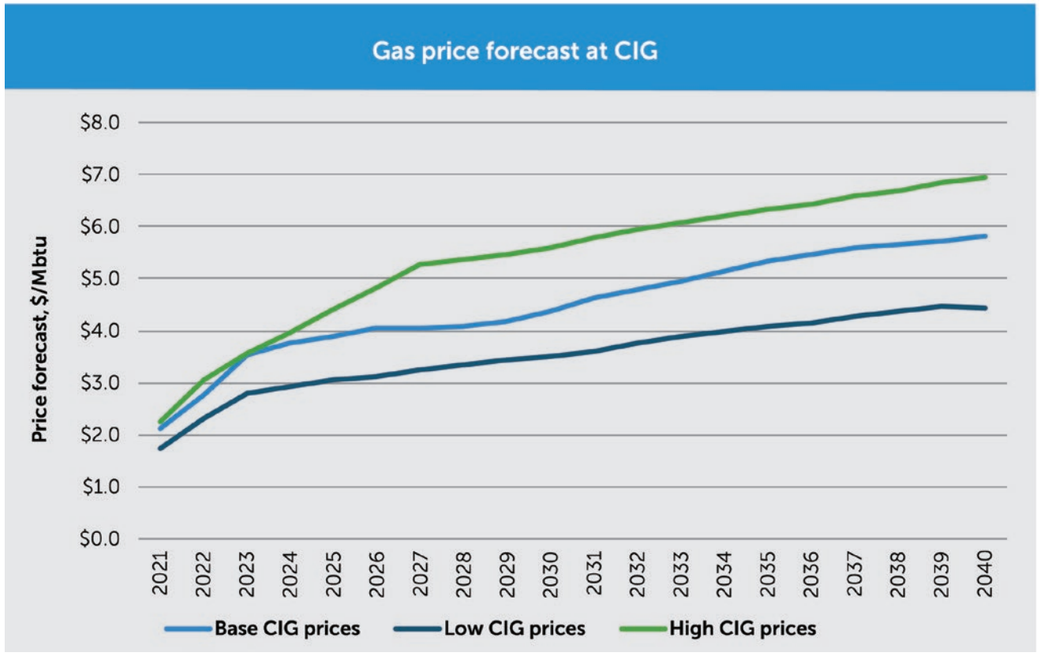


Figure 9-13

High gas prices typically lead to higher electricity market prices, which would enable increased opportunities for surplus sales from Platte River's coal and renewable generation fleet. Higher sales revenue generates greater margins, which lead to reduced costs for Platte River customers. Conversely, low gas prices suppress wholesale electricity prices, reducing surplus sales revenue and increasing customer costs. As shown in Figure 9-14, the continuity portfolio is the most sensitive to gas price changes, with a cost reduction of 3% in the high gas price case and a cost increase of 3% in the low gas price case. The zero coal portfolio is the least sensitive to gas price fluctuations, with a cost reduction of 1% and a cost increase of 1% for the high and low gas price sensitivities. The integrated utilities portfolio performs with less sensitivity than the continuity portfolio, with cost changes of about 2.5%. The zero carbon portfolio was not tested with gas price sensitivity because no gas would be used. Given these results, the continuity portfolio represents the largest cost risk associated with natural gas price variations.

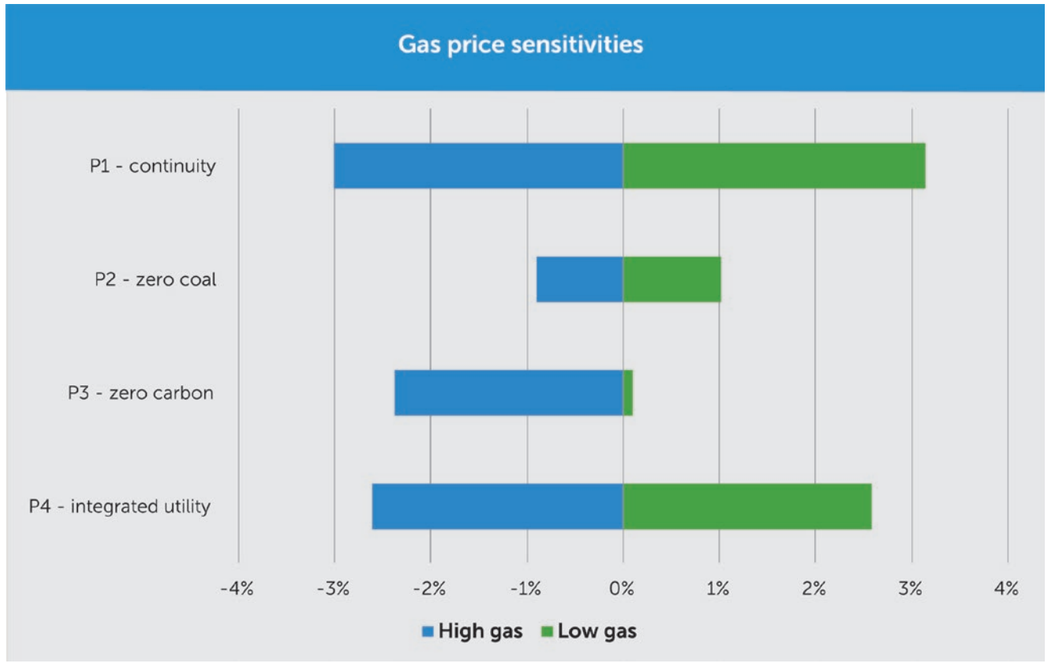
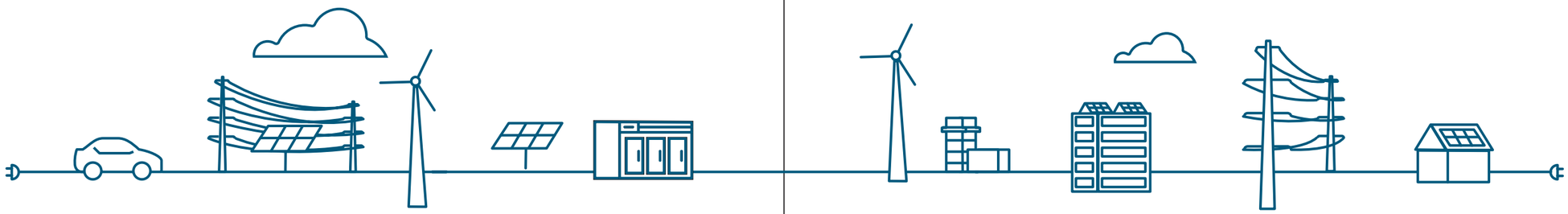


Figure 9-14

10 Recommendation



Portfolio 2: **zero coal**

Long term utility planning is a dynamic process, whereby the plans are updated regularly as technology evolves and new information becomes available. By developing four portfolios, this IRP illustrates four distinct futures out of an infinite number of possibilities.

The assumptions used in this IRP are based on the best available information at this time, but the industry is evolving quickly. To ensure timely decisions, Platte River will develop a generation supply plan before its next IRP, due in 2025, which will include updated assumptions and revised forecasts. Interim planning will allow Platte River to remain flexible, to take advantage of opportunities or respond to new developments.

To continue its journey toward a 100% noncarbon resource mix, **Platte River staff recommends the zero coal portfolio as the best option under the current assumptions.** With the announcement of the planned retirement of Rawhide Unit 1 by 2030, this portfolio represents a natural progression toward meeting the goals of the Resource Diversification Policy.

This portfolio significantly reduces emissions by relying extensively on renewable energy and using natural gas to maintain system reliability at a relatively low cost to the owner communities. Additionally, this portfolio meets the requirement of 80% CO_2 reduction from 2005 level and allows Platte River to file a voluntary CEP in compliance with state legislation (SB19-236 and HB19-1261). In addition to satisfying stakeholder desires for carbon emission reductions, the zero coal portfolio will ensure Platte River can meet future environmental requirements.

The recommended portfolio is a possible roadmap for the future and not a firm investment plan. Platte River staff is committed to modifying plans in line with the directions of the board and desires of the owner communities.

Staff will continue to refine this portfolio with new data and assumptions with a focus on evaluating battery storage and DERs to maintain reliability at a reasonable cost. With these refinements and improvements, Platte River will continue to advance toward a 100% noncarbon supply mix while maintaining the three pillars of safely providing reliable, environmentally responsible and financially sustainable energy and services.

11 Appendices

Appendix A. IRP checklist for WAPA[13]

Document section	Requirement	Included in this IRP	Section number
IRP portfolios	Does the IRP evaluate the full range of alternatives for new energy resources?	✓	7.9 – 7.14, 11.1, 11.3, 11.5
Ensuring system reliability	Does the IRP provide adequate and reliable service to the customer's electric consumer?	✓	8.1 – 8.4
Ensuring system reliability	Does the IRP take into account the necessary features for system operation?	✓	8.1 – 8.4
Existing DER programs and activities	Does the IRP take into account the ability to verify energy savings achieved through energy efficiency?	✓	6.7
Existing DER programs and activities	Does the IRP take into account the projected durability of such savings measure over time?	✓	6.7
IRP portfolios	Does the IRP treat demand and supply resources on a consistent and integrated basis	✓	6.8.2, 8.5
IRP portfolios	Does the IRP consider electrical energy resource needs? The IRP may, at the customer's option, consider water, natural gas, and other energy resource options.	✓	6.3
IRP assumptions – supply side	Does the IRP identify and compare resource options?	✓	7.9 – 7.14, 11.1
IRP portfolios	Does the IRP clearly demonstrate that decisions were based on a reasonable analysis of the options?	✓	9.3 - 9.7
IRP results and recommendations	Does the IRP include an action plan describing specific actions the customer will take to implement the IRP?	✓	1.2, 9.9
IRP portfolios	Does the IRP list the time period that the action plan covers?	✓	1.2, 9.9
IRP results and recommendations	Does the IRP include an action plan summary consisting of: Actions the customer expects to take in accomplishing the goals identified in the IRP? Milestones to evaluate accomplishment of those actions during implementation? Estimated energy and capacity benefits of each action planned?	✓	4.0
IRP results and recommendations	Does the IRP, to the extent practicable, minimize adverse environmental effects of new resource acquisitions and document these efforts?	✓	9.6
IRP results and recommendations	Does the IRP include a qualitative analysis of environmental effects in a summary format?	✓	9.6
Community engagement	Does the IRP provide ample opportunity for full public participation in preparing and developing the IRP?	✓	5
Community engagement	Does the IRP include a brief description of public involvement activities?	✓	5
	Does the IRP document that each member based association (MBA) member approved the IRP, confirming that all requirements have been met?	NA	
	Does the IRP contain the signature of each MBA member's responsible official, or document passage of an approval resolution by the appropriate governing body?	NA	
Load forecast	Does the IRP contain a statement that the customer conducted load forecasting, including specific data?	✓	6.1 – 6.2
IRP results and recommendations	Does the IRP contain a brief description of measurement strategies for identified options to determine whether the IRP's objectives are being met?	✓	10
IRP portfolios	Does the IRP identify a baseline from which the customer will measure the benefits of IRP implementation?	✓	8.5
	Does the IRP specify the responsibilities and participation levels of individual members of the MBA and the MBA?	NA	

[13] This check list is available at https://www.wapa.gov/EnergyServices/IRP/Pages/review-checklist.aspx

Appendix B: IRP studies

Key findings of the nine studies conducted by Platte River's outside consultants and advisors as part of this IRP are discussed blow. Where appropriate, the full studies are available on the IRP microsite.

1. Generation technology review

Consultant: Pace/Siemens Inc.

The generation technology review (GTR) is a comprehensive study of resources that Platte River may evaluate in more detail during the 2020 integrated resource planning (IRP) process. The GTR helps to identify the most viable resource options to help meet the energy goals of the owner communities and their communities.

Key findings:

- Existing generation resources continue to provide reliable supplies until their respective retirement dates
- Should consider solar, wind, battery storage, distributed resources, energy efficiency, demand response and gas-fired fossil fuel generation to meet future energy needs

2. Regional economic impacts

Consultant: Colorado State University

The economic impact study estimates the impacts of a range of potential electricity price changes due to changes in the generation portfolio. Economic impacts were estimated for each of the four communities served by Platte River—The Town of Estes Park, and the Cities of Fort Collins, Longmont and Loveland. The impacts on both residential and commercial users were estimated as well. Multiple metrics, including changes in employment, household income, and local economic activity (called domestic supply), are used to measure the economic impacts.

Key findings:

- Rate increases will have
  - Higher impact on low income households
  - Potential negative impact on businesses through higher production costs

3. Energy storage technology assessment

Consultant: HDR Inc.

This report provides technology characteristics and an estimated cost comparison of several specific types of Energy Storage Systems that are suitable for use on Platte River's system. Characteristics of pumped hydropower energy storage systems (PHES), battery energy storage systems (BESS), and compressed air energy storage are discussed in this report. Life cycle cost estimates for PHES and BESS technologies are analyzed over a 30-year life cycle cost basis considering operations and maintenance costs, major maintenance, augmentation, purchased power, and capital recovery costs. Using these results technologies are compared on levelized costs.

Key findings:

- Lithium-ion batteries and pumped hydro storage are commercially proven technologies
- Lithium-ion batteries have the lowest life cycle cost estimate for four-hour storage requirements
- Pumped hydro storage has the lowest life cycle cost for 10-hour storage
- May take 8-10 years to build
- Environmental impacts/permitting challenges

4. Coal cycling

Consultant: Burns & McDonnell Inc.

This study examines the operational and economic impacts on the Rawhide coal unit as cycling increases to follow intermittent renewable energy generation. As more renewable resources are added to Platte River's portfolio and in the region, baseload coal units will need to cycle more than they have traditionally done in the past.

Key findings:

- Rawhide coal unit will have more starts per year to follow intermittent renewable generation
- Fixed operations and maintenance cost will increase

5. Thermal generation alternatives

Consultant: HDR Inc.

This report evaluates thermal generation options to support and allow for the integration of renewable generation. The purpose of this study is to characterize potential natural gas fired generation resources selected by the Platte River evaluation team in support of the IRP process. The information provided in this study includes generation performance estimates, emissions data, capital cost estimates, operations and maintenance cost estimates, and inputs to the Aurora electric market model for each of the potential generation options identified.

Key findings:

- Small gas turbines and reciprocating engines are viable backup thermal resources for Platte River to complement intermittent renewable resources
- Reciprocating engines can be installed in smaller increments
- Small gas turbines have lower capital cost

6. Resource adequacy review

Consultant: Burns & McDonnell Inc.

This report provides a review of reliability and planning regulations related to increased wind and solar penetration, reserve requirement metrics, and methods to determine adequate reserve margins. The goal for this review is gain a better understanding of the planning criteria needed to ensure reliability when relying on intermittent renewable generation and energy storage systems.

There are three reliability related metrics that are reviewed: a review of Effective Load Carrying Capability, a review of Platte River's Loss of Load Probability and an assessment of regulatory and policy requirements for today and in the future.

Key findings:

- Continue to use 15% planning reserve margin as recommended by the North American Electric Reliability Corporation
- Use declining curves for capacity contribution from wind and solar resources for reliability purposes

7. Market analysis

Consultant: PACE/Siemens Inc.

This report provides price forecasts for gas, power, renewables and emissions that are used as inputs to the Aurora model.

Key findings:

- Gas prices will stay depressed through 2023, before increasing due to increasing exports and consumption in the power sector
- A carbon tax will be levied within the next five years
- In the short run, solar and wind prices will increase due to tax incentive expiration in 2023
- Over the long run, solar and battery prices will continue to decline due to technological improvements

8. DER potential

Consultant: HDR Inc.

The purpose of this report is to evaluate DERs, including energy efficiency, demand response (including distributed energy storage and EVs) and distributed solar and to forecast how much DERs are cost-effective and achievable.

Key findings:

- May be able to increase annual energy efficiency results
- Demand response has potential to reduce peak hour electric demand
- Distributed solar is anticipated to grow

9. Life cycle carbon impact

Consultant: Colorado State University

This report provides estimates the lifetime carbon emissions of generation resources, including carbon emissions during manufacturing, construction and operation.

Key findings:

- Coal is the biggest source of CO_2 operating emissions with emission rate at 1150 kg/MWh. For coal fired plants, CO_2 emissions related to coal mining and transportation are approximately 10% of the stack emissions.
- Natural gas-fired generation operating emission rate (including extraction, fugitive and transport losses) is between 60% and 70% of the coal operating emission rates. Stack-only CO_2 emissions from new natural gas-fired generation are approximately 50% of the stack emissions of coal-fired generation.
- CO_2 emissions related to manufacturing, transportation, construction, commissioning and decommissioning are relatively insignificant as compared to operating emissions for all types of thermal generation.
- Lifetime average CO_2 emissions from solar, wind and battery storage are negligible while hydro power emission rate is 25 kg/MWh, which is small compared to thermal resources.

Appendix C: DER programs

Demand response measures

Residential			
HVAC programmable communicating thermostat (PCTs)	All residential	3	24
HVAC DLC	All residential	3	24
Water heater DLC	All residential	3	48
Battery and plug-in hybrid vehicles DLC - charging interruption during peak hours	All residential	4	260
BESS (5 kW) automated demand response	Single family	4	260
BESS (5-10 kW) automated demand response	Multi-family	4	260
Commercial / industrial			
HVAC automated demand response	Commercial / industrial	3	24
HVAC DLC and PCTs	Commercial / industrial	3	24
50 kW BESS automated demand response	Commercial / industrial	2	260
150 kW BESS automated demand response	Commercial / industrial	2	260
Industrial process - automated demand response	Industrial	3	48
Industrial process - manual demand response	Industrial	3	48
Lighting - luminaire, zonal and standard control options	Commercial / industrial	3	48
Refrigerated warehouse - automated demand response	Industrial	3	48
Other			
Voltage reduction	System	4	36

Residential energy efficiency measures

Heating	
Smart thermostat installation - electric heating*	All residential
Smart thermostat installation - gas heating*	All residential
Programmable thermostat installation - heating	All residential
Weatherization: air sealing	All residential
Weatherization: insulation	All residential
High efficiency windows	All residential
Installation of ENERGY STAR® storm windows/doors	All residential
Install heat recovery ventilation	All residential
Cooling	
Central air conditioner upgrade	All residential
Smart thermostat installation - cooling*	All residential
High efficiency air handler/rooftop units	Multi-family
Ventilation	
Electrically commutated furnace blower motor	All residential
Water Heating	
Heat-pump electric storage water heater	All residential
Lighting	
LED upgrade (interior)	All residential
LED upgrade (exterior)	Single family
Refrigeration	
ENERGY STAR® freezer	All residential
ENERGY STAR® refrigerator	All residential
Refrigerator recycling	All residential
Miscellaneous	
ENERGY STAR® pool pumps	All residential
ENERGY STAR® dishwasher	All residential
ENERGY STAR® clothes washer	All residential
ENERGY STAR® clothes dryer	All residential
ENERGY STAR® electronics (advanced power strip)	All residential
Faucet aerators	All residential
Low flow shower heads	All residential

* A smart thermostat is one physical device but impacts both heating and cooling. Therefore, the smart thermostat measures are broken down by end-use and customer heating type. During total resource cost test, the measures were appropriately combined to evaluate the economic viability.

Commercial & industrial energy efficiency measures

Heating	
Smart thermostat installation - heating*	All commercial categories
Cooling	
Air-cooled chiller upgrade	All commercial categories
Water-cooled chiller upgrade	Healthcare, industrial, and office categories
Evaporative pre-cooling installation on air-cooled condenser	Retail, education, healthcare, industrial, office and utility
High efficiency air handler/rooftop units	All commercial categories
Advanced RTU controller (ARC) retrofit	All commercial categories
Smart thermostat installation - cooling*	All commercial categories
Ventilation	
Electrically commutated motor-variable air volume	All commercial categories
NEMA super premium motors	Education, healthcare, industrial, office, utility
Lighting	
LED screw-in upgrade from CFL (interior)	All commercial & Industrial categories
LED linear upgrade from T8/T12 (interior)	All commercial & Industrial categories
LED high-bay fixtures (interior)	Industrial
LED upgrade (exterior)	All commercial categories
LED screw-in upgrade (exterior)	Industrial
LED area lighting upgrade (exterior)	Industrial
LED linear lighting upgrade (exterior)	Industrial
Smart lighting controllers / occupancy sensors	All commercial categories
Smart lighting controllers / daylight sensors	All commercial categories
Cooking	
Electric combination ovens	Food sales, food service and healthcare categories
Electric exhaust hood	Food sales, food service and healthcare categories
Refrigeration	
Refrigerator floating-head pressure controls	Food sales and food service categories
Refrigerator/freezer gaskets	Food sales and food service categories
Office equipment and computing	
Advanced power strips	All commercial & industrial categories
Miscellaneous	
Energy assessment retro-commissioning	All commercial & industrial categories
Energy management system with data analysis	All commercial & industrial categories

*A smart thermostat is one physical device but impacts both heating and cooling. Therefore, the smart thermostat measures are broken down by end-use and customer heating type. During total resource cost test, the measures were appropriately combined to evaluate the economic viability.

Appendix D: Aurora model

Aurora modeling software is an economic optimization tool. This model is used by Platte River for long-term capacity expansion planning, budget modeling and transaction analysis. The model economically dispatches each generation unit while respecting its operational constraints to meet hourly chronological load. For future years, when demand exceeds the existing resources, it selects the most economical next candidate unit (thermal, renewable or battery storage) to reliably meet future energy and capacity needs. While simulating the operation of Platte River system, the model allows buying and selling from an outside market to lower costs.

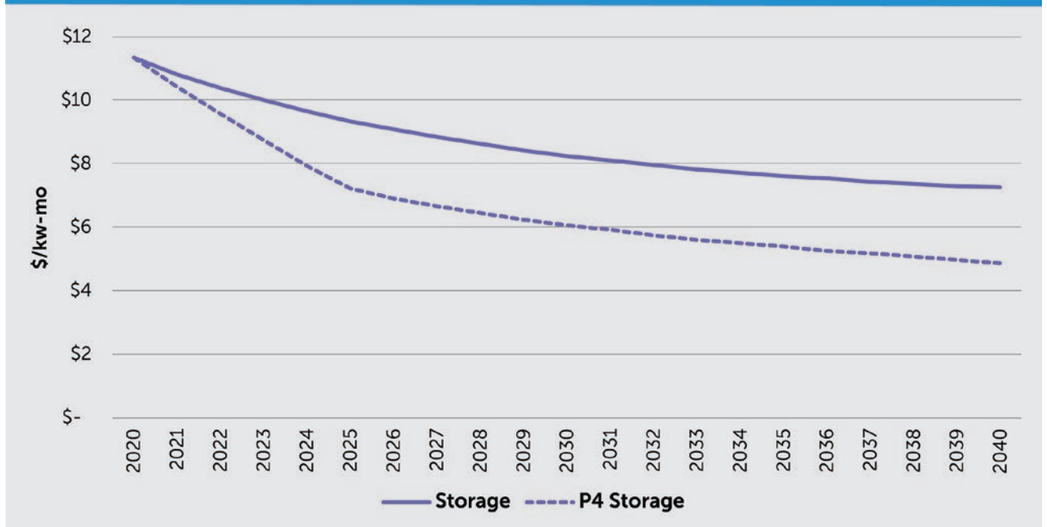
For capacity expansion planning, the model chooses from a menu of available candidate units including thermal units, noncarbon resources and storage. The expansion plan will weigh the economics of unit additions while ensuring enough firm capacity is built to maintain a planning reserve margin. The software can also economically retire units. An initial portfolio of units is chosen in the first run and then subsequent runs test resource additions and removals and modify the portfolio to reduce costs. When the software can no longer find a solution that is cheaper than the current candidate, it stops the iterative process. The final portfolio is reviewed and may be adjusted slightly to ensure it reflects a realistic plan. For example, the least cost plan may add storage a year after adding a renewable energy unit. This would be corrected to add both simultaneously even if the cost was slightly higher.

Expansion plans with high penetrations of renewable energy and storage are difficult to optimize in an iterative manner as modeled in the Aurora software. The value of renewable energy and storage are not strictly independent so testing their economics independently may not extract their full value. For these portfolios, additional runs were made using the least-cost plans developed by Aurora. Resource additions were moved earlier and later and the magnitudes where shifted up and down as well. The final portfolios reflect the least-cost solution resulting from both the Aurora optimization algorithm and expert judgment.

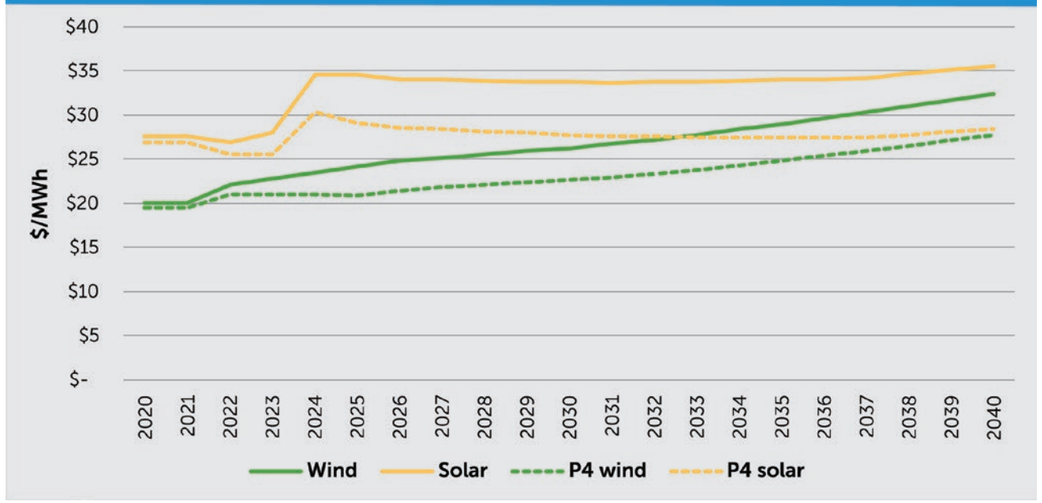
Appendix E: P4 assumptions

Lower bounds from the price forecasts were used to generate the price assumptions in P4. The cost of batteries is approximately 33% lower in 2040, while wind and solar are 14% and 20% lower, respectively. Of these three technologies, batteries have the largest opportunity for cost reductions due to technological and manufacturing advancements. The solar industry is more mature than the battery industry but still has opportunities to become more efficient and, in turn, reduce costs. The wind industry is believed to be mature with highly optimized designs and manufacturing and thus has few opportunities for additional efficiencies. As a result, the cost curve for batteries is declining over time, the solar costs are holding flat, and wind costs are rising due to inflation.

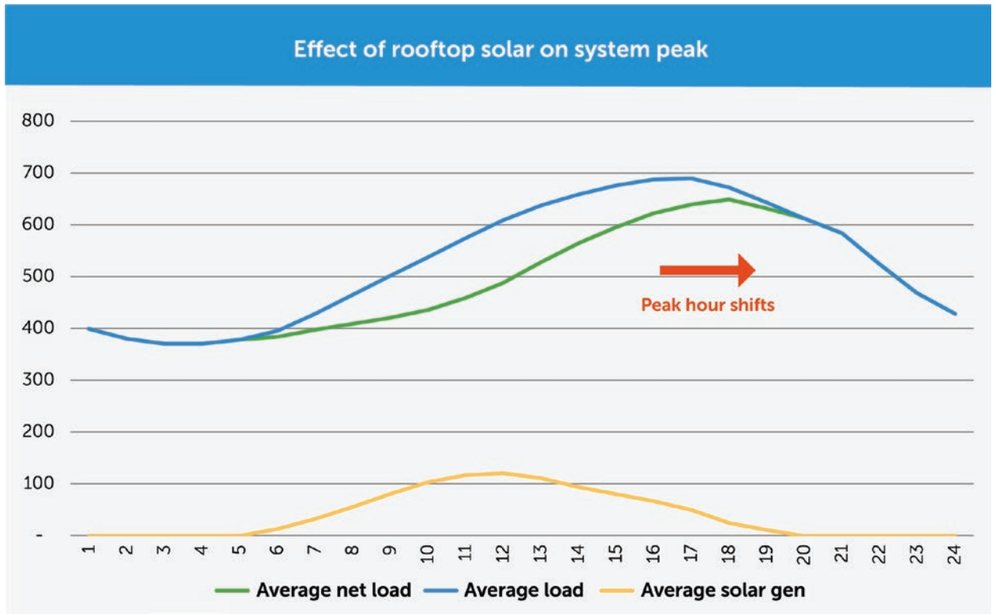
Energy storage price forecast for P4



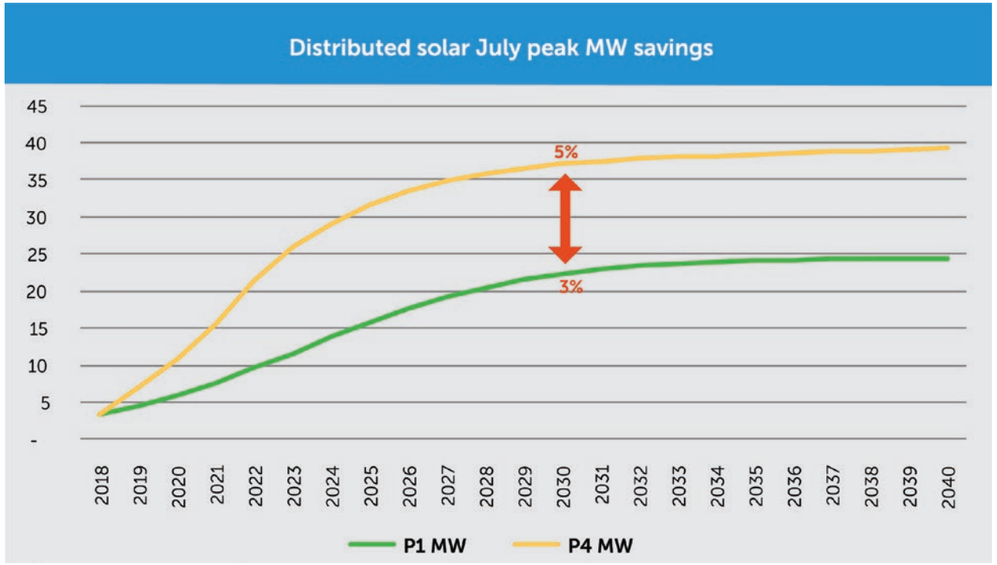
Solar and wind price forecast for P4



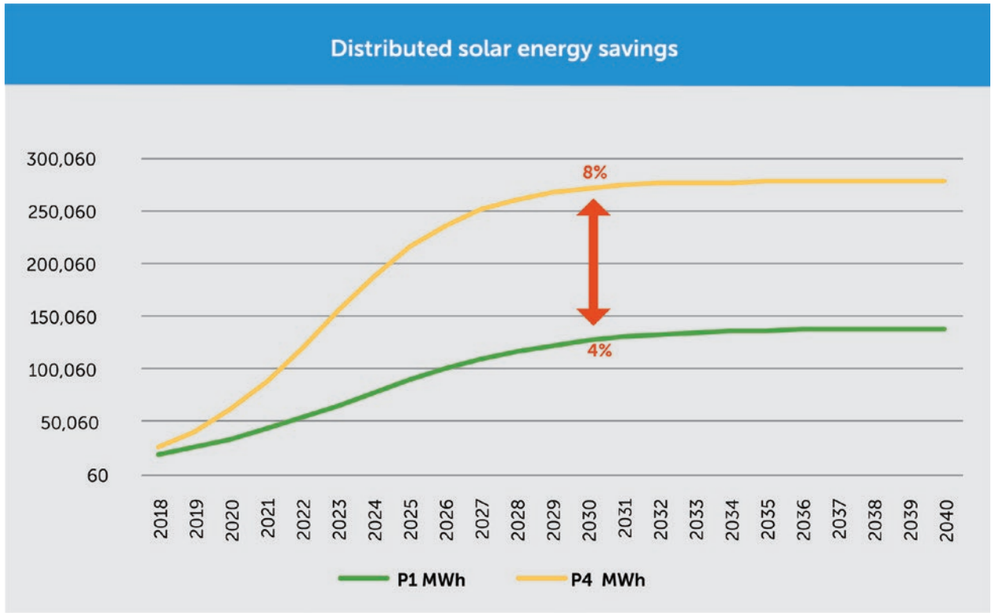
The lower cost assumptions in P4 lead to increased rooftop solar penetration, in fact, double the level of penetration in P1-P3. Doubling the number of rooftop solar panels doubles the amount of energy produced by them. Accordingly, the impact on Platte River energy is also doubled. The impact on Platte River peak demand is not doubled due to shifting of the peak hour with more distributed solar as shown in the following chart.



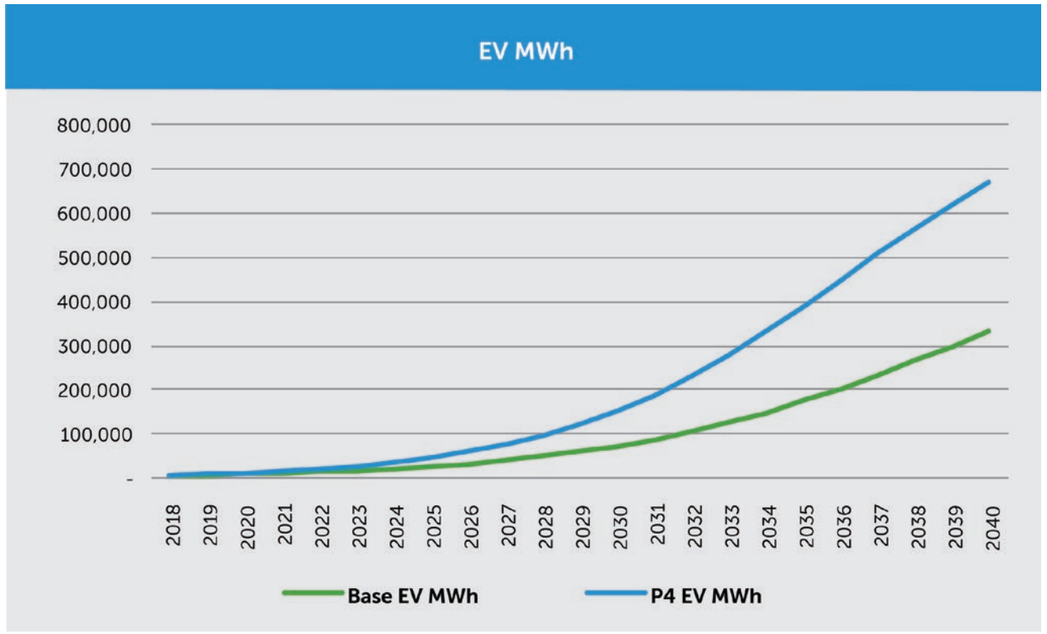
In the base assumption, distributed solar reduced peak demand in 2030 by around 3%, and after double distributed solar in P4 the peak demand was reduced by about 5% in 2030 as shown in the following chart.



Doubling of the solar generation also doubles the total energy reduction as shown in the following chart.



Similarly, EV penetration for P4 was double that of P1-P3. Total increase in energy demand due to EVs in the base case and for P4 is shown in the following chart.



Platte River Power Authority

Estes Park • Fort Collins • Longmont • Loveland

www.PRPA.org

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-92:
Platte River 2024 IRP

Platte River Power Authority

Estes Park • Fort Collins • Longmont • Loveland

2024

Integrated Resource Plan

Platte River
Power Authority

Estes Park • Fort Collins • Longmont • Loveland

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Glossary

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

LOLE ..... Loss of Load Expectation

LOLH ..... Loss of Load Hours

MISO ..... Midcontinent Independent System Operator

MW ..... Megawatt

MWh ..... Megawatt-hours

NEM ..... Net energy metering

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

NREL ..... National Renewable Energy Laboratory

ODTY ..... One Day in Ten Years

PPA ..... Power purchase agreement

PRM ..... Planning reserve margin

RDP ..... Resource Diversification Policy

RFP ..... Request for proposals

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

RTO West ..... Regional Transmission Organization West

SPP ..... Southwest Power Pool

TOU ..... Time of use

VPP ..... Virtual power plant

WAPA ..... Western Area Power Administration

WECC ..... Western Electricity Coordination Council

WEIS ..... Western Energy Imbalance Service market

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01 Executive summary

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

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

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

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

Outreach and engagement

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

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

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

Portfolios

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

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

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

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

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

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

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

Conclusion

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

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

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

02 Introduction

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

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

The report is organized as follows:

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

Public power utilities

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

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

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

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

2.1 Platte River overview

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

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

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

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

2.1.1 Foundational pillars

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

Reliability

Providing a highly reliable supply of power to our owner communities

Environmental responsibility

Achieving noncarbon energy goals and protecting our natural resources

Financial sustainability

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

2.1.2 Vision, mission and values

Our vision

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

Our mission

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

Our values

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

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

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

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

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

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

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

Environmental leadership

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

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

2.2 Resource Diversification Policy

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

Purpose

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

Policy

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

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

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

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

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

Figure 1. *Resource Diversification Policy*

03 IRP process overview

3.1 What is an IRP?

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

Key components of an IRP include:

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

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

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

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

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

3.2 Why do an IRP now?

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

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

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

3.2.1 IRP timeline

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

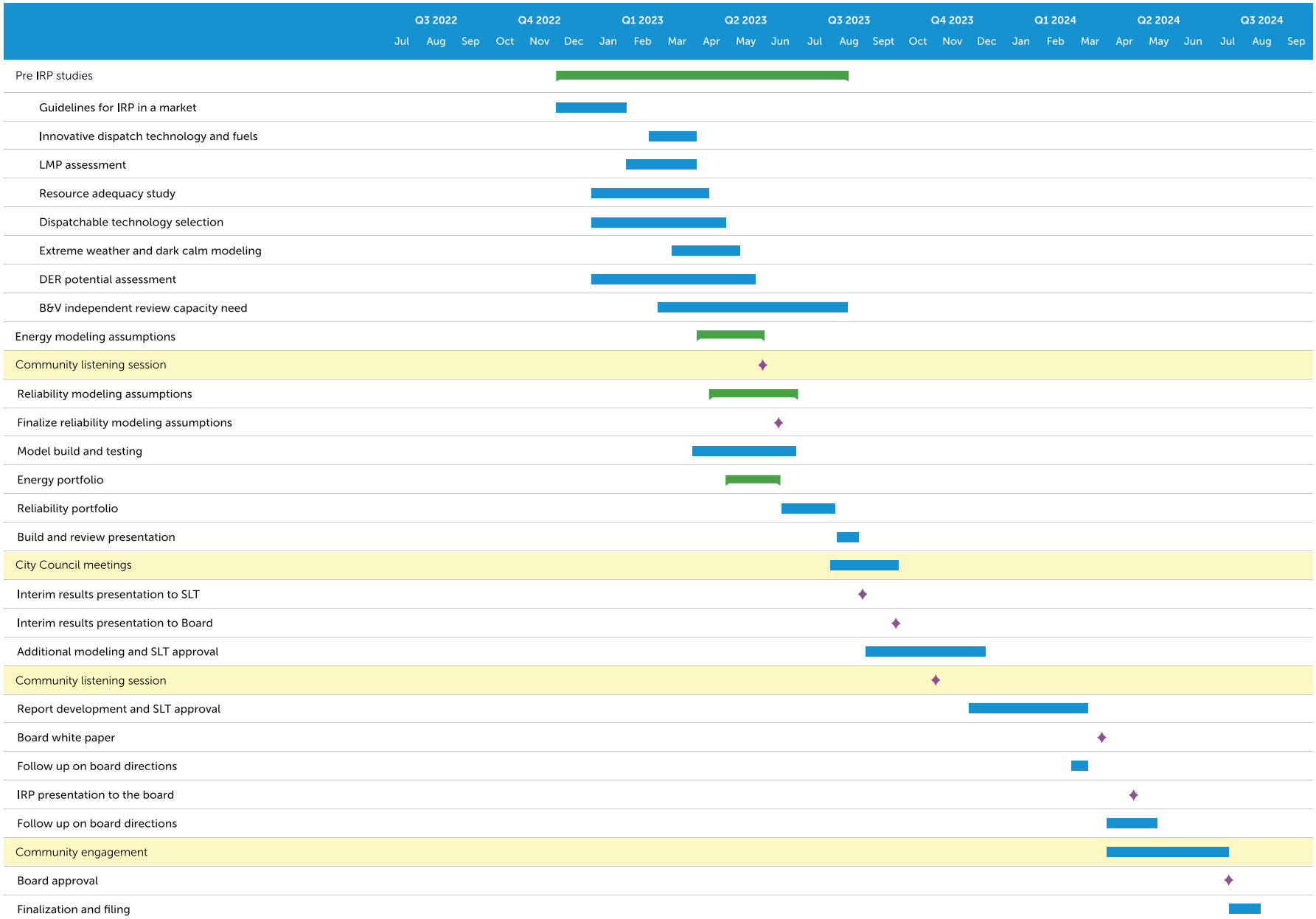


Figure 2. *Timeline of 2024 Integrated Resource Plan activities and milestones*

3.3 Progress since the last IRP

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

2020

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

2021

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

2022

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

2023

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

3.4 External developments since the 2020 IRP

3.4.1 Pandemic

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

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

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

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

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

3.4.2 Supply chain issues

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

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

3.4.3 Renewable resource pricing

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

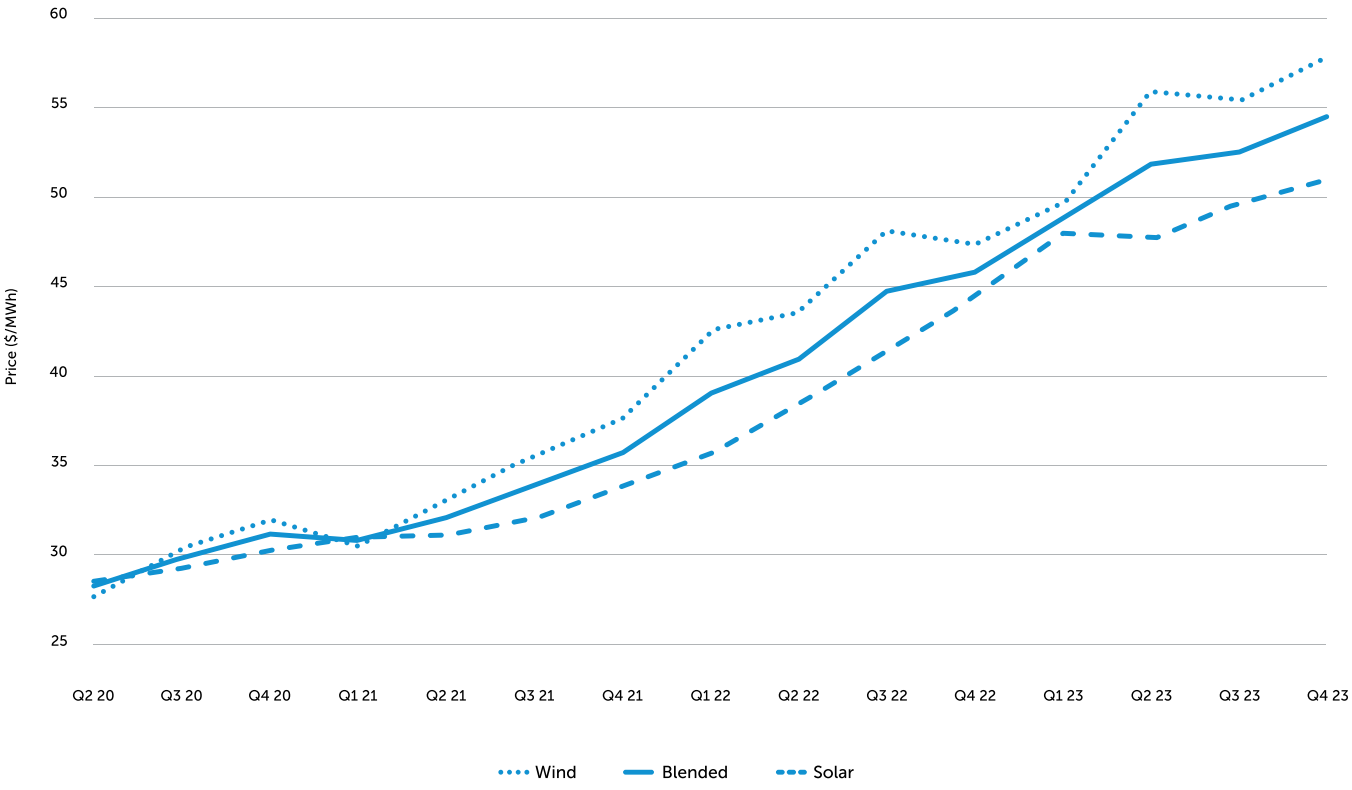


Figure 3. *PPA prices in the U.S. between 2020 and 2023*

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

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

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

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

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

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

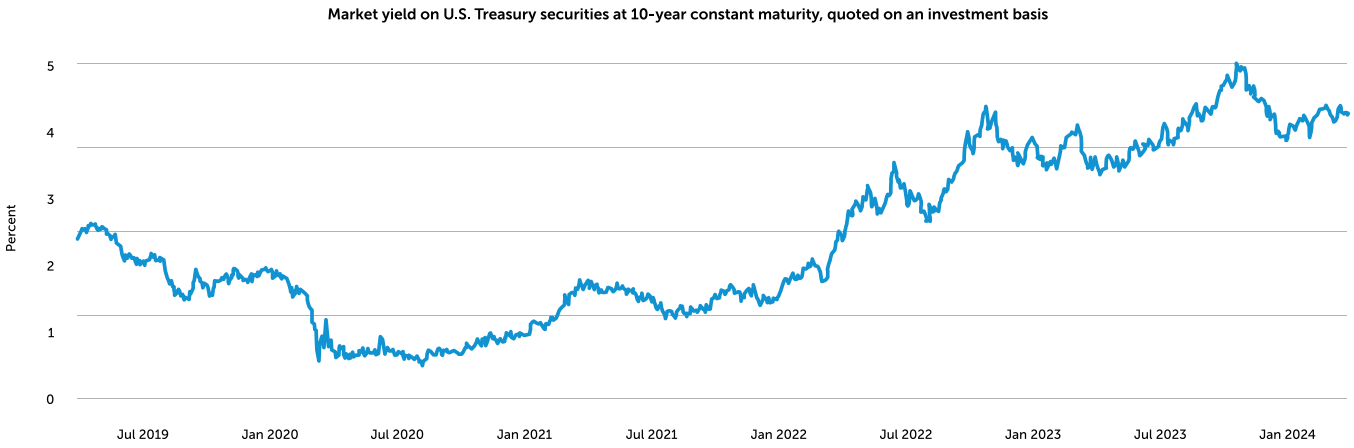


Figure 4. *Market yield on U.S. Treasury securities at 10-year constant maturity, quoted on an investment basis*

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

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

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

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

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

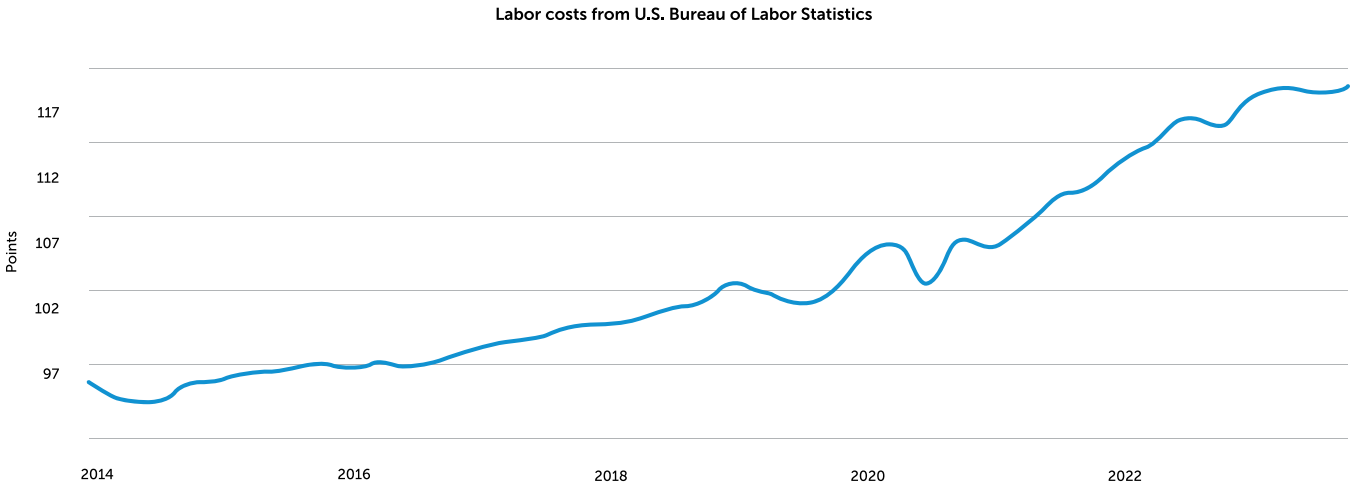


Figure 5. *Labor costs from U.S. Bureau of Labor Statistics*

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

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

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

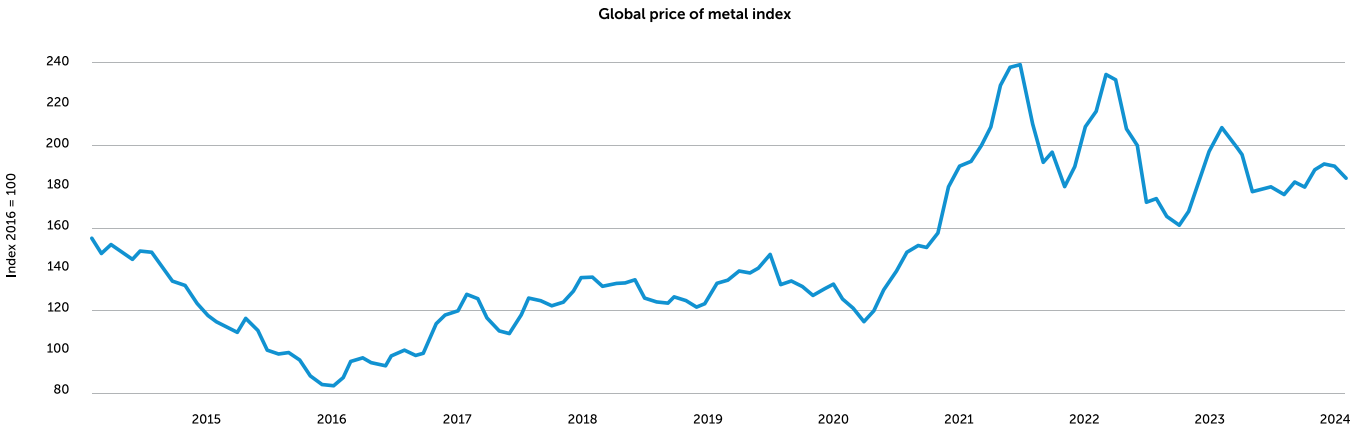


Figure 6. *Global price of metal index*

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

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

3.5 Resource planning refresh in 2022

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

3.5.1 Acceleration of renewable integration

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

3.5.2 Extreme weather modeling

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

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

3.5.3 Expanded DER impact

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

3.5.4 Renewable supply chain impact

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

3.6 Regulatory environment

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

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

3.6.1 Colorado policy review

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

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

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

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

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

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

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

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

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

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

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

3.6.2 Federal policy overview

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

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

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

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

3.7 Stakeholder engagement process

3.7.1 Outreach strategy

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

3.7.1.1 Community meetings

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

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

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

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

Timeline
June
July
Aug
Sept
Oct
Nov
Dec
Jan
Feb
Mar
April
May
June
Community engagement
Resource planning
• Pre-IRP studies
• Load forecasting
• Other inputs, assumptions

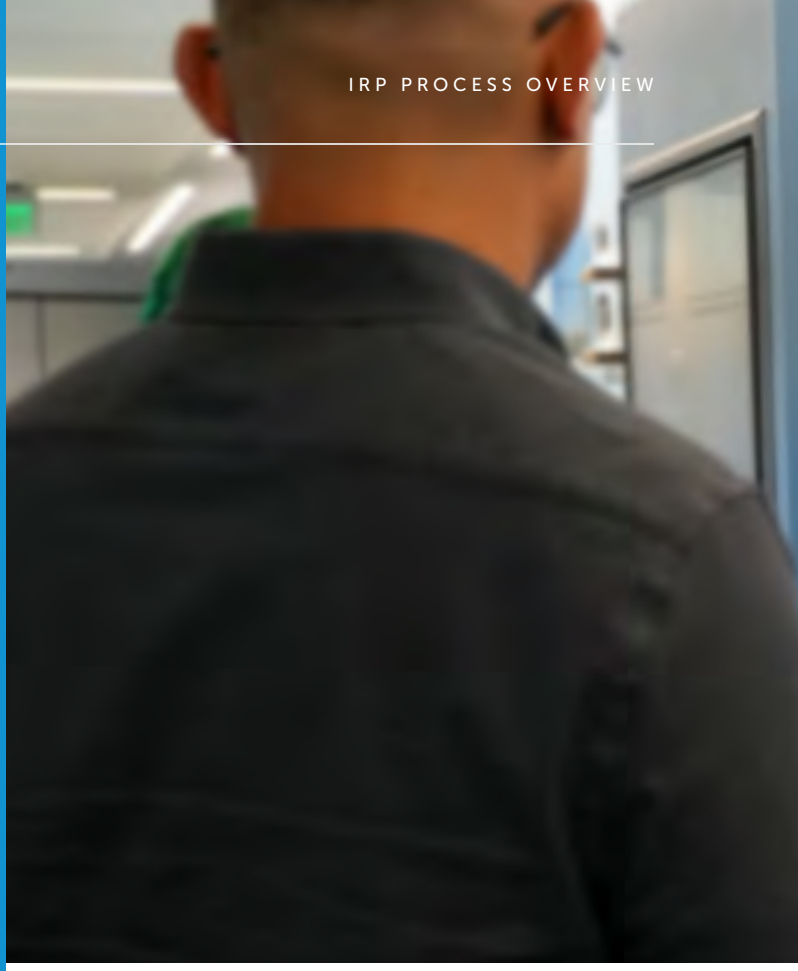
Each presentation gave the audience an opportunity to ask questions. The Platte River team continues to receive questions via email, social media and in-person. To date, we have logged and answered over 150 questions.

Presentations per owner community:

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

Presentations per community group type:

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



3.7.1.2 Business community engagement

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

3.7.1.3 Consulting with industry experts

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

3.7.2 Campaigns and resources

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

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

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

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

3.7.2.1 Microsite

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

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

3.7.2.2 Dedicated email

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

3.7.3 Results

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

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

04

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

4.1 Key variables and strategic considerations

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

4.1.1 Load forecast

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

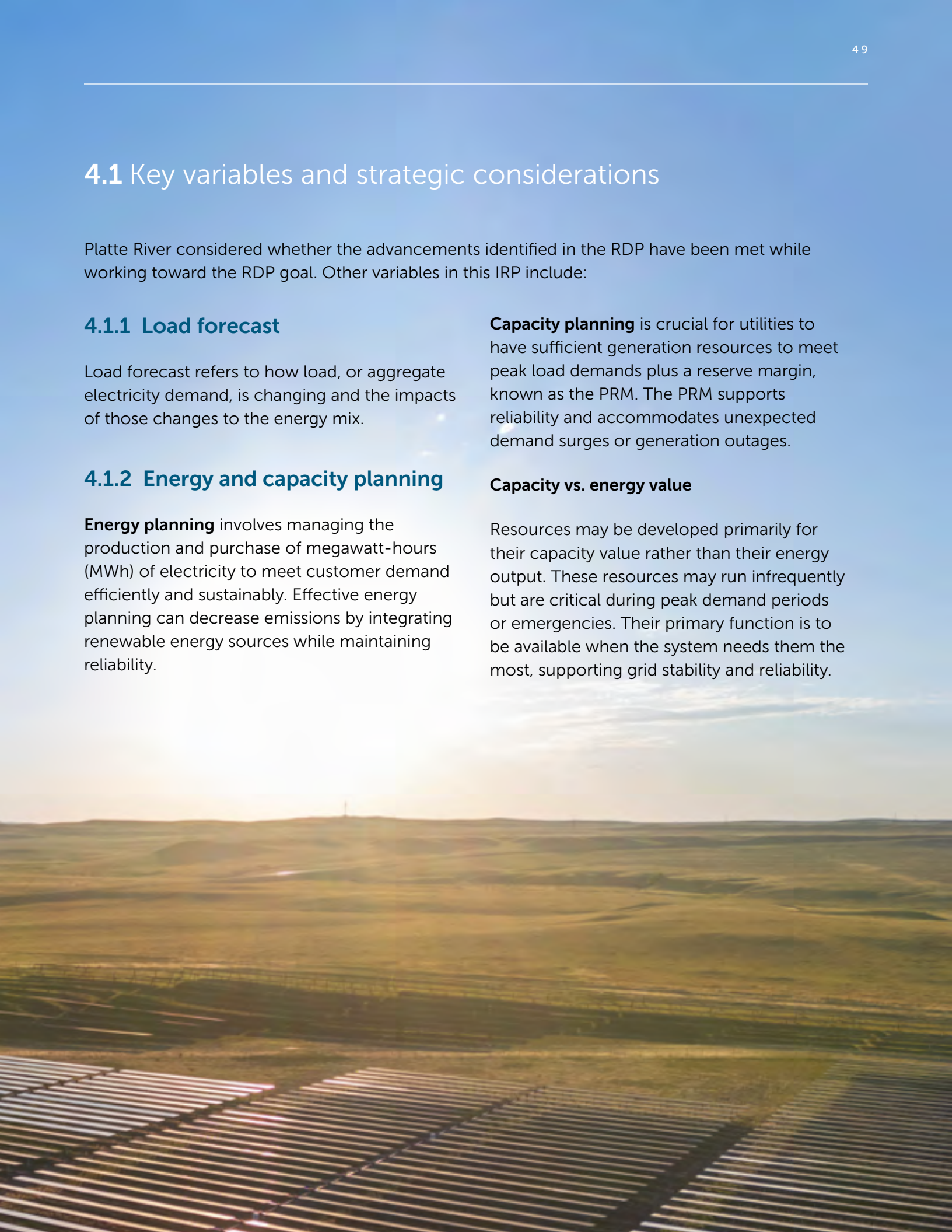
4.1.2 Energy and capacity planning

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

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

Capacity vs. energy value

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



4.1.3 Customer programs

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

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

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

4.1.4 Emerging technologies

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

4.1.5 Power markets

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

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

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

4.1.6 Resource adequacy

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

4.1.7 Transmission and distribution infrastructure

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

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

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

4.1.8 DER adoption and integration

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

4.2 Navigating challenges and maintaining the foundational pillars

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

4.2.1 Reliability – dispatchable capacity

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

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

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

4.2.2 Environmental responsibility – cost of carbon

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

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

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

4.2.3 Financial sustainability – rates and affordability

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

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

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

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

- Generate adequate earnings margins and cash flows

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

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

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

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

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

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

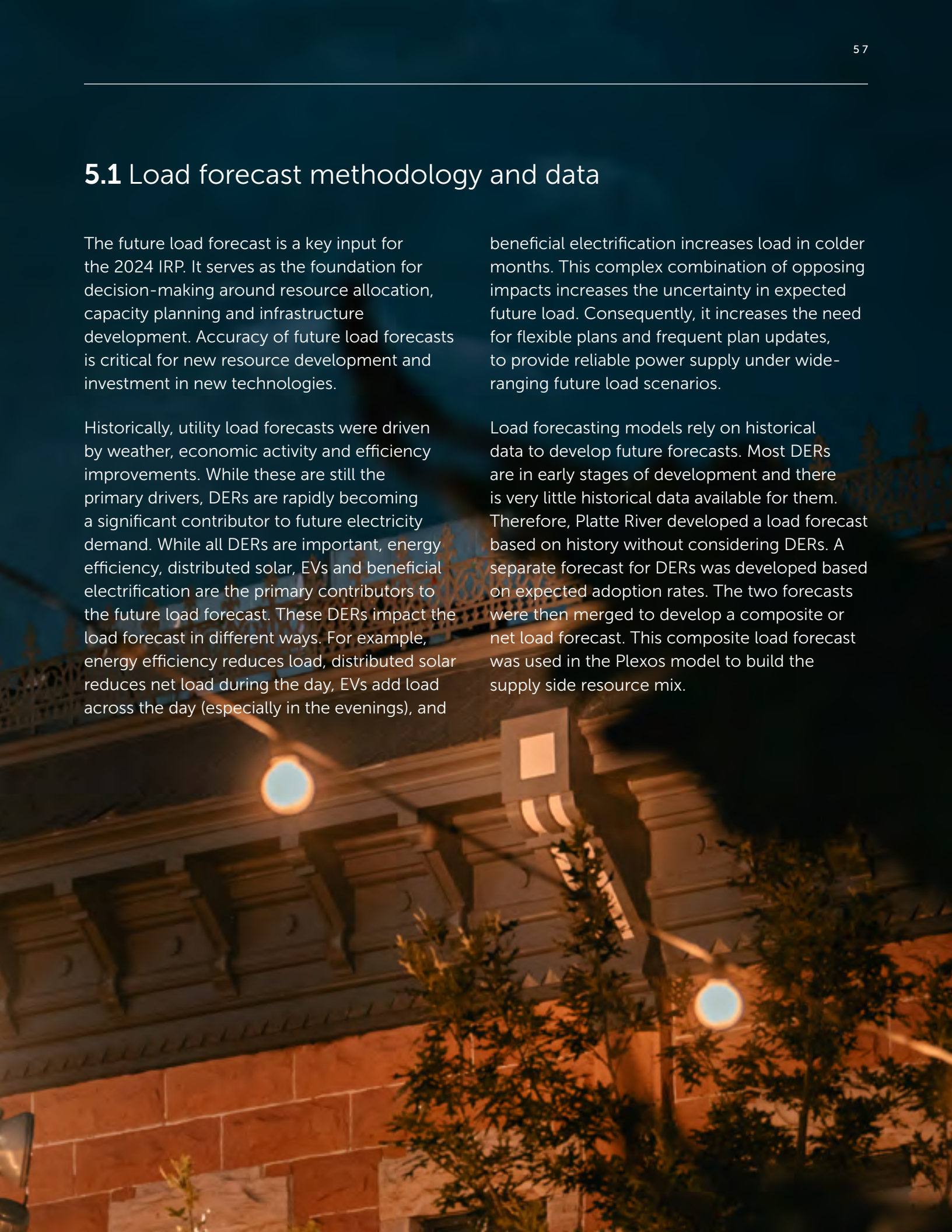
05 Electricity demand

5.1 Load forecast methodology and data

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

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

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



5.2 Load forecast without DER

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

5.2.1 Methodology

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

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

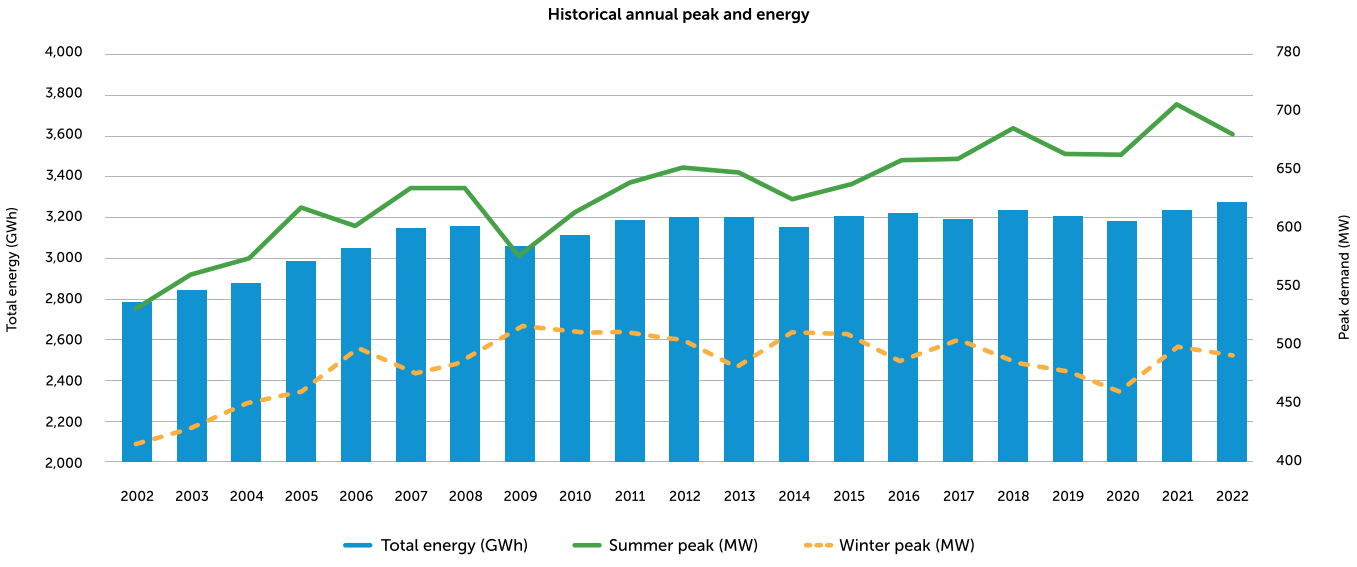


Figure 7. *Historical annual peak and energy*

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

5.2.2 Forecast drivers

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

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

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

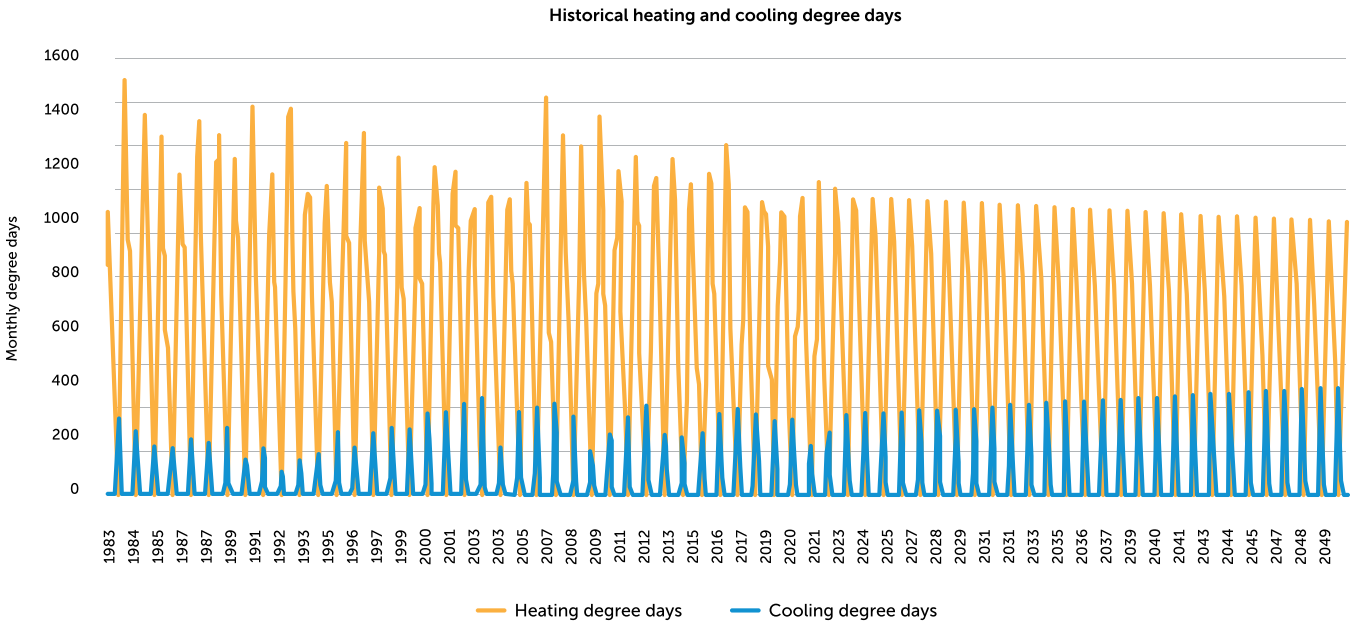


Figure 8. *Historical heating and cooling degree days*

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

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

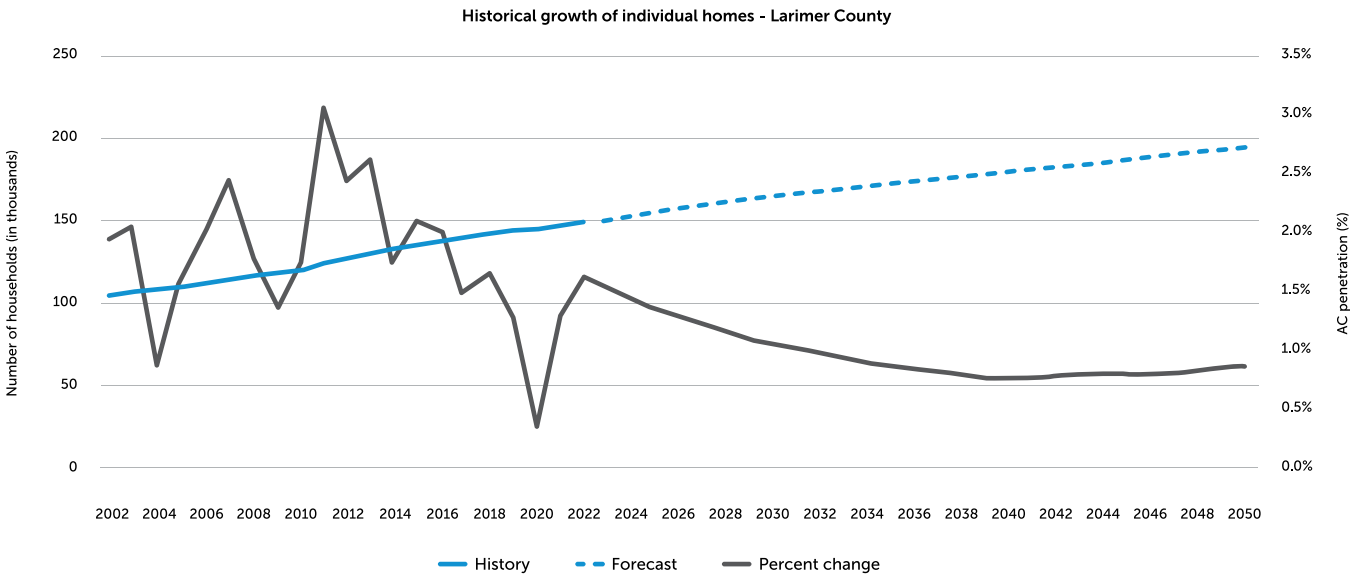


Figure 9. *Historical growth of individual homes*

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

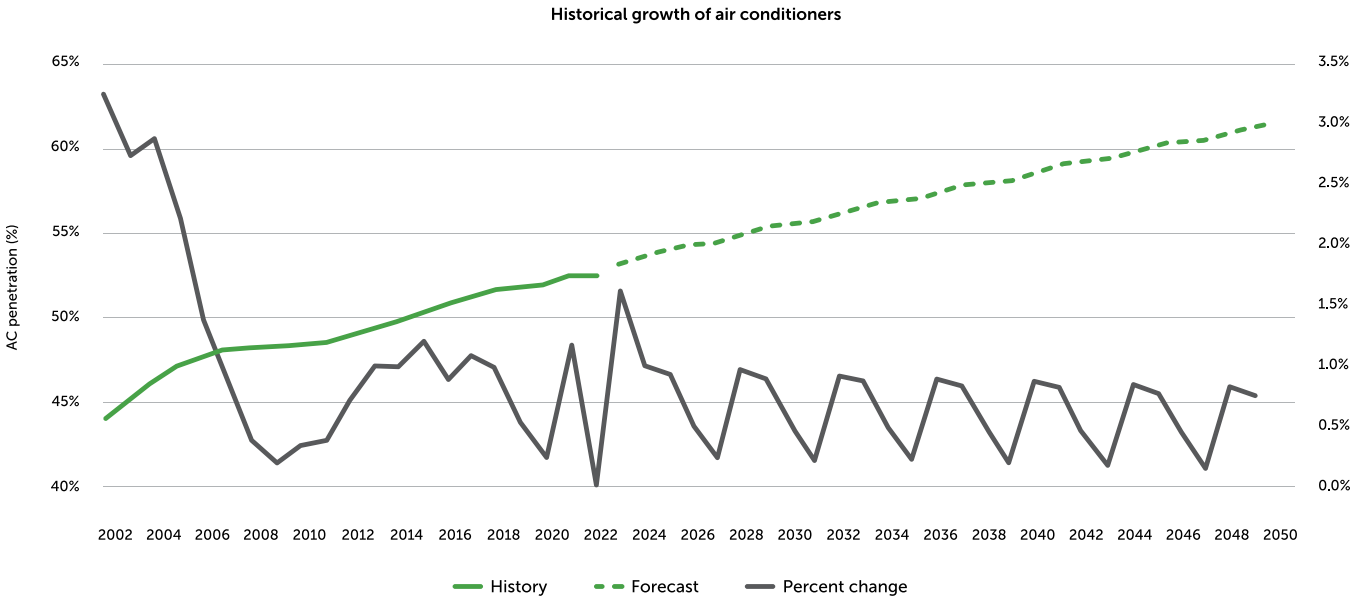


Figure 10. *Historical growth of air conditioners*

5.2.3 Forecast results

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

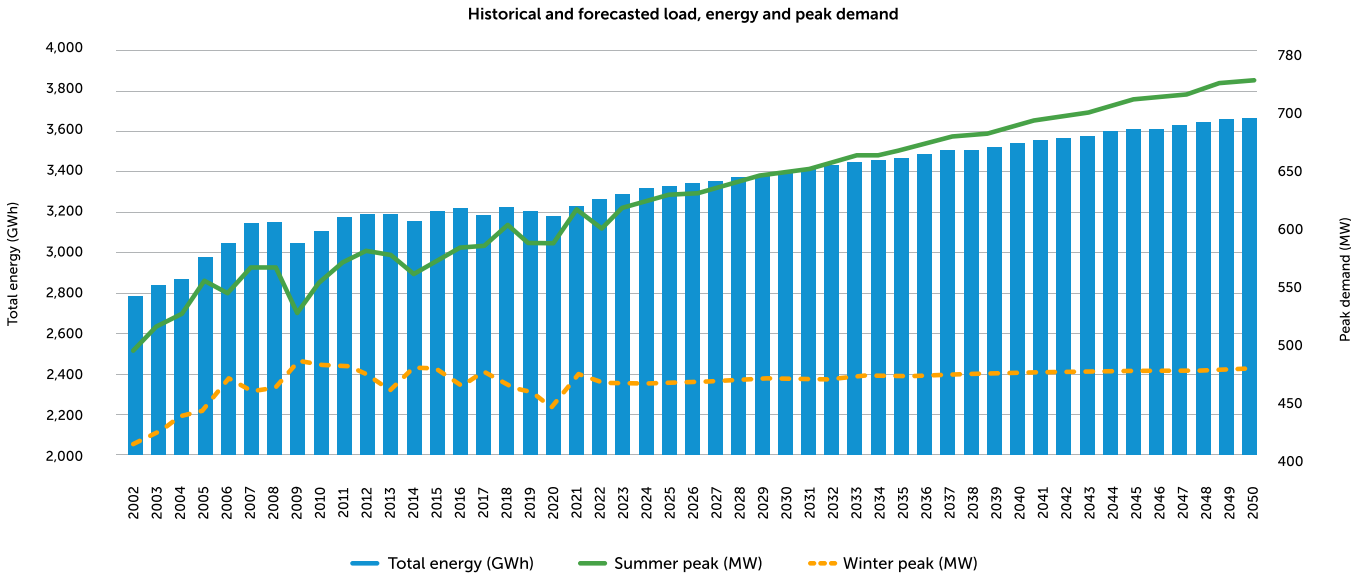


Figure 11. *Historical and forecasted load, energy and peak demand (base forecast without DERs)*

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

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

5.2.4 Hourly load shape

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

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

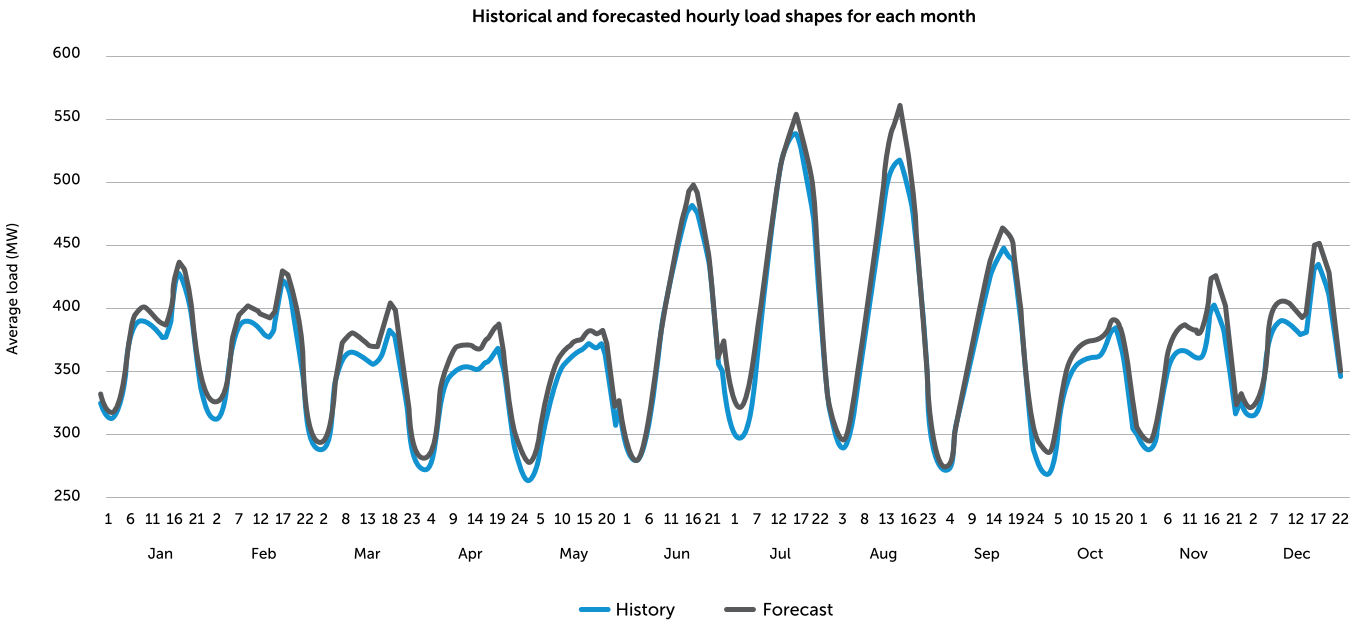


Figure 12. *Historical and forecasted hourly load shapes for each month*

5.3 DER integration, flexible DERs and the virtual power plant

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

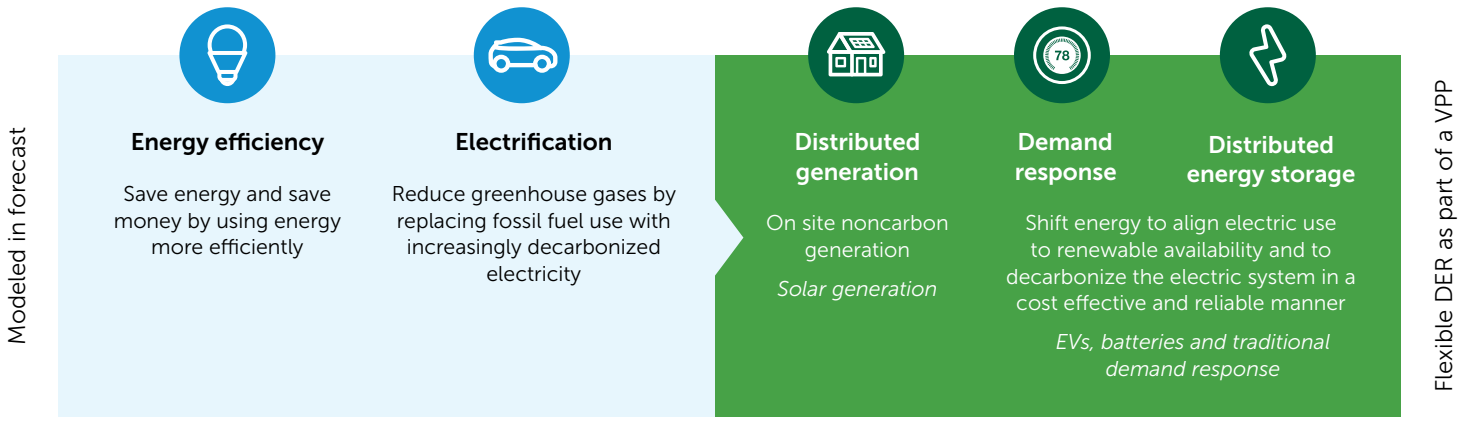
DERs are, as stated in the name, resources. For resources to provide value, they must be put to effective use. Effectively using DERs to provide system-wide benefits is often referred to as "integrating" DERs. Integrating DERs means they have been made a functioning part of the electric system. This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

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

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

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

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



5.3.1 DER forecast studies

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

The Building Electrification Study scope included the following:

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

The DER Study scope included the following:

- Study period: 20 years (2024 through 2043)

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

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

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

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

5.3.2 Energy efficiency

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

5.3.2.1 Energy efficiency forecast study results

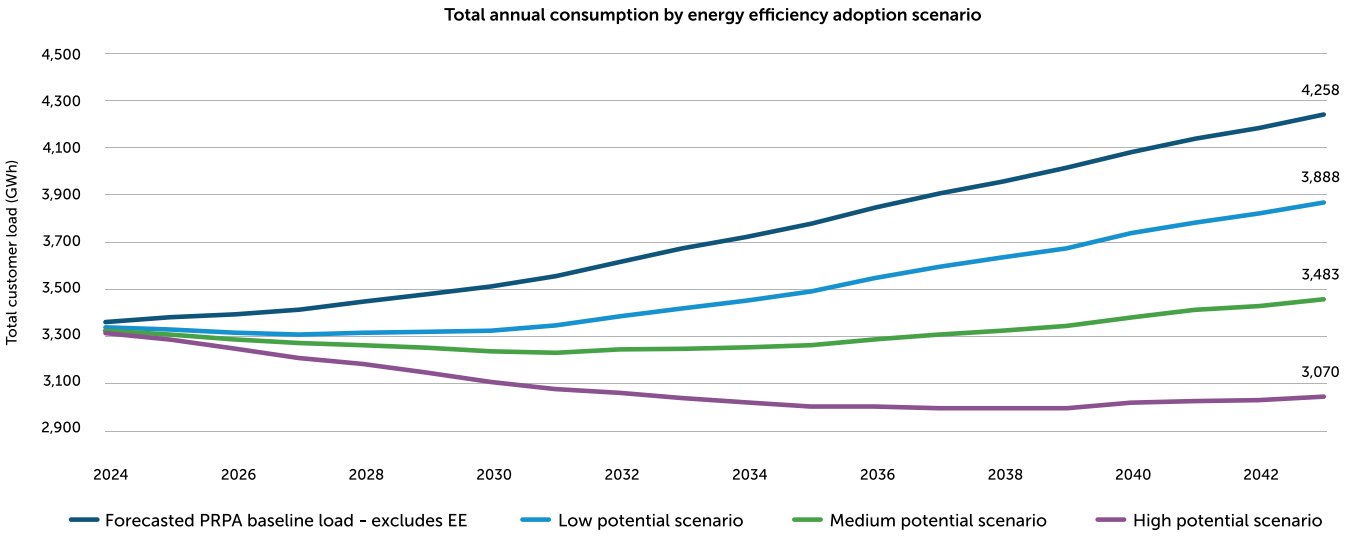
The DER Study evaluated the energy efficiency potential, identifying three adoption scenarios: low, medium and high. The adoption scenarios were evaluated based on three other utility potential studies, taking into consideration local factors, such as the owner communities' customer segmentation, historical participation

data for existing Platte River energy efficiency programs and the building electrification forecast study identifying heat pump adoption rates. Two of the key takeaways from the study include:

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

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

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



Note: The baseline load includes expected customer load growth and electrification growth (PRPA baseline load + building electrification Low projection). Transportation electrification and distributed solar are not included in the baseline load.

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

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

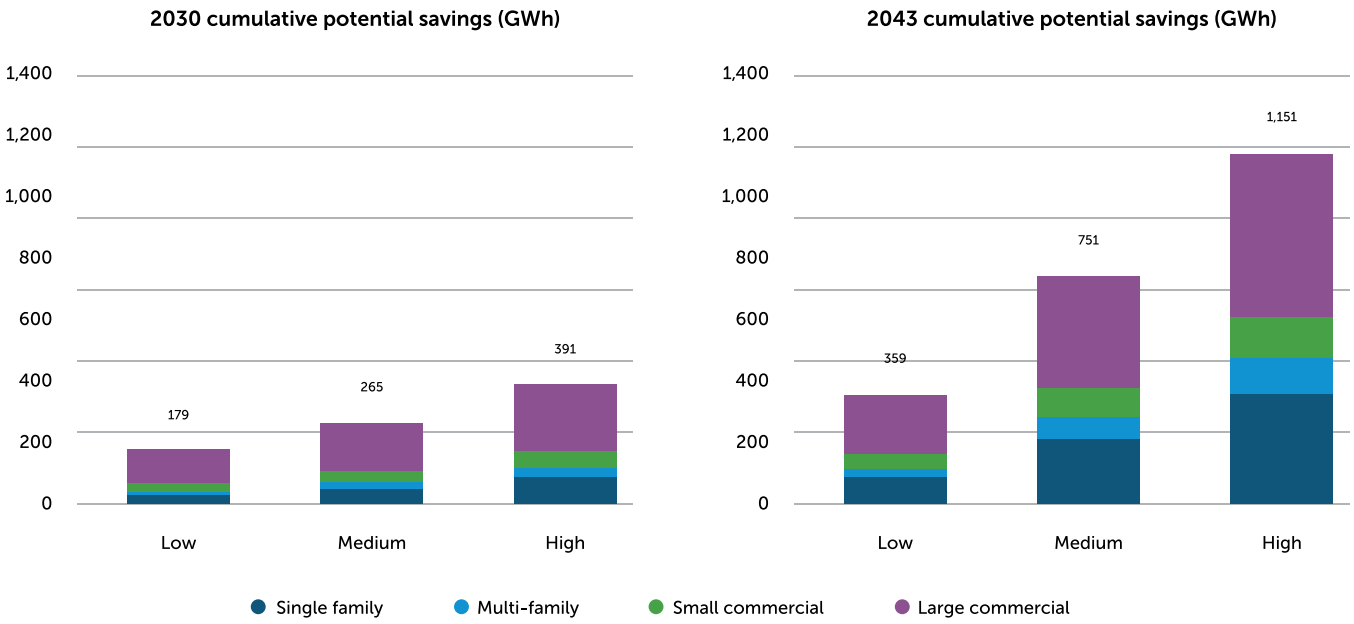


Figure 14. *Cumulative potential savings (GWh)*

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

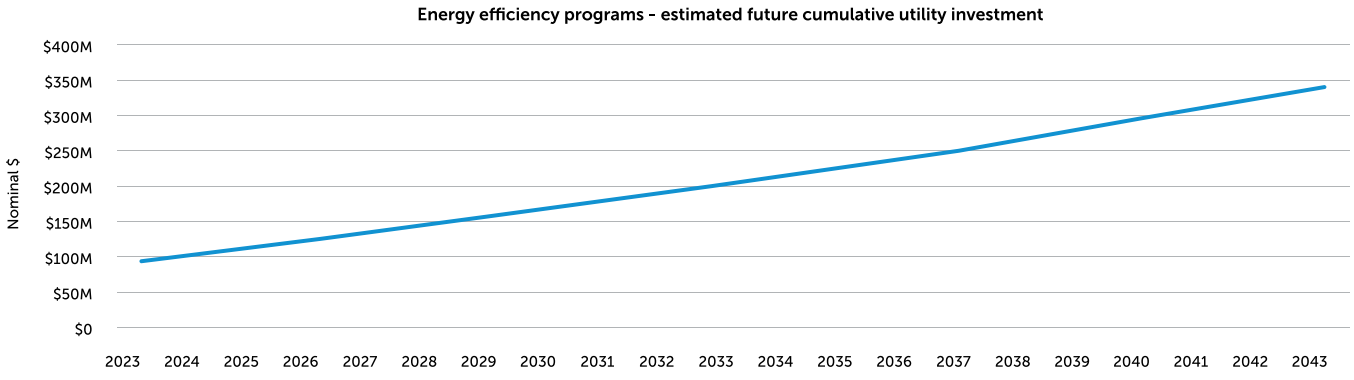


Figure 15. *Energy efficiency programs - estimated future cumulative utility investment*

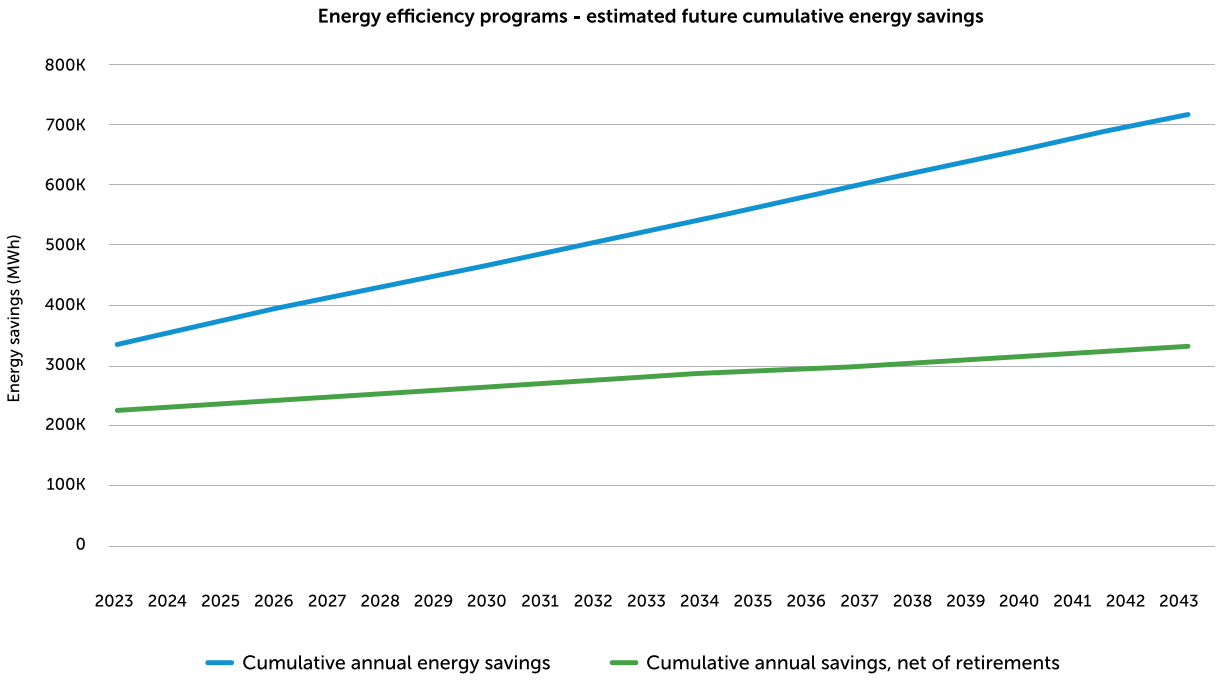


Figure 16. *Energy efficiency programs - estimated future cumulative energy savings*

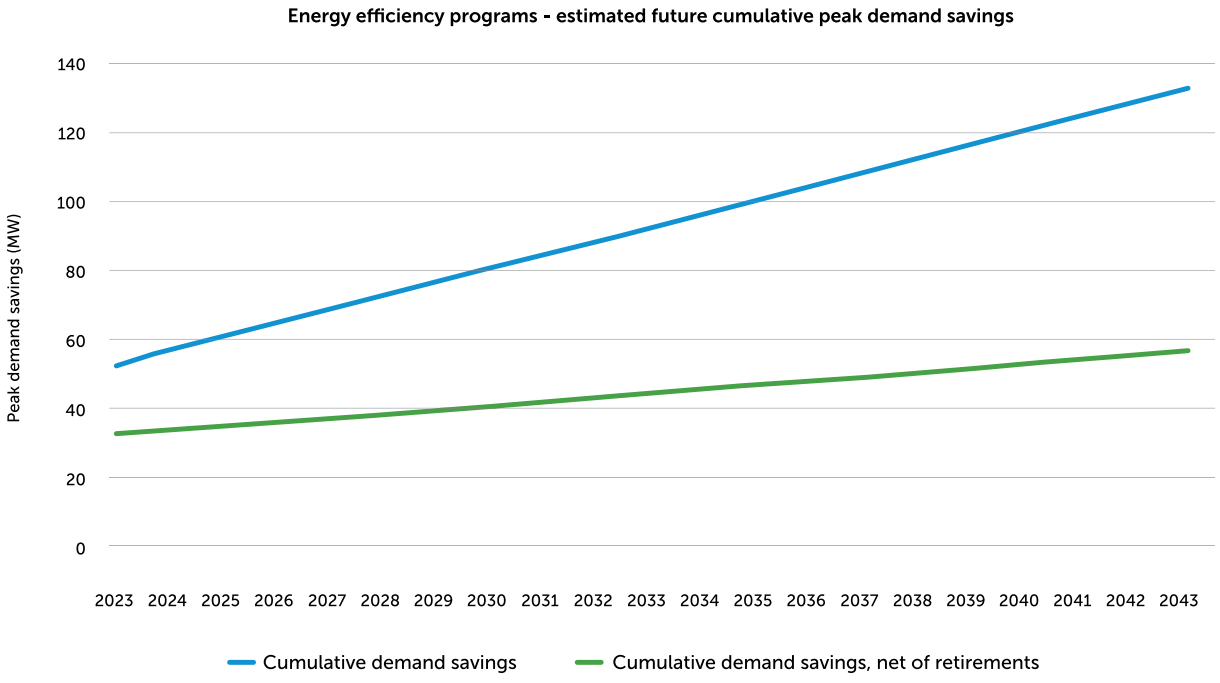


Figure 17. *Energy efficiency programs - estimated future cumulative peak demand savings*

5.3.3 Electrification

5.3.3.1 Buildings

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

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

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

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

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

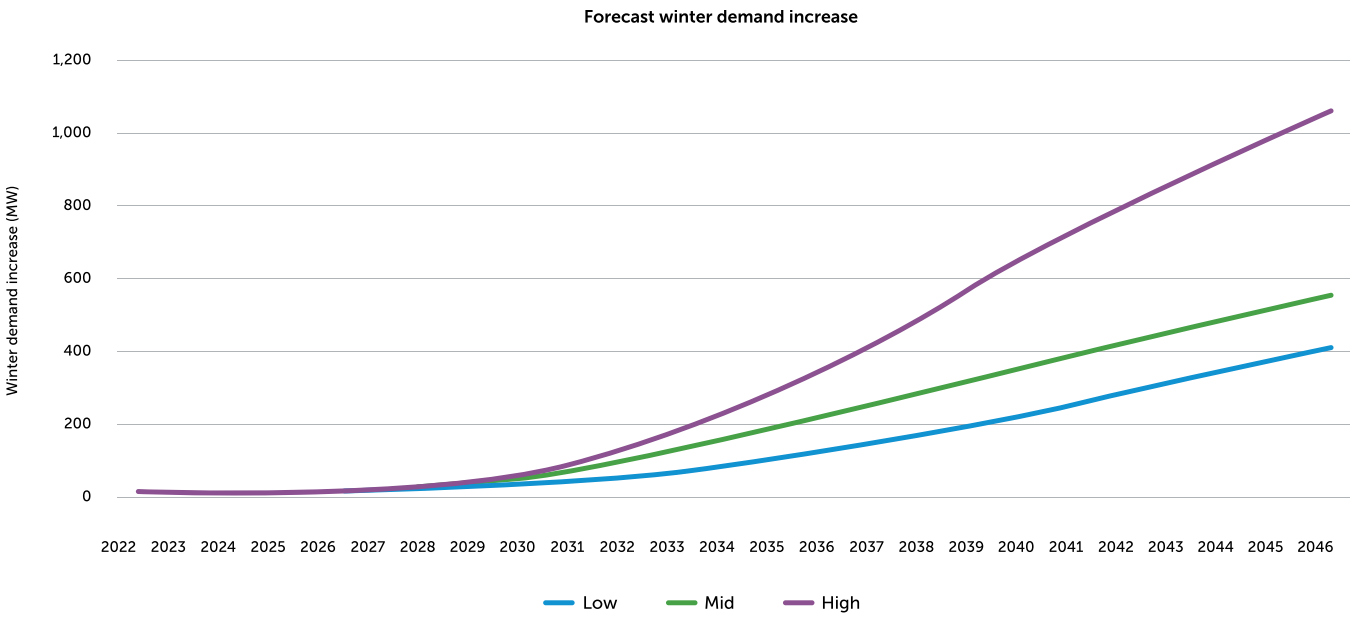


Figure 18. *Forecasted winter demand increase*

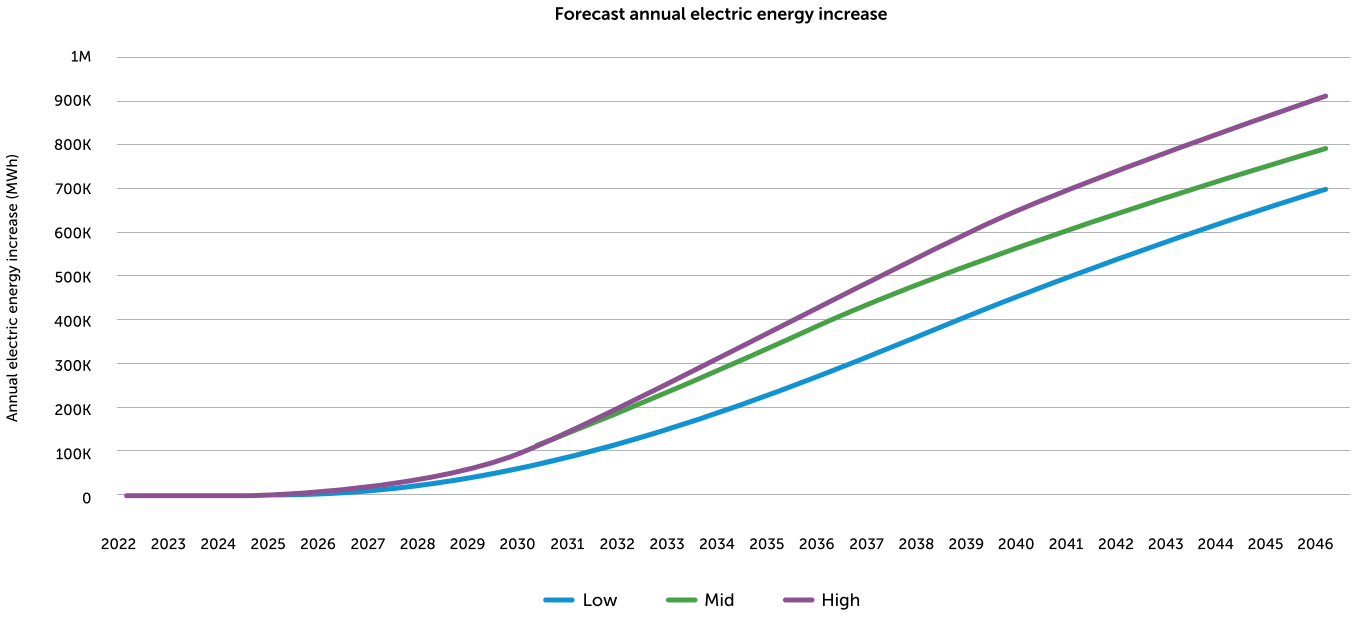


Figure 19. *Forecasted annual electric energy increase*

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

5.3.3.2 Transportation

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

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

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

Table 4. *Primary drivers for transportation electrification*

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

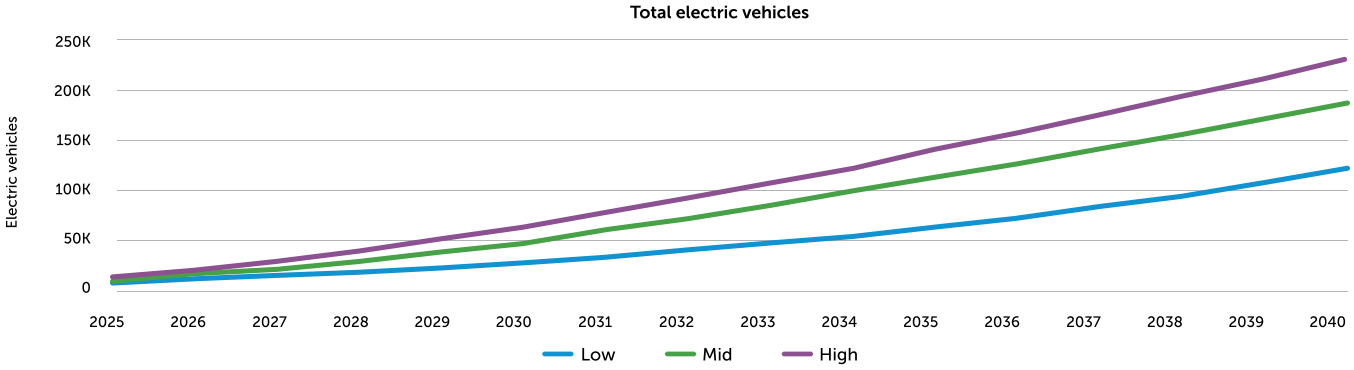


Figure 20. *Total electric vehicles*

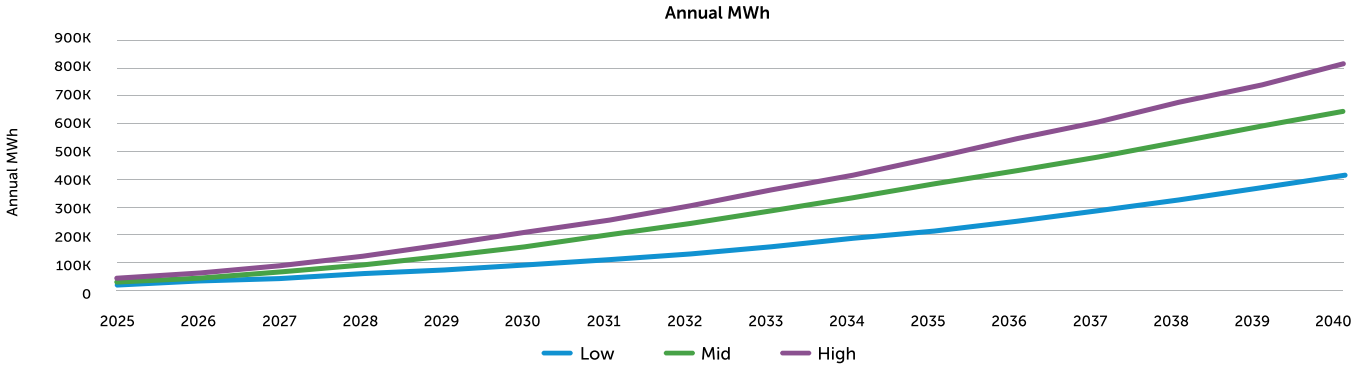


Figure 21. *Annual MWh*

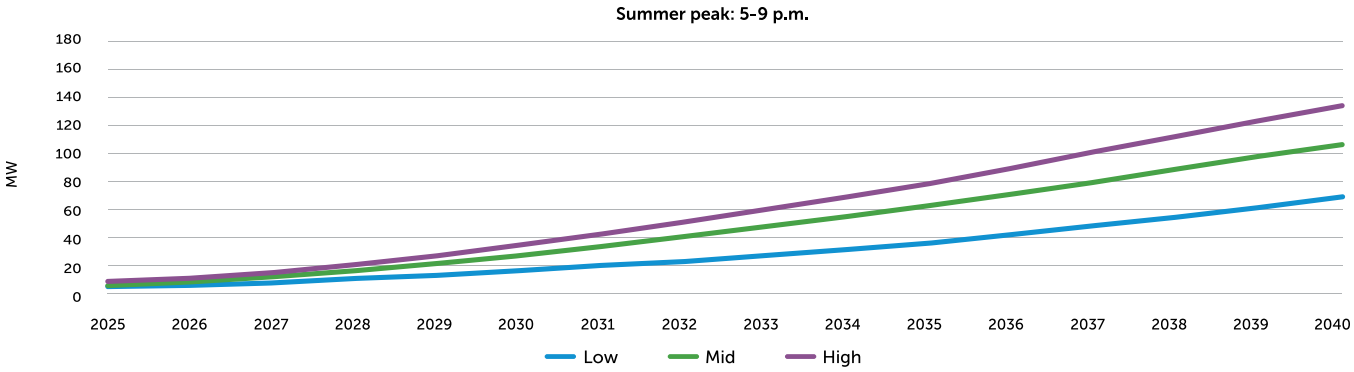


Figure 22. *Summer peak: 5-9 p.m.*

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

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

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

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

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

5.3.4 Transitioning Efficiency Works programs to distributed energy solutions

The Efficiency Works program offerings through Platte River's distributed energy solutions department are shifting focus to meet the customer needs through additional product education,

energy advisory services and repurposing incentives to business and home upgrades that support future load flexibility. A few examples of this transition include:

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

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

5.3.5 New customer programs to address future electrification requirements

5.3.5.1 Building electrification activities

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

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

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

Including income-qualified communities in the energy transition

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

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

5.3.5.2 Transportation electrification activities

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

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

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

5.3.5.3 Commercial HVAC system optimization activities

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

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

5.3.6 Distributed generation and distributed energy storage

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

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

5.3.6.1 Distributed generation solar and distributed storage forecast study results

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

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

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

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

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

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

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

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

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

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

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

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

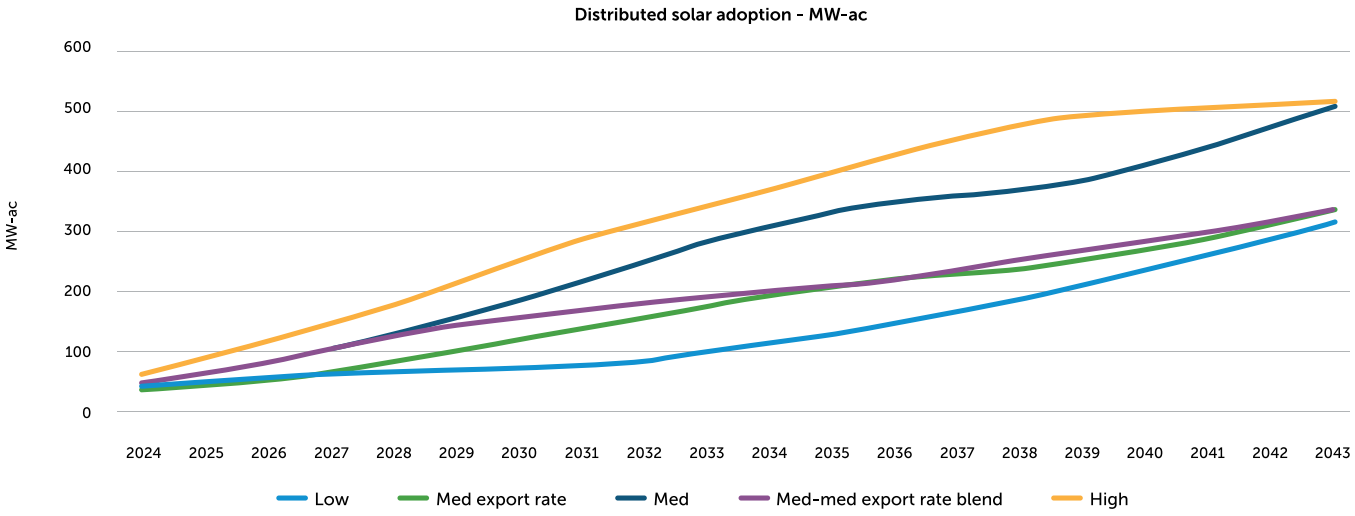


Figure 23. *Distributed solar adoption - MW-ac*

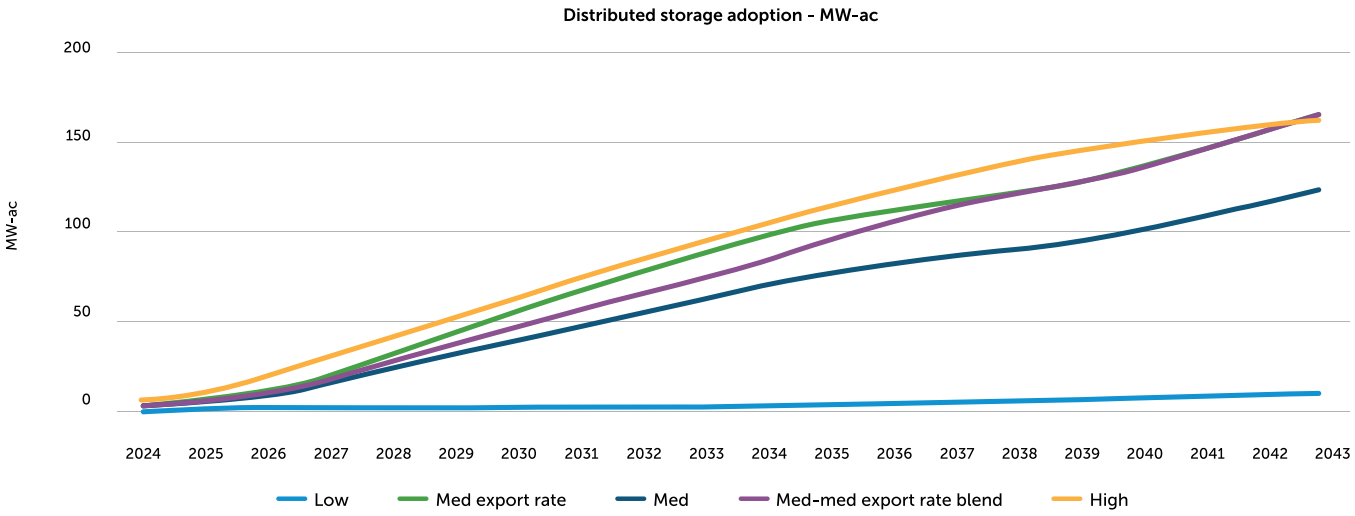


Figure 24. *Distributed storage adoption - MW-ac*

Monitoring and forecasting distributed generation solar and distributed storage adoption. The rise of distributed generation within the owner communities has primarily been driven by individual customers adopting rooftop solar power. Solar energy constitutes around 94% of the existing distributed generation capacity. The remaining capacity is divided among wind (0.02%), cogeneration (4.1%) and hydropower (1%).

Figure 25 illustrates the growth of distributed solar capacity within Platte River's network, fueled by available federal and local incentives, coupled with customers' economics and drive to reduce carbon emissions from electricity generation. As of the end of 2022, estimated distributed solar within Platte River's owner communities totaled 36.3 MW (AC), with 63% from residential solar, 17% from commercial solar, and 20% owned or procured by Platte River or the owner communities.

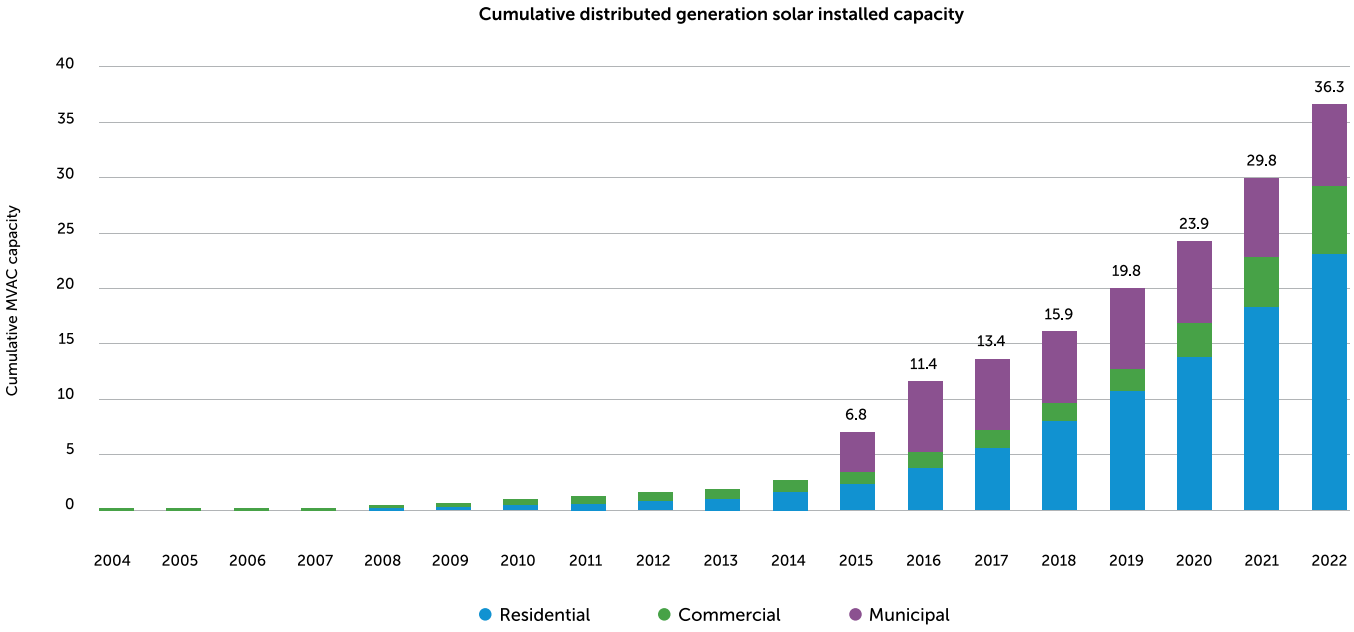


Figure 25. *Cumulative distributed generation solar installed capacity*

Between 2017 and 2022, there has been a notable increase in distributed storage deployment, raising the total capacity to about 1.2 MW in the owner communities. This comprises about 175 systems, averaging a discharge rate of about 7 kW per system. Each year since 2017, there has been an increase in distributed storage system interconnections, with the highest number of installations in 2022. This significant rise highlights the widespread adoption of storage solutions, particularly battery storage, as a versatile tool for providing backup energy and enhancing the operational efficiency of distributed solar systems.

The DER Study evaluated a range of distributed generation solar and distributed storage adoption scenarios to inform the load forecast used for resource planning and to inform DER planning.

Platte River has chosen the blend of the medium and medium-export-rate forecasts. This combination of scenarios represents a gradual change in NEM rates that improves the financial benefit of adopting distributed storage with distributed generation solar. This forecast indicates approximately 155 MW distributed generation solar and 47 MW distributed storage by the end of 2030. This represents 20% annual growth in installed solar capacity and 48% annual growth in storage capacity from current levels. Adoption will continue to be monitored and adjustments will be made to the forecast as more data becomes available.

5.3.7 Flexible DERs and the virtual power plant

As described in previous sections, a VPP is an aggregation of flexible DERs that can be dispatched to support electric system reliability, financial benefits and individual customer benefits. As the name suggests, the VPP can act like a power plant, but it is different in that it is created by thousands of DER devices operating across the electric system. They act in concert, enabled by communication, data collection and management, control and optimization technology.

5.3.7.1 Flexible DER and VPP forecast study results

The DER Study included an assessment of flexible DER that could provide VPP capacity. VPP capacity was evaluated using a multi-step approach that considered the technical, economic and achievable potential of flexible DER technology combined with utility program approaches:

- Technical potential assesses the quantity of flexible DER capacity that theoretically exists in the owner community service territory and how it is expected to grow over time.
- Economic potential considers how much of the technical potential is economic compared to other utility resource options. The study relied on the total resource cost test framework, which compares the marginal costs of a VPP resource for Platte River, the owner communities and their customers to the marginal cost of utility resources.
    - The cost of utility resources included hourly energy costs based on forecasted market energy prices, carbon tax, capacity costs based on four-hour storage and distribution capacity costs based on owner community estimates.
    - The cost of achieving VPP potential included utility program administration costs (excluding incentives) and customer DER technology costs.
    - The cost of achieving VPP potential did not include the cost to the utility of VPP-enabling technology and systems. The need for enabling technology and systems is unaffected by which flexible DER programs Platte River and the owner communities offer.
- Achievable potential considers how much of the economic potential can be realized as a dispatchable VPP capacity at the time of system need and considering customer enrollment rates in VPP program.

The potential study assessed achievable capacity at times of high "net load." This was defined as the load that remains after deducting wind, solar and hydropower. Figure 26 illustrates what this might look like in 2030. Note that while only one day is shown, there are multiple days each summer that would have a similar, though slightly smaller, peak net load. As a result, flexible DER capacity is required many hours throughout the summer. As electrification increases winter loads at a more rapid rate than summer loads, the need for winter dispatchable capacity will grow as well.

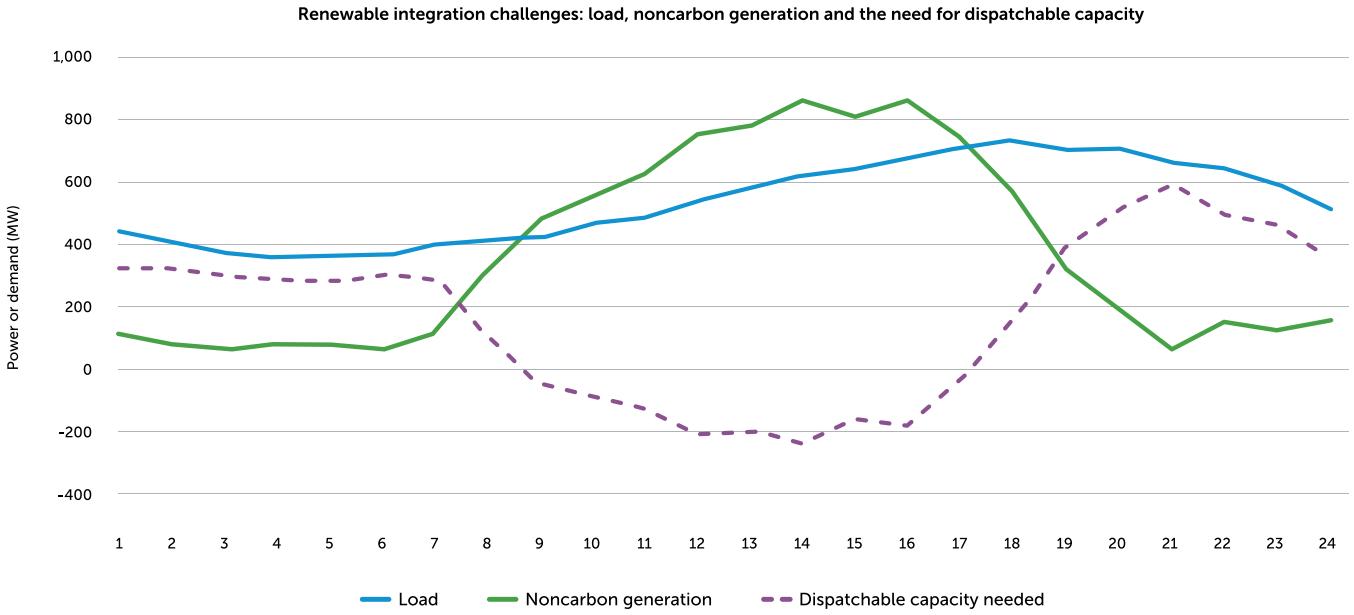


Figure 26. *Renewable integration challenges: load, noncarbon generation and the need for dispatchable capacity*

The DER Study assessed a variety of factors that could drive varying levels of achievable VPP capacity. These were combined in four scenarios as shown in Table 6.

Parameter	Low scenario	Medium scenario	Medium export-rate scenario	High scenario
Time-varying rates	Existing residential TOU rates in Fort Collins only (summer on-peak 2 – 7 p.m.)	New residential TOU rates in all owner communities (summer on-peak 5-9 p.m., aligning with net system peak)	New residential TOU with solar exports valued at forecasted wholesale energy market rates	New residential TOU rates in all owner communities (summer on-peak 5-9 p.m., aligning with net system peak)
Program marketing and incentives	Industry-standard marketing and incentives	Industry-standard marketing and incentives	Industry-standard marketing and incentives	Maximum cost-effective marketing and incentives
Efficiency scenario	Low	Low	Low	High
Electric vehicle scenario	Low	Medium	Medium	High
DS solar and storage scenario	Low	Medium	Medium export-rate	High

Table 6. *Primary drivers of achievable VPP capacity*

Within each scenario, various flexible DER approaches were evaluated in an interactive model to determine how they could be combined to provide a sustained reduction in the system net peak, considering the impact of time-varying rates, direct-control programs and each DER's operating characteristics, as summarized in Table 7.

Measure group	Measure sub-group	Characteristics						
		Curtail-ment potential	Event duration (hours)	Pre-charge time	Pre-charge sizing	Rebound time	Rebound sizing (per hour)	Event frequency (per year)
HVAC controls	Smart thermostats	[75%, 33%]	Up to 2 h	1 h	40%	2 h	30%	20
EV charging	EV smart chargers	100%	4 h +	N/A	N/A	6 h	17%	300+
	Vehicle-to-grid	100%	4 h +	N/A	N/A	6 h	17%	300+
Water heating	Electric water heaters	100%	Up to 4 h	2 h	17%	4 h	17%	15
Other loading flexibility	Large C&I curtailment	25%	Up to 4 h	N/A	N/A	N/A	N/A	15

Table 7. *Flexible DER operating characteristics – load*

Measure group	Measure sub-group	Characteristics					
		Size (kW)	Curtail-ment potential	Round trip efficiency	Typical event duration (hours)	Typical rebound / pre-charge time	Typical event frequency (per year)
Storage	Battery storage - residential	3.3	33%	85%	4 h	4 h	300+
	Battery storage – small commercial	5	100%	85%	4 h	4 h	300+
	Battery storage – large commercial	50	100%	85%	4 h	4 h	300+

Table 8. *Flexible DER operating characteristics – storage*

- For residential, it is assumed 33% of the battery is available for flexible DER program, with the remainder used for customer resiliency.
- For commercial batteries, 100% is assumed available for flexible DER, as batteries are typically used for peak load management, and backup generators are used for resiliency.

As illustrated in tables 7 and 8, the flexibility of EVs and battery storage is apparent, with both having the ability to be dispatched on a near-daily basis, 300 times annually. This provides potential for a highly flexible, available resource that can be used to balance variable noncarbon generation. Flexibility of other DERs, such as HVAC control, large commercial and industrial curtailment and water heater control will be limited due to impacts on comfort and productivity.

Figures 27 and 28 summarize the resulting achievable capacity for each of the cases, as well as the annual costs in 2030 and 2040. Program costs are strictly incentives and program administration. They do not include VPP system costs. Growth from 2030 to 2040 was driven largely by increasing adoption of battery storage and EVs.

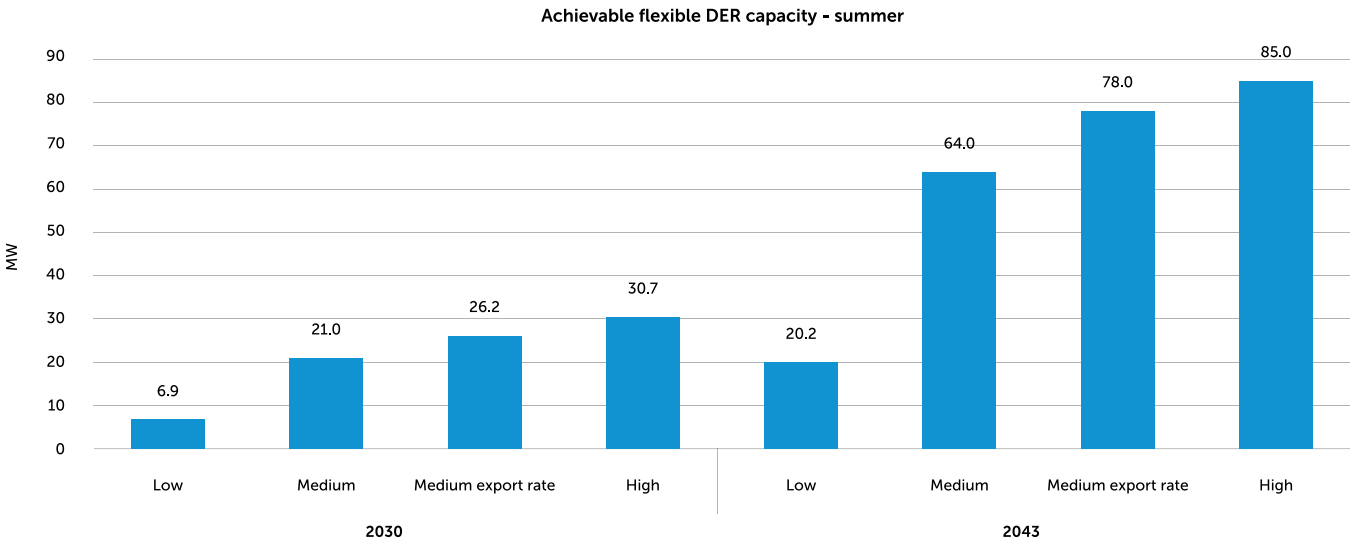


Figure 27. *Achievable flexible DER capacity - summer*

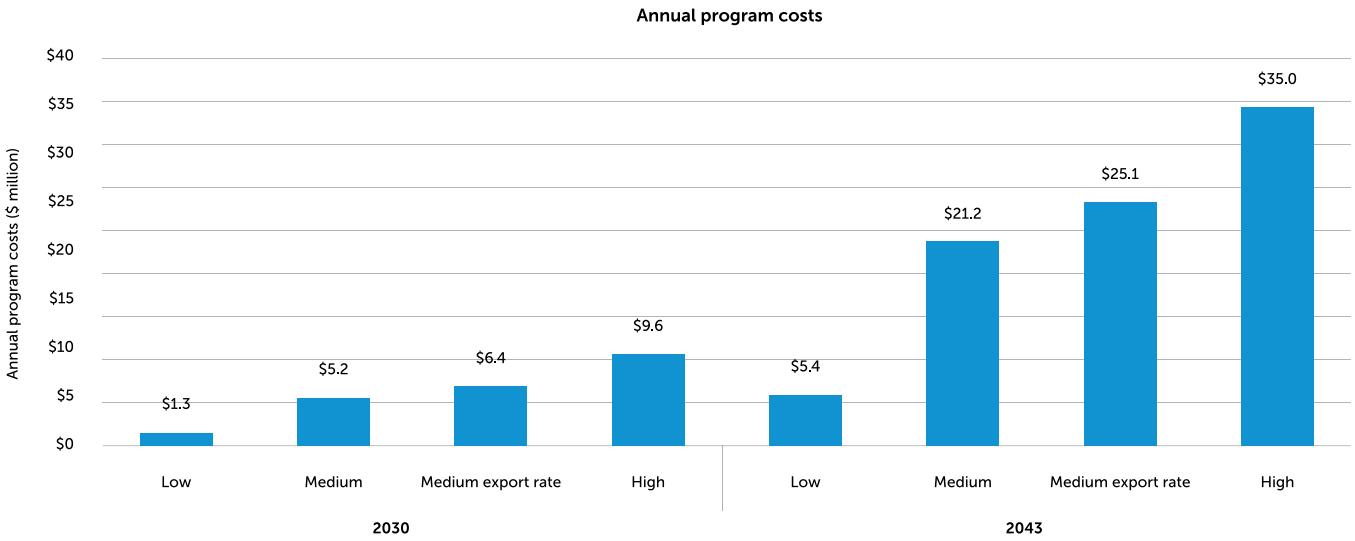


Figure 28. *Annual program costs*

Key takeaways from the DER Study include:

- Summer peak load reductions range from 6.9 MW to 30.7 MW across the different scenarios in 2030.
- The commercial sector is forecasted to have the greatest potential for the low scenario while the residential sector overtakes commercial in the medium and high cases, due to increasing adoption of EVs and distributed storage.
- For the residential sector, battery storage is expected to be by far the most prominent measure in all scenarios except the low one, followed by smart EV chargers and AC smart thermostats in the summer and electric resistance smart thermostats in the winter.
- The commercial demand response potential is primarily driven by large commercial and industrial opportunities, followed by battery storage and water heating.

Develop and implement VPP customer programs. Customers who have flexible DERs and are willing to enroll them in the VPP provide the engine for the VPP's operation. Therefore, a major focus of Platte River and the owner communities is to develop customer programs that support customer enrollment and ongoing participation.

Customer programs must support Platte River's pillars of providing reliable, environmentally responsible and financially sustainable energy, while also providing benefits to participating customers. The DER Study has identified the following opportunities for flexible DERs that can participate in the VPP:

- **Distributed storage management.** Distributed storage is expected to grow significantly, often paired with distributed generation solar.
- **EV charge management (including vehicle-to-grid when available)**. EV

adoption is expected to grow significantly, providing a large and highly flexible load for the VPP. Vehicle-to-grid is also anticipated to grow, with the potential of providing additional storage to the grid.

- **Large commercial and industrial customer custom demand response.** These customers are likely to have large and sometimes unique DER opportunities. Platte River anticipates developing custom approaches to support these projects similar to the custom, pay-for-performance incentives currently offered for efficiency improvements.

- **HVAC demand response.** HVAC demand response programs manipulate electric load for heating and cooling buildings for short periods of time, either through direct control of the heating or cooling system components (for example, compressor load-control switches) or increasingly, through wi-fi enabled thermostats ("smart thermostats").

- **Electric water heater demand response and storage.** Electric water heater demand response takes advantage of the storage that is typically integral to the water heat to allow active heating to be curtailed for brief periods.

Taken together, these customer resources are anticipated to provide a VPP capable of dispatching 32 MW of capacity by 2030 and 93 MW by 2040. To improve the availability of this capacity, Platte River anticipates enrolling more DER capacity than these values indicate. This is to account for limitations on the flexibility of DERs to consistently provide capacity during the evening peak while respecting customer restrictions on Platte River's and the owner communities' use of their flexible DERs. As a result, the enrolled capacity of customer resources may reach an estimated 71 MW by 2030 and 204 MW by 2040. As experience is gained operating the VPP, it is possible that other uses for the enrolled capacity may emerge.

In addition to the customer resources, the VPP is anticipated to include other flexible DERs developed by Platte River and the owner communities. Platte River is in developing plans for 20 MW of distribution-scale storage to be located within the owner communities. This is expected to bring the total achievable VPP capacity to about 52 MW by 2030 and 113 MW by 2040.

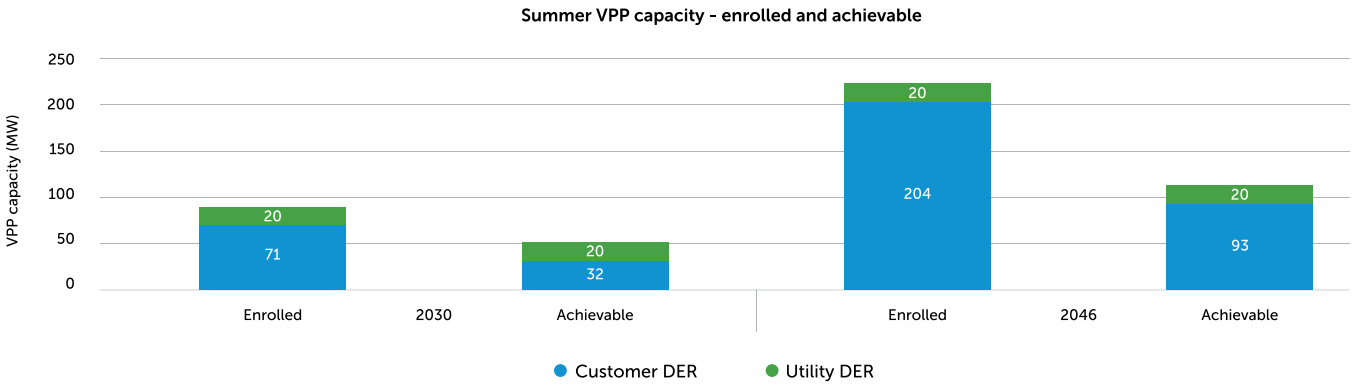


Figure 29. *Summer VPP capacity - enrolled and achievable*

Achieving a VPP of this magnitude requires a high level of customer participation. The enrolled capacity is projected to include 50,000 DER devices by 2030 and close to 100,000 devices by 2040, drawn from the owner communities' customer base of about 172,000 customers. To achieve this high level of participation, Platte River will collaborate with the owner communities to support customers on their DER journeys. This includes engaging customers as they evaluate their DER options and consider enrollment in the VPP. It is also expected to include providing incentives for enrollment and ongoing participation based on the system benefits their DERs can provide. In addition, Platte River and the owner communities will need to engage with the local, regional and some national market actors in the manufacturing, distribution, sales, installation, and operation of DERs.

Platte River issued an RFP in May 2024 to identify firms experienced in providing VPP customer program deployment to provide a rapid, cost-effective, and customer-focused portfolio of VPP programs.

5.3.8 Summary of selected scenarios for DER and VPP potential

Platte River evaluated a range of DER potential scenarios, ranging from low to high. Table 9 summarizes the scenarios selected for each type of DER and describes the reason the scenario was selected.

DER type	Selected scenario	Description
Energy efficiency	Low	Low scenario is most consistent with current participation levels, even as Efficiency Works offers some of the highest efficiency incentives in the state.
Building electrification	Medium	Medium scenario is most consistent with observed adoption rates and with increasing local, regional and national support for electrification.
Transportation electrification	Medium	Medium scenario is most consistent with observed adoption rates and with increasing local, regional and national support for electrification.
Distributed generation and storage	Medium-medium export rate	A hybrid scenario starting with medium and shifting to medium export rate was used to reflect current adoption trends and anticipated shifts in net metering policy to favor storing excess solar rather than exporting it.
Virtual power plant / flexible DERs	Hybrid – see description	A hybrid scenario was defined in part by the DER adoption scenarios described above. In addition, EVs that the study assumed would respond to time-varying rates were instead reclassified as being under direct load management to provide greater responsiveness to varying system conditions. The result is that the selected VPP potential is close in magnitude to the high scenario.

Table 9. *Summary and logic for selected scenarios*

5.4 Load forecast with DER (final) 2024-2043

Section 5.2 of this chapter covered load forecast before considering the impact of DERs. In section 5.3, we covered different DERs and saw how much energy and peak demand they contribute (like distributed solar or demand response) and require from the system (like EVs and building electrification). This section discusses the energy and peak demand contribution of each DER and the composite load forecast including the contributions from all the DERs. The composite load forecast, including energy and peak demand, was used in the Plexos model to develop a supply-side portfolio.

5.4.1 Energy contributions of DER

5.4.1.1 Distributed generation

Figure 30 shows the energy contribution from distributed generation, primarily distributed solar. This is shown as negative because it represents the reduction in customer energy needs from Platte River's supply. The bars show energy in gigawatt-hours (GWh) and the solid line shows percent reduction in total Platte River energy. By 2030, distributed generation energy is expected to reduce base energy by 6% and by the end of planning horizon in 2043, it is expected to reduce the predicted base energy by about 13%. Distributed solar produces more energy in summer and less energy in winter but these are annualized values.

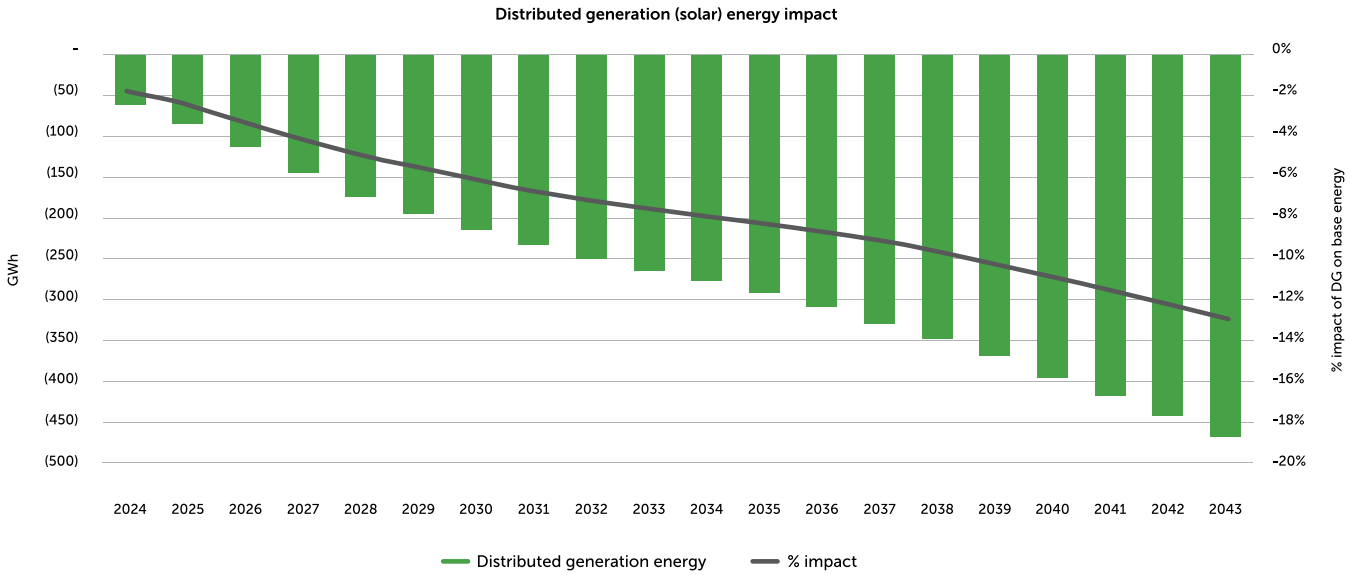


Figure 30. *Distributed generation (solar) energy impact*

5.4.1.2 Building electrification

As illustrated in Figure 31, building electrification (mostly consisting of heating load) starts from a very small level but is expected to grow rapidly in the next decade. The bars show energy in GWh and the solid line shows the percent increase in the base energy forecast. By 2030, building electrification is expected to increase base energy by 3% and by the end of the planning horizon in 2043, it is expected to add about 19% to the predicted base energy. Because it is heating load, most of the building electrification energy requirements will be in winter, but we show annual values in the chart.

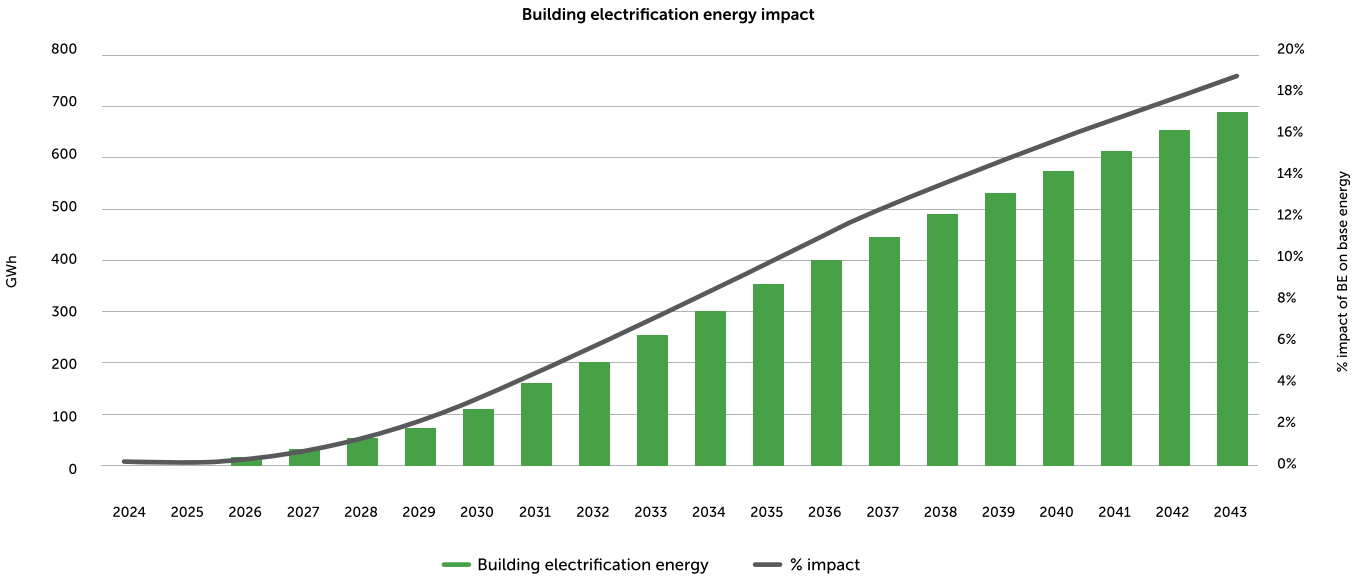


Figure 31. *Building electrification energy impact*

5.4.1.3 Electric vehicles

As illustrated in Figure 32, EV load starts from a very low level but is expected to grow rapidly in the next decade. The bars show energy in GWh and the solid line shows percent increase in the base energy forecast. By 2030, EV is expected to increase base energy by 5% and by the end of the planning horizon in 2043, it is expected to add about 23% to the predicted base energy. These are annual values. EV load is evenly distributed across the year. A portion of the EV load is flexible and exact charging time can be managed by the utility to more opportune times.

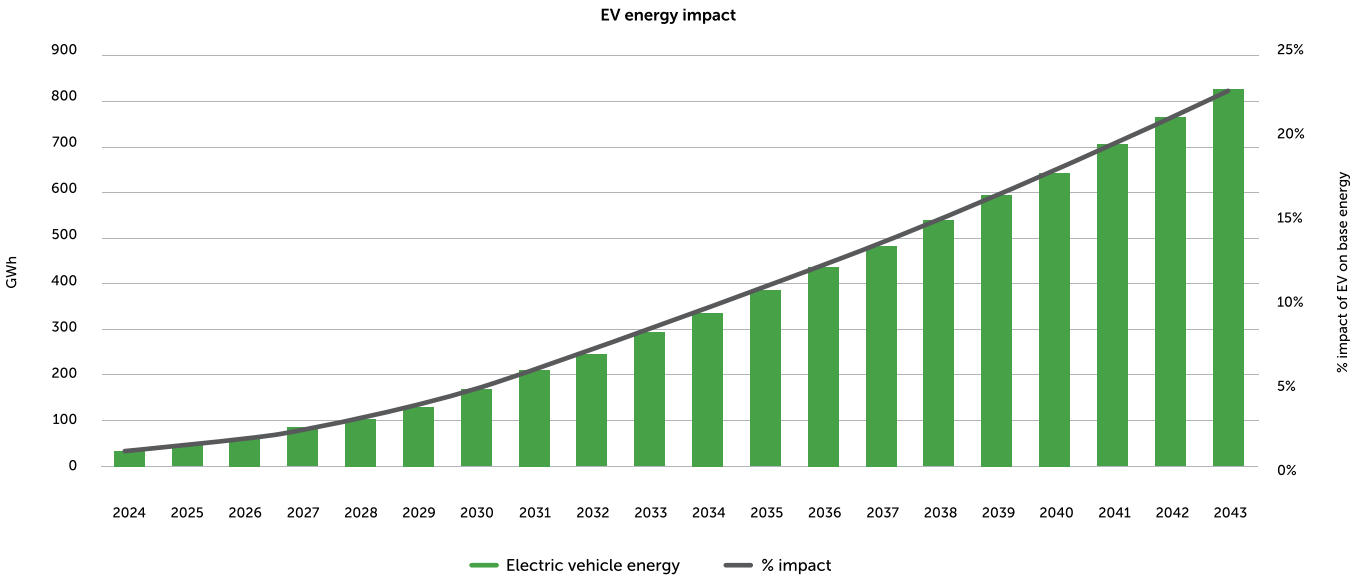


Figure 32. *EV energy impact*

5.4.2 Capacity contribution of DER

5.4.2.1 Distributed generation

Figure 33 shows the summer peak capacity contribution from distributed generation. This is shown as negative because this is the reduction in customer peak demand due to the rooftop solar. The bars show summer peak capacity in megawatts and the solid line shows percent reduction in total Platte River annual summer peak demand. By 2030, distributed generation is expected to reduce summer peak by 2% and by the end of planning horizon in 2043, it reduces the predicted summer peak by about 3.4%. Although the absolute megawatt addition of rooftop solar is large, its impact on the summer peak is small due to low Effective Load Carrying Capability (ELCC) value of distributed solar (like utility scale solar). Basically, the incremental contribution of solar to reduce summer peak becomes negligible to zero as more solar is added and the peak hour moves closer to the sunset.

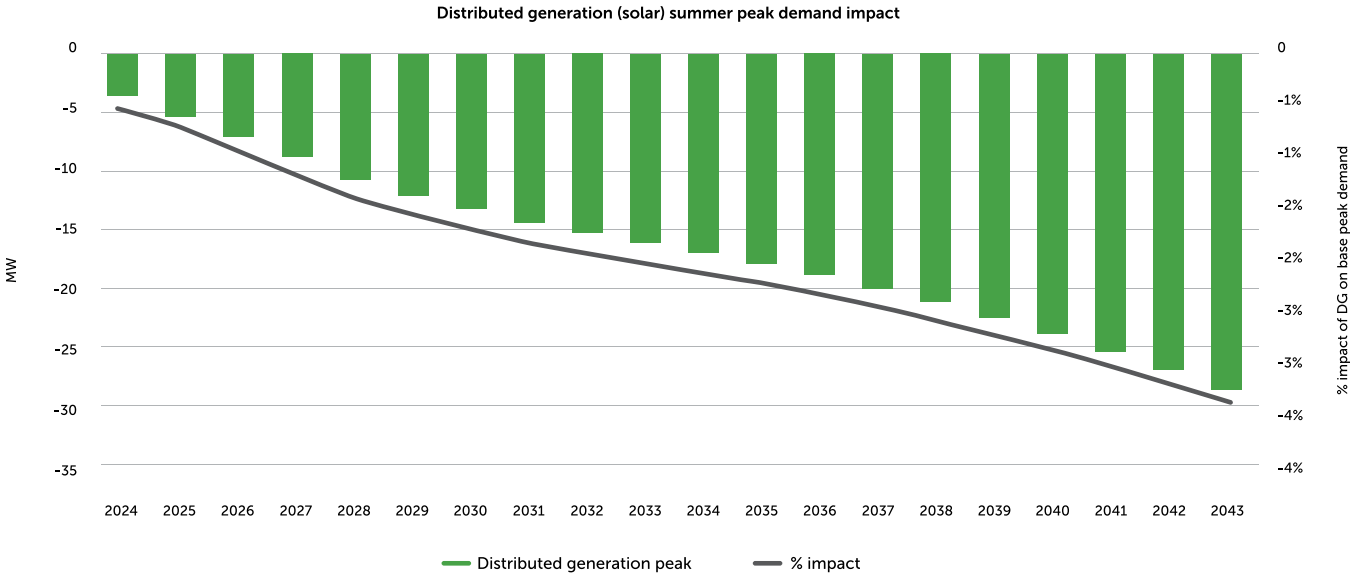


Figure 33. *Distributed generation (solar) summer peak demand impact*

5.4.2.2 Demand response

Figure 34 shows the summer peak capacity contribution from demand response or flexible resources such as home battery storage and EV charging load. This is shown as negative because it represents the reduction in overall customer peak demand. The bars show summer peak capacity in megawatts and the solid line shows percent reduction in total Platte River annual summer peak demand. By 2030, demand response is expected to reduce summer peak by 5% and by the end of planning horizon in 2043, it reduces the predicted summer peak by about 9%.

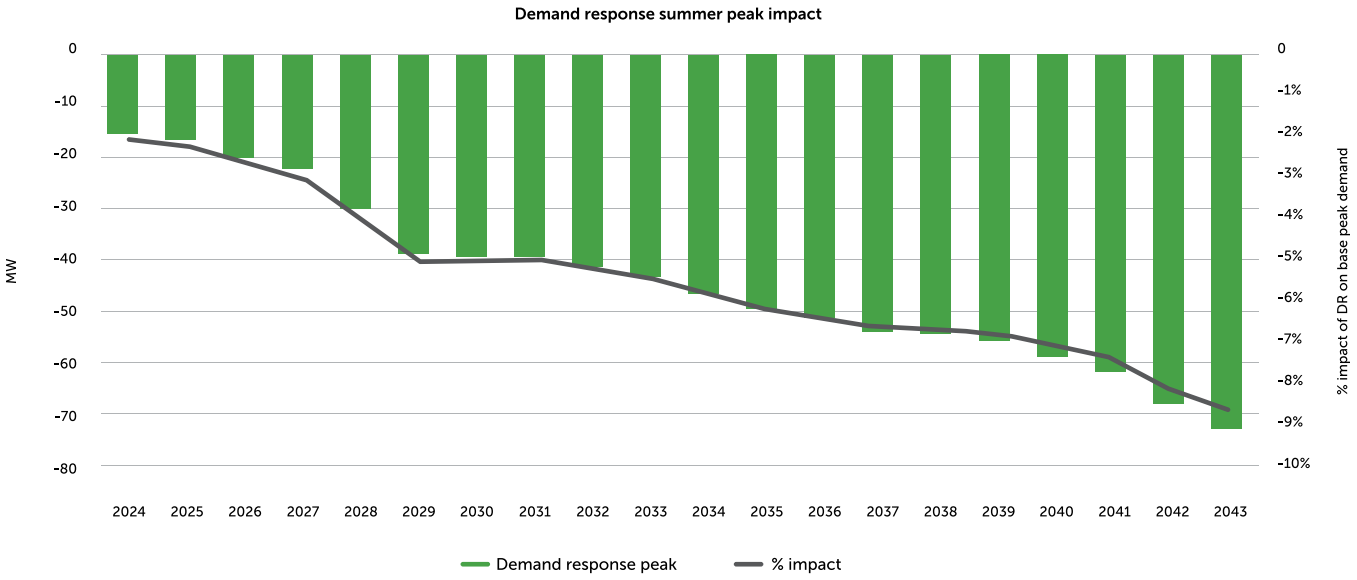


Figure 34. *Demand response summer peak impact*

5.4.2.3 Building electrification

As illustrated in Figure 35, building electrification starts from a very low level but is expected to grow rapidly in the next decade. Most building electrification contribution is from heating systems in colder months, so the impact on summer peak demand is fairly small, mainly coming from electric cooking and water heating. The bars show summer peak hour building electrification load in megawatts and the solid line shows percent increase in the base peak demand. By 2030, building electrification is expected to increase summer base peak by about 1% and by the end of the planning horizon in 2043, it adds about 3% to the predicted base summer peak demand.

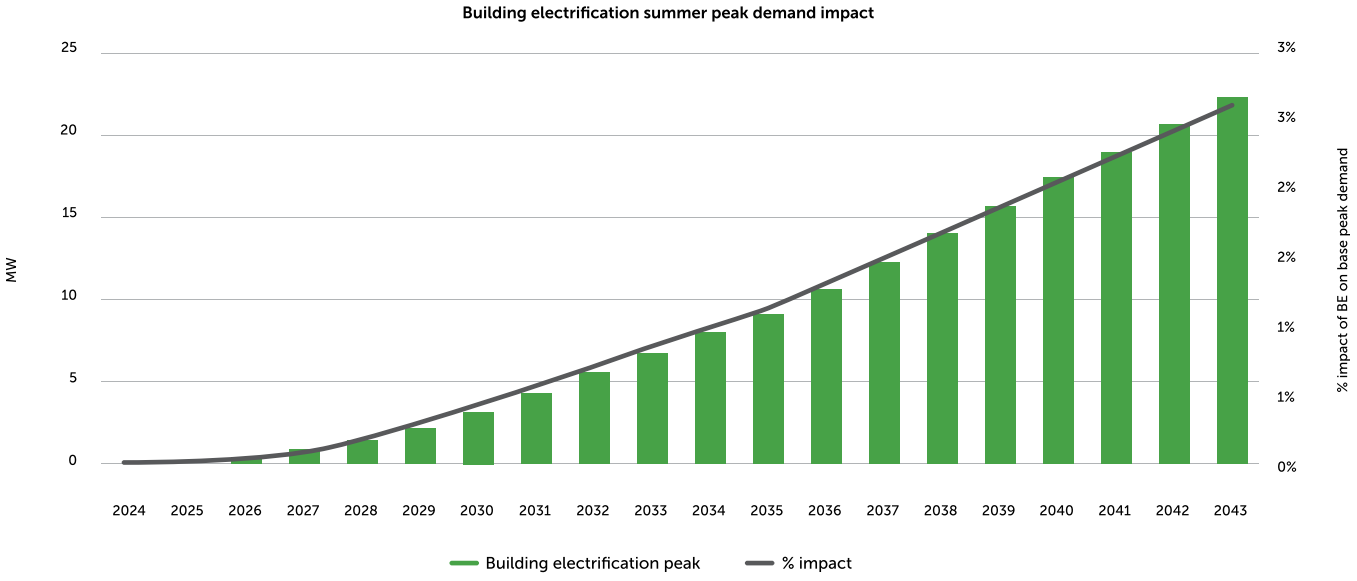


Figure 35. *Building electrification summer peak demand impact*

5.4.2.4 Electric vehicles

As illustrated in Figure 36, electric vehicle load starts from a very low level but is expected to grow rapidly in the next decade. This figure shows the portion of the EV load that is inflexible and cannot be managed or moved away from the summer peak hour. The bars show summer peak capacity in megawatts and the solid line shows percent increase in the summer base peak demand forecast. By 2030, EV is expected to increase summer base peak demand by 3% and by the end of the planning horizon in 2043, it adds about 15% to the predicted base summer peak demand. It is important to note that most EV load is flexible, and its exact charging time can be managed by the utility to lower summer peak demand. Contribution from the flexible EV charging load is not included in the chart below because we assume it will be controlled at the time of summer peak hour and moved to a later, lower-demand hour.

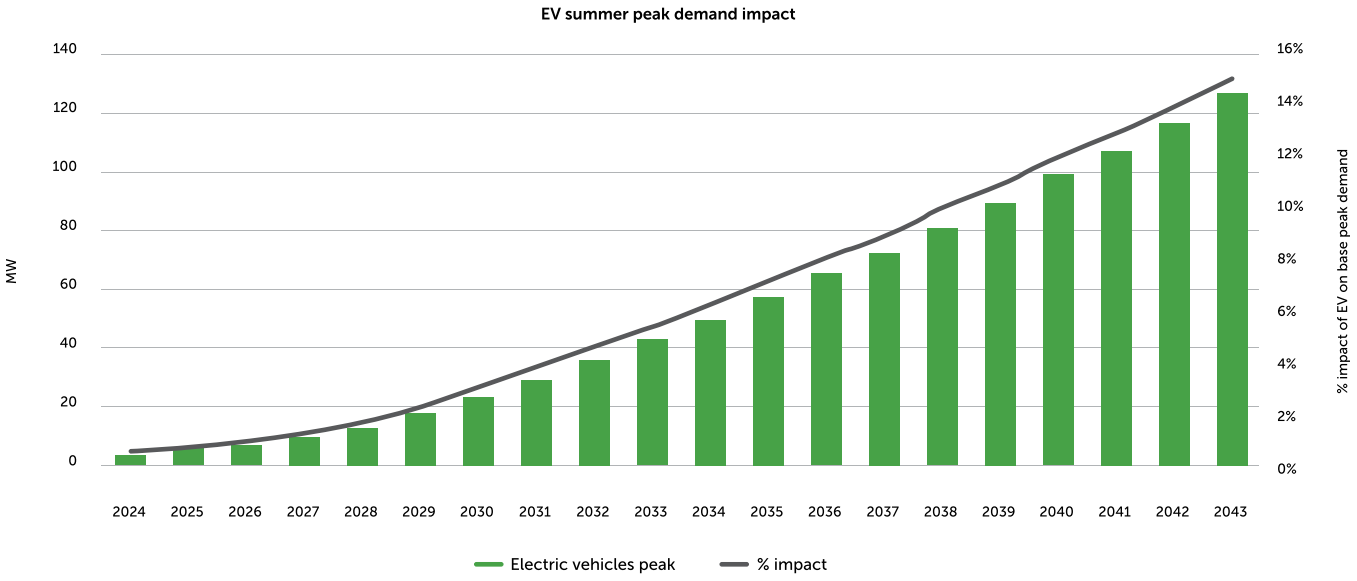


Figure 36. *EV summer peak demand impact*

5.4.3 Composite load with all DER contributions

Collectively, DERs decrease electric consumption and load growth in early years, due to the presence of distributed generation resources like rooftop solar and demand response programs, offsetting additional load created by electric vehicles and building electrification. However, as adoption of electric vehicles and building electrification increase, the additional load outpaces growth in distributed generation, resulting in higher load growth. The combined DER impact trend is similar for annual energy and summer peak demand but the percent impact varies. Figure 37 shows composite annual energy requirements and the combined percent impact of DERs.

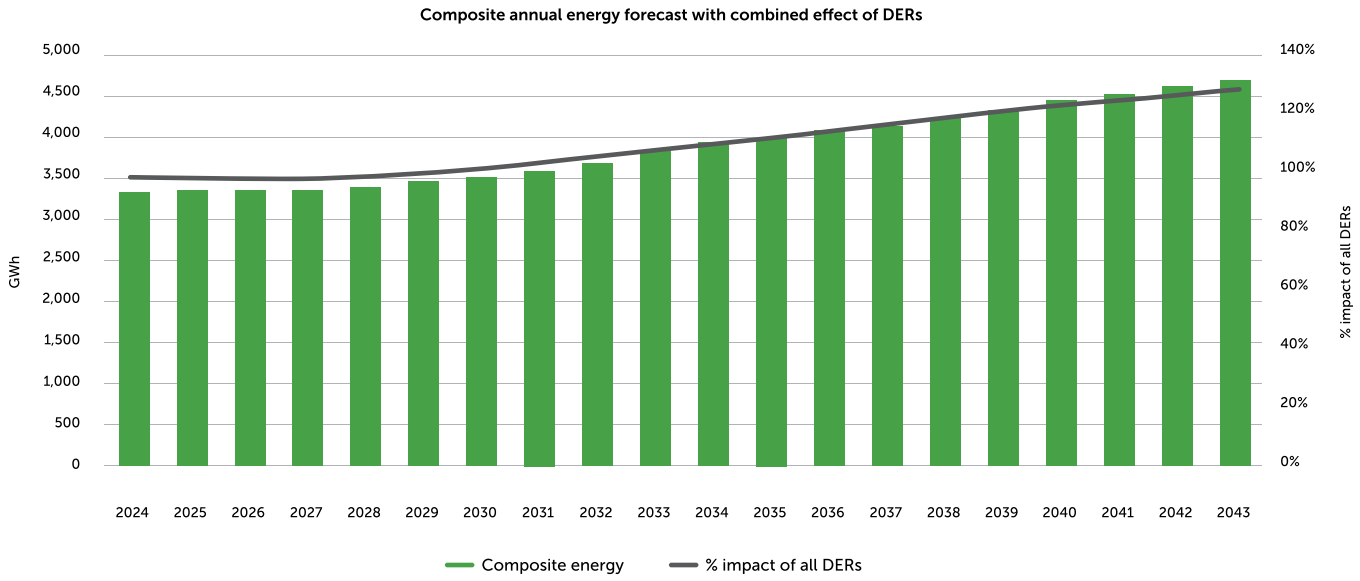


Figure 37. *Composite annual energy forecast with combined effect of DERs*

The green bars in Figure 37 show composite annual energy in gigawatt hours that Platte River's supply system must produce, and the solid black line shows the combined impact of all DERs as a percent. The combined effect of DERs reduces the annual energy need through 2029 and increases it afterwards, due to rapid increase in building electrification and EV load, reaching an almost 29% increase by 2043.

Figure 38 shows composite summer peak requirement and the combined percent impact of DERs. The green bars show composite summer peak demand in megawatts that Platte River's supply system must provide, and the solid black line shows the combined impact of all DERs. The combined effect of DERs reduces the summer peak demand through 2035 and increases it after, due to rapid increase in building electrification and EV load, reaching an almost 6% increase by 2043. The combined percent impact of DERs on summer peak demand is much lower than the percent impact on annual energy consumption because the two major DERs, EV and building electrification, do not increase the summer peak load as much as they increase annual energy consumption.

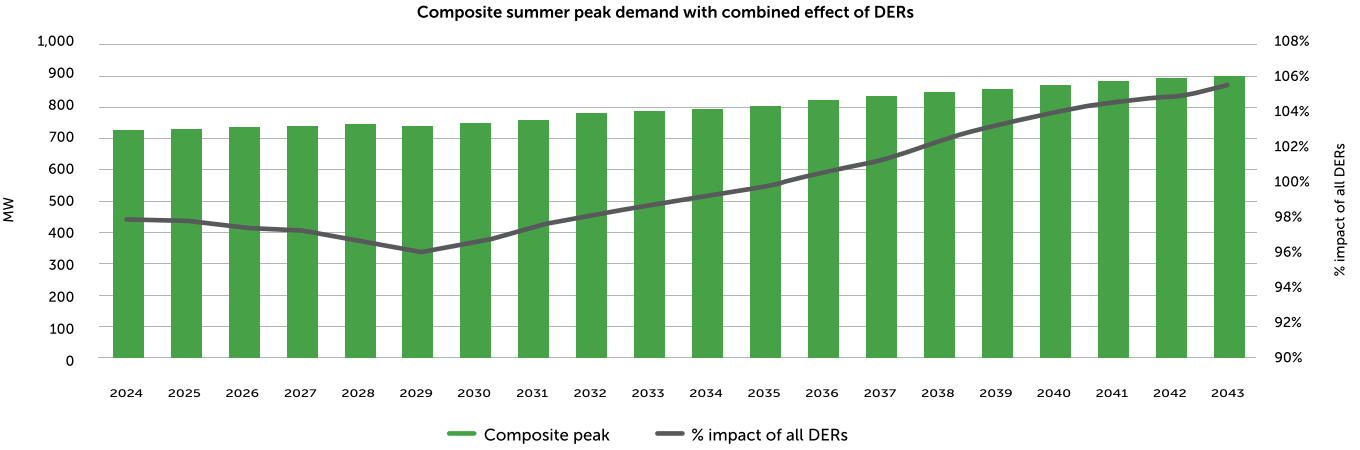


Figure 38. *Composite summer peak demand with combined effect of DERs*

06 Supply-side assumptions

This section reviews assumed supply-side resources available to serve projected demand. These assumptions include commodity fuel prices, resource costs and their future trajectory, as well as assumptions about how Platte River interacts with other power suppliers in our region. The study period spans 20 years starting Jan. 1, 2021, largely because the typical life of investments for new generating capacity is 20-30 years.

6.1 Commodity price projections

Commodity price projections are a key input to resource planning. Platte River engaged Siemens Energy Business Advisory (previously Pace Advisory or Siemens) to provide regional natural gas, power, carbon dioxide (CO2), nitrogen oxides, sulfur dioxide (SO2), and mercury cost projections. Platte River projected coal prices based on unique coal supply plans for its coal-fired generation fleet. The following subsections discuss these commodity price projections in more detail.

6.1.1 Natural gas prices

Siemens provided a monthly natural gas price forecast for the Colorado Interstate Gas (CIG) trading hub, extending through the planning horizon. In addition to the base case pricing, Siemens also provided high and low gas price projections the planning team used to develop sensitivity cases. The high- and low-price projections reflect changes to the underlying fundamentals of the gas market, such as production volumes, export volumes or changes in consumption. All three gas price projections are shown in Figure 39.

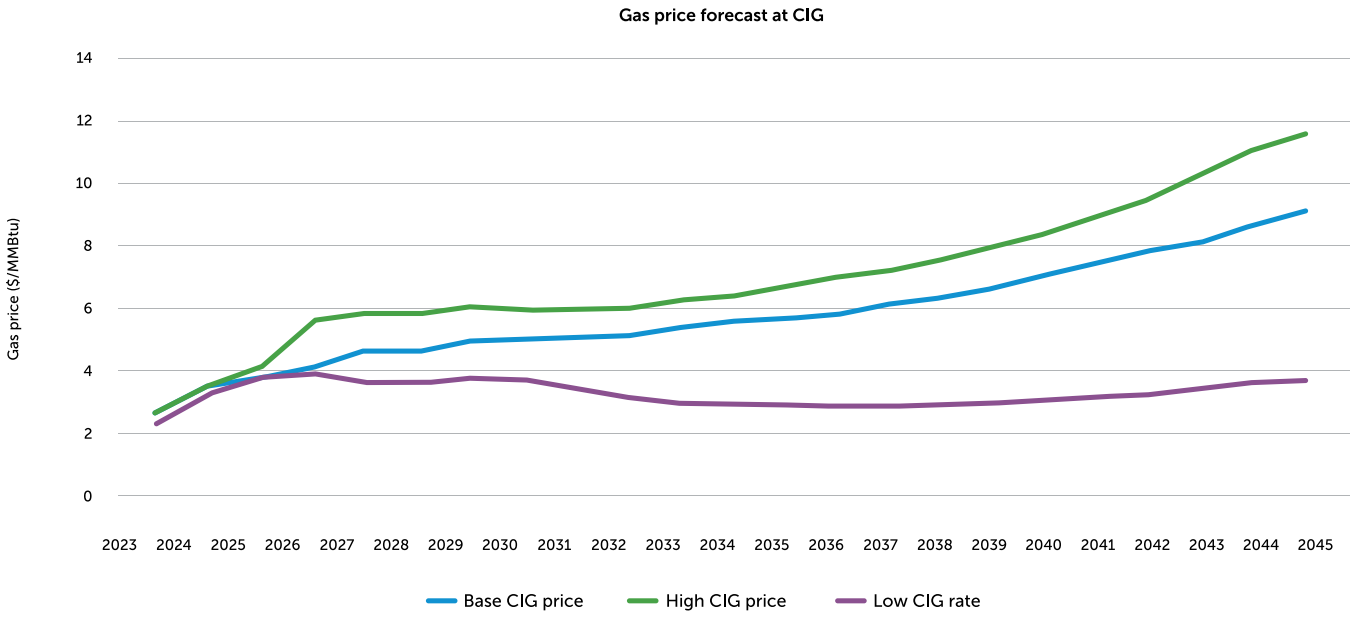


Figure 39. *Gas price forecast at CIG*

In addition to the above gas commodity prices, Platte River also pays transportation for natural gas delivered to the Rawhide site. Charges begin at $1.05/MMBtu for 2024, based on actual expenses, and increase at the assumed inflation rate.

Analysis assumes additional gas-related cost for gas pipeline reservation to improve the reliability of gas supplies after coal retirements. Actual gas supply cost varies depending on consumption levels, but an average cost to firm gas supply ranges from $35/kw-yr to $50/kw-yr for different gas units. These costs begin in 2030 and end in 2040, when the models assume the units switch to 100% green hydrogen. To improve fuel supply reliability, we will analyze options for firming up gas supplies, such as on-site storage or constructing an additional pipeline to the Rawhide plant site.

6.1.2 Green hydrogen prices

Green hydrogen as a noncarbon-emitting fuel for traditional gas turbines has potential in the future, as technological and economical barriers for storing and transporting hydrogen diminish. Based on the recommendations from Black & Veatch, Platte River assumed a 50% blend of hydrogen with natural gas in 2035 and use of 100% hydrogen in 2040. Future hydrogen pricing is uncertain; IRP modeling assumed 2035 hydrogen prices five times the prices of natural gas by 2035, decreasing to three times of natural gas by 2045. Hydrogen prices can be expressed in $/MMBtu or $/kg units. Price projections are shown in Figure 40.

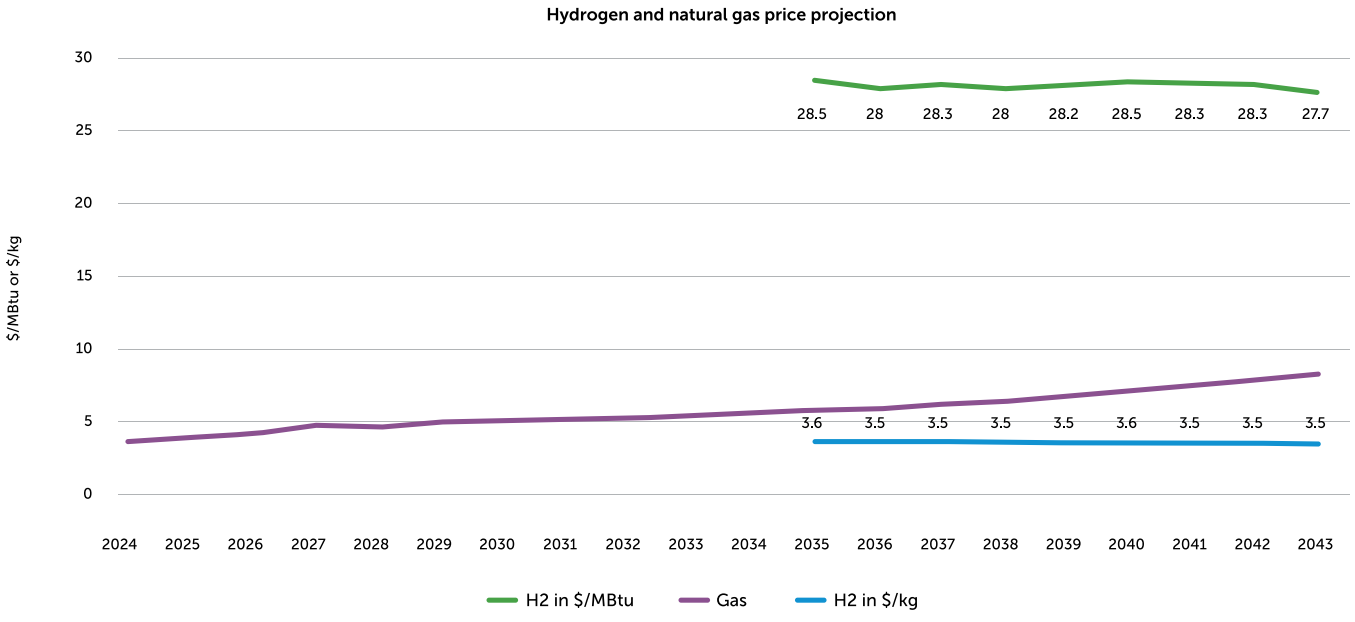


Figure 40. *Hydrogen and natural gas price projection*

6.1.3 Coal prices

Each coal plant in Platte River's portfolio operates with a unique coal supply arrangement. This means that price forecasts for Rawhide Unit 1 and the two Craig units are developed separately, as discussed below.

Rawhide receives coal from the Powder River Basin by rail and its price forecast is largely based on broader market prices. Near-term prices reflect existing contracts and prices that have been locked in with the supplier and near-term coal market assessments and indices. As locked-in quantities with prices tied to market indices decrease over time, the remaining coal is priced at Siemens's forecast for Powder River Basin coal. By 2027, the price forecast is based entirely on the forecasted commodity price from Siemens. The commodity price is adjusted to reflect mine-specific pricing. It includes additional costs for required dust suppressants and taxes passed through by the mine. Transportation expenses, based on the current rail rates projections, are also added to forecast delivered coal price.

The overall Craig coal price forecast is based on price forecasts provided by Trapper Mine, which is adjacent to the Craig plant. Platte River has a partial ownership interest in Trapper Mine and coal costs are determined on a "cash cost" basis, with no transportation costs incurred. Figure 41 illustrates the delivered coal prices for Platte River coal plants.

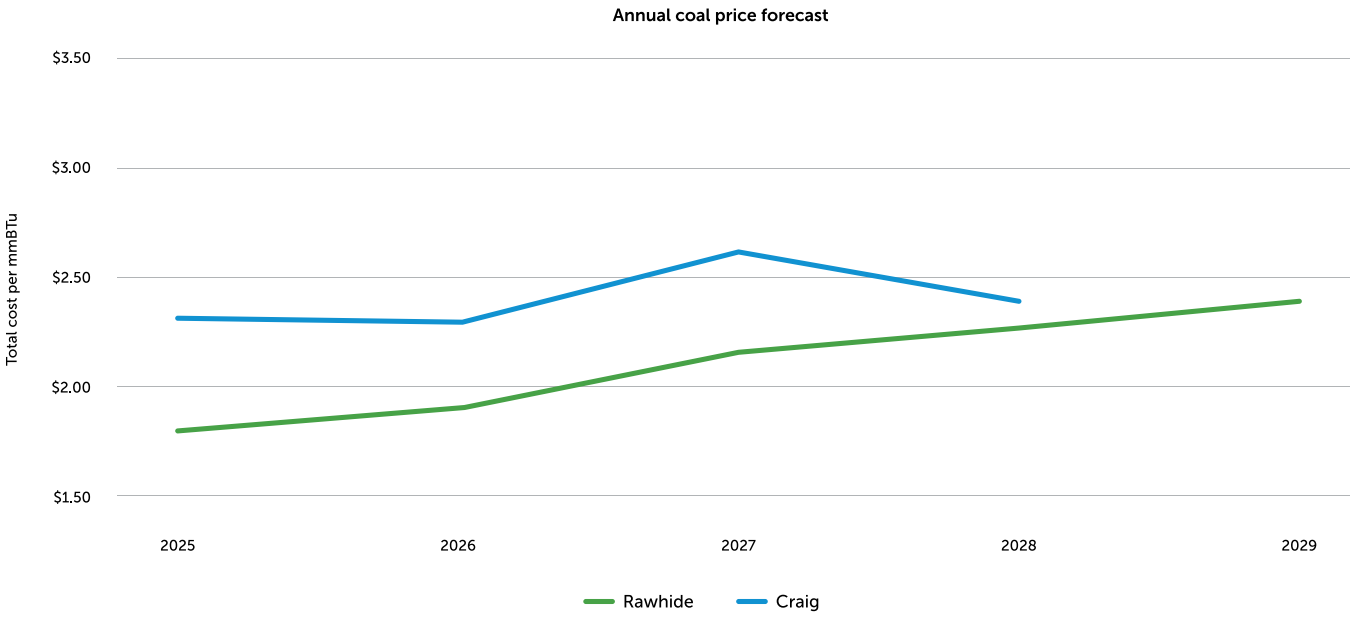


Figure 41. *Annual coal price forecast*

6.1.4 Regional power prices

Platte River's resources are dispatched in real time with resources from other utilities in the WEIS market to maximize economic exchange of power across the market. In addition to the real-time market, Platte River transacts with neighboring utilities bilaterally, selling excess power and buying power when needed. To simulate these bilateral transactions with neighboring utilities, resource planning models a regional market where Platte River can buy or sell when economical. Siemens has provided hourly future prices for Colorado area and these hourly prices are used in our simulations. During portfolio simulations, the Platte River system was allowed to buy power when the regional market price is lower than Platte River's marginal cost of production and allowed Platte River to sell excess power when the market prices are higher than its marginal cost. Net revenues from market transactions reduce the overall cost of providing power to Platte River's owner communities.

With more renewable resources on the regional grid, renewable energy becomes a bigger driver of power prices. Siemens predicts that average annual power prices will remain relatively stable over the 20-year planning horizon. However, daytime prices (labeled as "on-peak solar" prices in Figure 42) will decline as more solar generation is added.

Figure 42 shows our current forecast for on-peak and off-peak power prices, including solar and non-solar hours. The model defines on-peak hours as Monday-Saturday from 6 a.m. to 10 p.m., with on-peak solar 8 a.m. to 5 p.m. every day and on-peak non-solar 5 p.m. to 10 p.m. Monday-Saturday. Off peak hours are 11 p.m. to 5 a.m. Monday-Saturday and all day Sunday. As shown in Figure 42, on-peak non-solar prices (representing the evening hours) stay the highest and on-peak solar, which reflect the day and time when solar is plentiful, are the lowest prices.

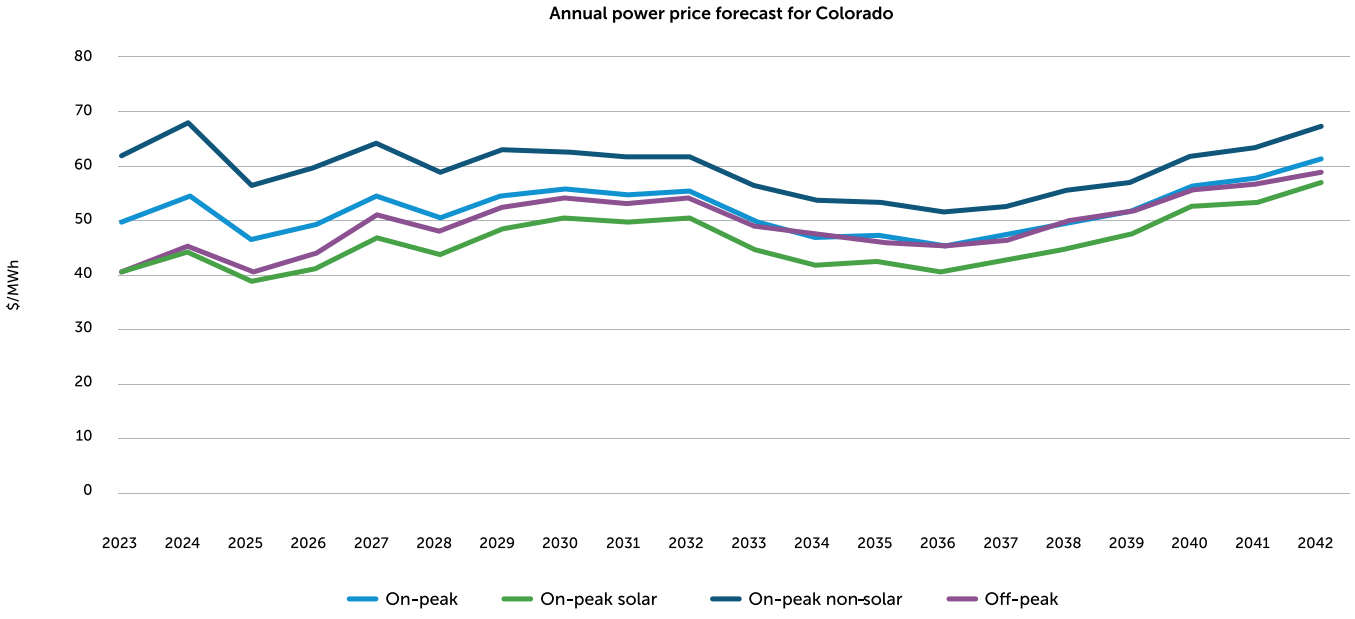


Figure 42. *Annual power price forecast for Colorado*

For the 2024 IRP, Siemens provided an hourly price forecast and the renewable energy patterns used in their price forecasting models, which helped correlate relationships between market prices and energy production from the intermittent wind and solar resources. Siemens also provided the natural gas and emission prices forecasts, which were appropriately correlated to an hourly level in the IRP assumptions to ensure internal consistency among various projections.

6.1.5 Carbon taxes embedded in projected energy prices

Siemens supplied a carbon price (tax) forecast based on its expectations concerning public policy discussions and potential legislation. A carbon tax will discourage carbon emissions.

Platte River also evaluated portfolio outcomes using a social cost of carbon. The social cost of carbon simulates total direct and indirect (such as healthcare or extreme weather events) cost to the society from continued CO2 emissions. The social cost of carbon projection was based on the guidance of the Colorado Air Quality Control Commission, which valued the social cost of carbon at $68 per short ton in 2020 with an escalation rate of 2.5%, as shown in Figure 43.

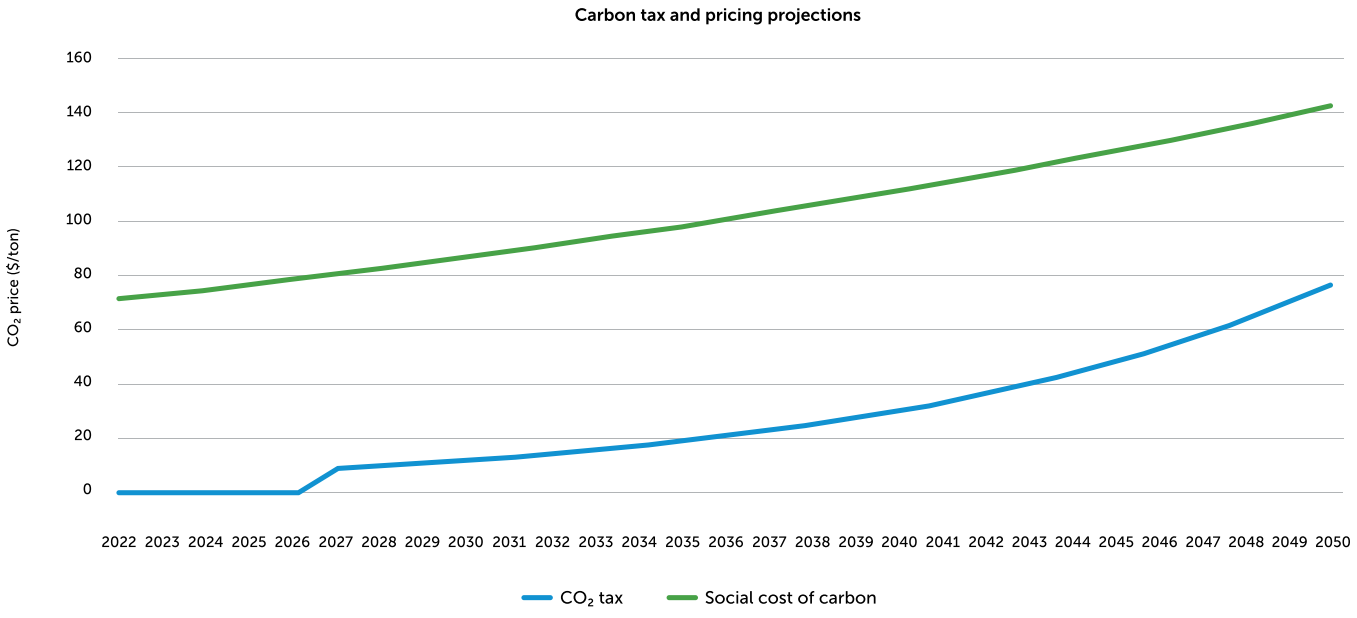


Figure 43. *Carbon tax and pricing projections*

6.2 Regional import/export limits

Platte River joined the WEIS market in April 2023, where Platte River's generation resources are jointly dispatched along with generation resources of other market participants to minimize dispatch costs for all market participants. When it joins SPP RTO West, Platte River will serve its load with a combination of owned resources and lower-cost resources from other market participants, implying real-time power sales and purchases with other RTO members. In addition, Platte River will continue bilateral transactions with regional entities, marketing excess energy through short- and long-term transactions. For IRP modeling, analysts assumed purchases or sales up to 150 MW in any hour. The 150 MW import/export limit means that market transaction volume remains realistic and that Platte River builds enough reliable energy generation to meet customers' needs and planning reserve margin requirements.

6.3 Supply-side generation resources

This section discusses all power generation resources Platte River considered to meet its customers' future electricity needs, beginning with our existing resources followed by committed resources. We then discuss additional future resources and the screening process to select candidate resources. A detailed discussion follows concerning the resources (both renewable and traditional) that Platte River is evaluating for future investment.

6.3.1 Platte River's existing resources

Platte River's existing supply-side resources consist of power plants, PPAs and community solar generation facilities. Distributed and community-owned solar were modeled as supply-side resources even though they may have unique contracts with retail load or with an owner community's distribution utility. For modeling purposes, they function as resources that serve community load. Tables 10-15 list Platte River's existing resources.

Coal generation facilities	Nameplate capacity (MW)	Effective capacity (MW)	Commercial operation	Nominal retirement / contract expiration
Rawhide Unit 1	280	280	1984	2029
Craig Unit 1	77	77	1980	2025
Craig Unit 2	74	74	1979	2028

Table 10. *Platte River's existing coal resources*

Natural gas (simple-cycle CTs) generation facilities	Nameplate capacity (MW)	Effective capacity (MW)	Commercial operation
Rawhide Unit A	65	65	2002
Rawhide Unit B	65	65	2002
Rawhide Unit C	65	65	2002
Rawhide Unit D	65	65	2004
Rawhide Unit F	128	128	2008

Table 11. *Platte River's existing natural gas resources*

Contracted wind resources	Nameplate capacity (MW)	Effective capacity (MW)	Commercial operation
Medicine Bow	6	1	1998
Silver Sage[11]	12	2	2009
Spring Canyon I[12]	32	5	2014
Spring Canyon II	28	6	2014
Roundhouse	225	39	2020

Table 12. *Platte River's contracted wind resources*

Contracted hydropower[13] resources	Nameplate capacity (MW)	Effective capacity (MW)	Commercial operation
Loveland Area Project	30	30	1973
Colorado River Storage Project	60	48	1973

Table 13. *Platte River's contracted hydropower resources*

Contracted solar resources	Nameplate capacity (MW)	Effective capacity (MW)	Commercial operation
Commercial solar power purchase program	4	2	Approved 2013
Fort Collins community solar	1	0.4	2015
Foothills Solar (Platte River share)	0.5	0.2	2016
Rawhide Flats	30	17	2016
Rawhide Prairie	22	12	2020

Table 14. *Platte River's contracted solar resources*

Contracted storage resources	Nameplate capacity (MW)	Effective capacity (MW)	Commercial operation
Rawhide Prairie Battery	1 MW x 2 hours	1	2020

Table 15. *Platte River's contracted storage resources*

[11] Silver Sage wind has been sold through 2029, when its PPA with Platte River expires. It does not return as a resource.

[12] Both Spring Canyon resources were sold in 2020 through 2030. They will return to Platte River in June 2030 and serve Platte River customers for the remaining term of their contract (through 2039).

[13] Estimated effective capacity due to persistent drought conditions throughout the West.

6.3.2 Committed or expected resources

This category includes resources for which either a final contract has been signed or negotiations are ongoing. These resources are treated like existing resources. These resources are included in modeling as assumed available and not subject to change through the optimization and resource selection process. These resources are shown in Table 16.

Committed resources	Nameplate capacity (MW)	Effective capacity (MW)	Commercial operation	Current status
Solar				
Black Hollow	150	31	2025	PPA signed
New solar	150	24	2026	Negotiations ongoing
Storage				
Community battery	25 MW x 4 hours	18	2026	Negotiations ongoing

Table 16. *Committed resources*

6.3.3 Future candidate resources

Platte River selected future candidate generation resources by reviewing data from credible public sources, its consultants and its own market intelligence as detailed below. This section provides an overview of data sources, selection process and details of the selected resources.

6.3.3.1 U.S. Energy Information Administration

The EIA publishes cost and performance of new generation every year in its annual energy outlook report. The EIA report[14] is comprehensive and covers state of the art in traditional, low-carbon and renewable power generation technologies. We selected the following technologies from this report for further evaluation:

- Onshore wind
- Solar photovoltaic
- Battery storage
- Aeroderivative combustion turbine
- Reciprocating internal combustion engine
- Carbon sequestration
- Modular nuclear
- Geothermal

Planning staff screened out the following technologies from this report, as they are not suitable for Platte River's future power supply portfolio.

- Coal with or without carbon sequestration
- Combined cycle with or without carbon sequestration
- Large nuclear
- Offshore wind
- Biomass
- Solar thermal
- Conventional hydro
- Fuel cells

6.3.3.2 Black & Veatch consulting support

In addition to the resources considered from the EIA report, Platte River engaged Black & Veatch[15] to assess the landscape of low- and no-carbon fuels, energy storage and dispatchable power generation technologies. The Black & Veatch report assessed the availability of these technologies for 2028 commercial operation. For technologies not available for 2028, they estimated their future costs and commercial availability in the next decade. Black & Veatch reviewed the following options:

- **Biofuels.** The study concluded biofuels for power generation are not a viable option at Rawhide due to limited fuel availability and significant modifications required in the equipment to burn this fuel. Biofuels are better suited for transportation applications, rather than large power generation.

- **Hydrogen** – both green and blue. Green hydrogen is produced by an electrolyzer using renewable electricity, while blue hydrogen is produced from natural gas and the CO2 produced in the process is sequestered and stored in the ground. Hydrogen can be used as fuel in traditional power generation machines like CTs with some modifications. But there are significant technoeconomic challenges to store and transport hydrogen. The study concluded that green hydrogen could be a viable option for Platte River starting in the middle of the next decade.

[14] https://www.eia.gov/outlooks/aeo/assumptions/pdf/elec_cost_perf.pdf

[15] Results from the generation technology screening by Black & Veatch are accessible on Platte River's IRP microsite at prpa.org/2024irp/information.

- **Renewable natural gas.** Renewable natural gas is produced mostly at landfill or biowaste locations. The study concluded that renewable natural gas for power generation at the Rawhide site is not a viable option due to limited fuel availability. This fuel is better suited for small power generation at or near locations where the fuel is produced, such as landfill or wastewater treatment sites. Another possible use of renewable natural gas is for transportation, like the City of Longmont using renewable natural gas from its wastewater facility in the waste services truck fleet, displacing the use of diesel fuel. In some cases, renewable natural gas can be refined enough to meet the pipeline quality natural gas standard and can be pumped back into the gas network.

- **Ammonia.** Since transporting hydrogen over long distances is technologically and economically challenging (because hydrogen is a very light-weight molecule), industry is considering converting hydrogen into ammonia and then transporting it. At the destination, ammonia can be used directly in power generation or converted back to hydrogen and then used. The study concluded ammonia for power generation is not a viable option. It is better suited for transportation applications, rather than large-scale power generation.

- **Carbon capture and sequestration.** Carbon capture and sequestration technology was considered for removing CO2 from the existing combustion turbine units at the Rawhide site. The study concluded carbon capture and sequestration is not a viable option at Rawhide due to high cost of CO2 removal in peaking units (like those at Platte River, where combustion turbines are expected to run less than 20% of the time), and lack of known places to sequester CO2. Carbon capture and sequestration technology is a better option for baseload applications, where the generation source is running continuously and where the large capital cost can be spread over numerous tons of removed CO2. Additionally, carbon capture and sequestration technology is in the early commercial stages of development, with few proven and successful applications for power generation.

- **Long duration energy storage.** The study concluded that long-duration energy storage is an emerging technology, but not ready for commercial operation in 2028. This technology has potential and may become commercially available by the middle of the next decade. Platte River decided to plan for a 10 MW pilot long-duration energy storage project by 2030 and assume the technology would be available for commercial applications by 2035.

- **Flexible and low CO2 emitting thermal power generation.** In addition to the low- or no carbon emitting power generation options discussed above, the study reviewed various traditional combustion turbine and reciprocating internal combustion engine technologies that are flexible, reliable, efficient and hydrogen-capable. Three key future dispatchable technology requirements will be reliability, flexibility, and the ability to provide power for at least one week during dark calms. Because low or no-carbon options were not commercially available, the study recommended using gas-fired combustion turbines or reciprocating

internal combustion engines for commercial operation in 2028 and progressively converting to green hydrogen when it is economically available in large quantities. Combustion turbine and reciprocating internal combustion engine vendors claim that these machines will be capable of burning about 30% hydrogen by 2028.

6.3.3.3 Platte River's own market intelligence

Plate River's portfolio integration team monitors markets and collects information informally and formally through requests for information and requests for proposals. This engagement informs Platte River of the latest technology and pricing trends in the area. EIA, Annual Technology Book (ATB) or consultants can provide market trends and average prices, but the real prices for our area are available only through engagement with developers and vendors. Platte River conducted a solar and storage RFP in 2022 and started a wind RFP in 2023. These market interactions were valuable for collecting information about the projects being developed in our region—their costs, locations, schedules and technologies. This information was used to input costs of renewable and storage technologies in IRP modeling.

6.3.3.4 NREL's Annual Technology Book

NREL provides cost, efficiency and technology improvement trends of renewable and storage technologies in the ATB every year. We used the data in the 2022 ATB for this IRP, as it was the latest available in the spring of 2023 when staff finalized assumptions.

After a detailed review of all the sources mentioned above and internal deliberations, Platte River decided the following:

- For wind, solar and four-hour storage costs, we used our own market intelligence data for early year prices where data was available from multiple vendors.
- After the first three years, we used cost escalation and efficiency improvement rates proposed by the ATB.
- Actual cost data used for each technology is shown in the following sections.

For dispatchable resources, Platte River relied on the recommendations of Black & Veatch. Platte River decided the best option is to use highly flexible, state-of-the-art, hydrogen-capable aeroderivative combustion turbine technology. These machines will initially use natural gas fuel and by 2035 may start using 50% green hydrogen blend and by 2040 may use 100% green hydrogen. The process of selecting aeroderivative technology is discussed in section 6.3.7.

6.3.4 New wind resources

While wind resource availability within Platte River's service territory is limited, wind is abundant to the north and the southeast. Most likely, our future wind will come from southeast Wyoming or eastern Colorado. We have assumed that the southeast Wyoming wind will be delivered to Platte River through existing transmission capacity that will become available after retirement of Craig coal generation.

Eastern Colorado wind would be delivered through a neighboring transmission system at a cost of $6/MWh in 2023 and escalating with inflation. Because the existing transmission infrastructure in southeast Wyoming is limited, only 200 MW of wind is expected to be procured without incremental transmission cost. Any future wind will include a transmission charge or new transmission infrastructure at an assumed cost of $6/MWh.

New wind resources are assumed to be procured under PPAs for 100 to 200 MW blocks. PPA payments compensate the developer or the owner for capital costs (depreciation and returns), financing costs, interest during construction, taxes (sales, property, and income) and ongoing operating and maintenance costs. PPA prices for wind are based on recent quotes from project developers in the region. We assumed future wind prices will escalate based on the 2022 ATB future wind cost curves.

Southeast Wyoming wind is assumed to have an average annual capacity factor of 42.5%, while the eastern Colorado wind was modeled with a 45% capacity factor.

Wind projects (existing or new) carry ancillary service charges through 2025. Beyond 2025, we assume those costs cease with entry into a regional market. The combined cost of wind ancillary services in 2024 were modeled at $1.24/kw-mo.

Figure 44 shows wind costs for the two locations along with solar costs. As mentioned earlier, PPA prices are generally fixed for their terms (typically 20-30 years). Figure 44 assumes that for 2026, the southeast Wyoming wind PPA price will be fixed at $35/MWh for the PPA term, while for the wind PPA signed in 2030, it will cost $33.65/MWh for the life of the project.

6.3.5 New solar resources

New solar resources were considered as 50 MW block sizes priced at a 30-year levelized PPA payment, including transmission interconnection costs. Solar generation is assumed to have an annual capacity factor of 28%. Platte River received solar price data based on recent RFPs and negotiations with developers. These prices were escalated with NREL's 2022 ATB solar cost projections.

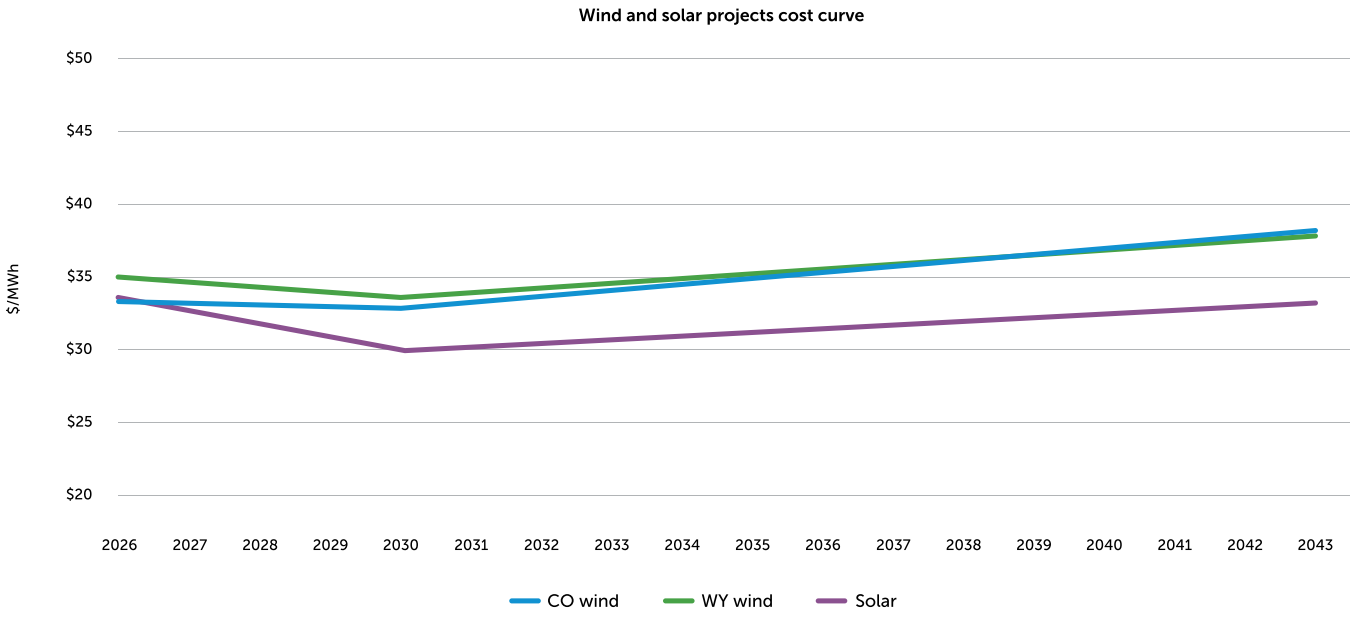


Figure 44. *Wind and solar projects cost curve*

Platte River assumed that new solar projects will be built within the existing Platte River transmission footprint. Consequently, no new transmission capital costs or third-party wheeling costs were assumed for solar generation. Solar ancillary service costs in 2024 were assumed at $0.09/kw-mo.

6.3.6 New storage resources

Energy storage is the keystone in a deeply decarbonized power supply portfolio. A 100% renewable power supply portfolio using wind and solar as the main source of energy will need energy storage from a few seconds to several days to complement supply intermittency. Platte River considered a variety of different commercially available battery storage technology options, including lithium-ion batteries for four-hour storage duration, flow batteries for 10-hour storage duration and long-duration energy storage batteries for 100-hour storage duration. These battery types will provide different services to support the grid while complementing renewable intermittency.

Four-hour lithium-ion battery technology is mature and commercially available. We assumed 200 MWh of storage per 50-MW four-hour battery, which would provide up to four hours of discharge capacity at a rate of 50 MW per hour. Four-hour batteries were assumed to have an 85% round trip storage efficiency. The economic life of a four-hour battery was modeled to be 20 years. Like wind and solar, 2024 prices for four-hour battery storage were based on the recent RFP and vendor negotiations. Future prices escalate based on the 2022 ATB. See the cost projections in Figure 45.

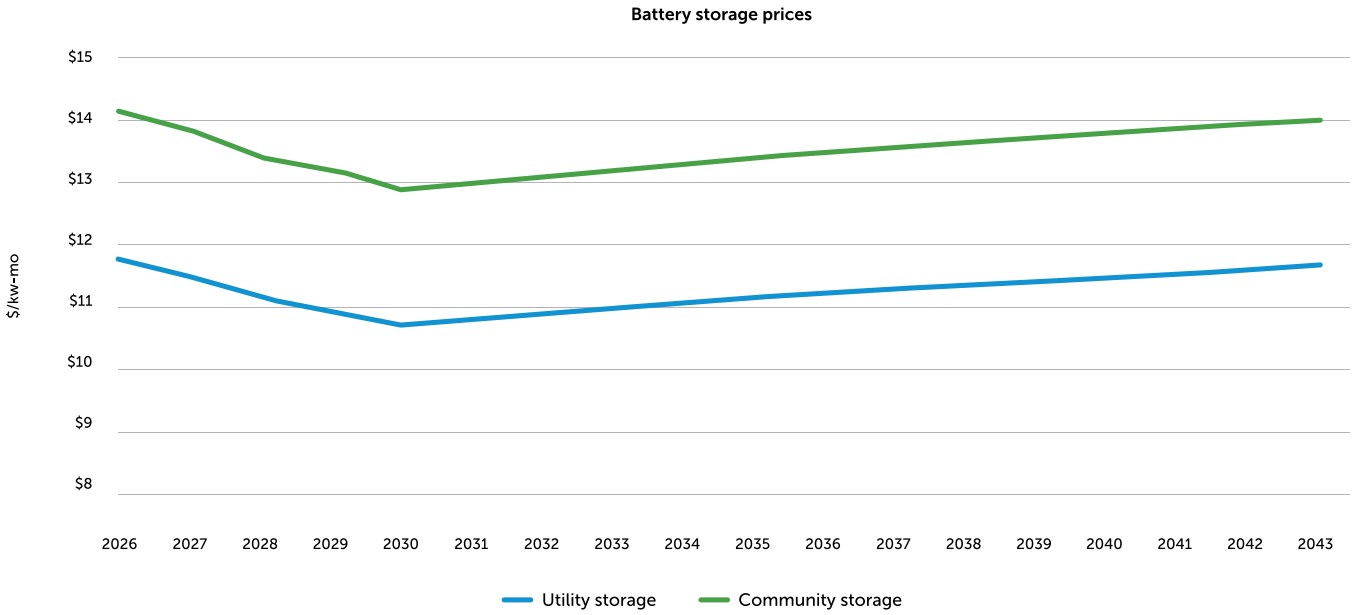


Figure 45. *Battery storage prices*

Ten-hour flow batteries are an emerging technology with no existing commercial installations as of 2023. We worked with a vendor to get cost, efficiency, and performance details. Based on the data provided by the vendor, this technology was not found to be economical during our early technology screening and minimal cost portfolio development process. Therefore, this technology was not considered as a resource in the IRP. However, this technology has potential to become part of the future power supply portfolio. As the technology matures, Platte River will consider it.

Long-duration energy storage is critical for supplying power during extended dark calm periods. Like flow batteries, this technology is also under development with no existing commercial installations as of 2023. Platte River analyzed the cost, efficiency, and performance details of long-duration energy storage. When fully developed and commercialized, long-duration energy storage will reduce the need for fossil generation to provide backup power and reliability in a renewable portfolio. Platte River plans to integrate a 10 MW pilot unit before 2030. For IRP modeling, we assumed that the technology will be commercially available by 2035. The current capital cost of this technology is high, and the round-trip efficiency is low. We assumed cost reduction and performance improvements over time as the technology matures and finds commercial applications.

6.3.7 New dispatchable thermal generation resources

As mentioned earlier, after a thorough review of all the options for no- or low-carbon fuels, and for dispatchable generation technologies, Black & Veatch recommended Platte River use natural gas-fired generation for 2028 commercial operation and then convert to green hydrogen fuel when it is commercially available. Platte River and Black & Veatch looked at 50+ options and screened down to the seven listed in Table 17 for detailed assessment.

Characteristic	Unit	LM2500	LM600	LMS100	RICE	7F CC conver-sion	LM600 CC	SGT800
Unit size	MW	28	40	90	17	17-116	31-44	55
Heart rate	btu/kWh	9,875	9,649	8,820	8,510	6,646	7,087	9,707
Cost per MW	$M/MW	$1.8	$1.7	$1.2	$1.7	$2.2	$2.3	$1.4

Table 17. *Screened dispatchable technologies*

LM2500, LM6000 and LMS100 are aeroderivative CTs manufactured by General Electric. RICE is reciprocating internal combustion engine. The next two were combined cycle options; converting the existing 7F CT at Rawhide station or install 4 LM6000 CTs with combined cycles. Finally, SGT800 is a combination of frame and aeroderivative technologies manufactured by Siemens.

After analyzing the levelized cost of energy and reviewing operational characteristics of the seven technologies, a smaller group of four featured in Table 18 was selected for more detailed assessment. These four technologies were further analyzed in detail for characteristics like reliability, emissions, economic value, operational flexibility, fuel versatility, constructability and market performance. During this detailed evaluation, higher weights were assigned to the factors aligned with Platte River's three pillars of reliability, environmental responsibility and financial sustainability. This analysis concluded that aeroderivative technology was the best option for Platte River. The LM6000 technology was selected as the presumed technology for inclusion in the supply portfolio.

Qualification	Weight	Option 1	Option 2	Option 3	Option 4
Reliability	30%	1.52	2.52	2.7	1.51
Emissions	25%	0.7	2.41	2.34	1.69
Costs	20%	1.55	1.47	1.55	2
Operational flexibility	10%	0.9	0.91	0.88	0.8
Fuel versatility	5%	0.05	0.36	0.36	0.42
Constructability	5%	0.45	0.45	0.45	0.35
Market performance	5%	0.4	0.5	0.45	0.45
Total weighted score	**100%**	**5.57**	**8.62**	**8.72**	**7.21**

Table 18. *Results of detailed screening of four selected technologies*

07 IRP design

7.1 Studies

The following studies support this IRP. All studies are available on the IRP microsite.

- PRM and ELCC study by Astrape Consulting
- Beneficial electrification forecast by Apex Analytics
- Distributed energy resources forecast and potential study by Dunsky
- Extreme weather events and dark calm analysis by ACES
- Independent review of dispatchable capacity needs by Black & Veatch
- Generation technology screening by Black & Veatch

Additionally, this IRP uses fundamental market analysis of supply and demand in the region provided by Siemens, and a locational marginal pricing assessment by ACES.

7.2 Objectives

The objective of this IRP is to continue Platte River's journey toward achieving the goals of the RDP by developing a roadmap to meet the owner communities' needs for reliable, environmentally responsible and financially sustainable energy and services using a diverse power supply portfolio.

7.3 Planning for a reliable future power supply

Power supply reliability is a key responsibility of a utility. It is a foundational pillar for Platte River's planning and operations. Platte River plans to join a full organized energy market in 2026, which will take over transmission planning and some operational responsibilities. In a market, a load-serving entity like Platte River is required to bring enough resources to reliably serve its load according to the reliability criteria enacted by the market operator. Markets allow a wider access to improve economics and reliability under varying weather and operating conditions, but they do so by relying on the resources contributed by each market participant. This chapter covers reliability modeling in the IRP and the development of different power supply portfolios to cover a wide range of future possibilities.

7.3.1 Power supply reliability

As society's dependence on electricity increases, power supply reliability is becoming more critical. Electric reliability is not only the foundation for commerce; our security and safety depend on it. This critical dependence became tragically clear when Texas power outages during Winter Storm Uri caused 246[16] deaths and billions of dollars in economic losses.

Power supply reliability is the ability of a power system to keep the lights on under changing supply and demand conditions. Electric utilities must plan, design, construct and operate an electric supply system for reliability of supply.

There are a few terms used under the broad umbrella of reliability:

- Adequacy is a measure of the ability of a power system to meet the electric power and energy requirements of its customers within acceptable technical limits, considering scheduled and unscheduled outages of system components.
- Security is the ability of the power system to withstand disturbances.

[16] Texas winter storm: 246 Texans' deaths classified as winter-storm related (kxan.com).

[17] https://www.energy.gov/articles/economic-benefits-increasing-electric-grid-resilience-weather-outages

- Resilience is the ability to quickly adapt and recover from a disruption, with minimal impact.

Historically, threats to power supply reliability included equipment failure (at the distribution, transmission, or generation level) or extreme weather like hurricanes, floods, snowstorms and heat storms. More than 90% of the power supply interruptions or reliability events can be attributed to breakdowns in the distribution system.[17]

Distribution system interruptions are typically localized and affect a small number of customers. Reliability events that stem from interruptions on the generation or transmission system, or lack of generation, are broader reaching and potentially more consequential. With increased reliance on wind and solar generation in the future, an additional threat to reliability will be low or no production from these intermittent resources for extended periods.

In our IRP process, Platte River focuses on reliable, environmentally responsible and lowest reasonable cost power supply portfolios. Some of the major variables that drive power supply reliability in our planning process are:

- Occasional generation equipment failures
- Load forecast uncertainty
- Variability of hourly wind and solar generation patterns
- Occasional extreme weather (such as heat or cold waves)
- Extended periods of low or no renewable generation

After an extensive review of hourly generation profiles of solar and wind, we found that there are certain times when there is very little or no renewable generation for extended periods. We call these incidents dark calms. We have found that dark calm events occur frequently and can last from a day to as long as seven days.

While our definitions of reliability and related concepts are general, over the years the power industry has developed specific metrics and methods to plan for a reliable supply portfolio as discussed in the next section. A starting point for developing a reliable power supply is a resource adequacy study. This study simulates a future power supply portfolio under varying conditions of power supply and power demand to assess its reliability.

7.3.2 Planning for a reliable future portfolio

7.3.2.1 Reliability metrics for planning

The North American Electric Reliability Corporation, the regulatory authority whose mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid, defines requirements for resource adequacy in Standard BAL-502-RFC-02.[18] This standard requires utilities to "calculate a planning reserve margin that will result in the sum of the probabilities for loss of load for the integrated peak hour for all days of each planning year analyzed being equal to 0.1." This metric is also referred to as Loss of Load Expectation (LOLE) of 0.1 per year or LOLE of one day in 10 years, or sometimes, as "One Day in Ten Years" (ODTY). This metric has been widely used in planning studies since the early days of modern power systems.[19]

This metric has traditionally guided investment in generation to provide reliability accepted as the optimal target. Historically, ODTY or 0.1 day LOLE per year has required utilities to maintain a 10-15% PRM. PRM is defined as the percent additional firm capacity relative to the peak demand in a future year. Specifically,

$$\text{PRM} = \frac{\text{Firm capacity - peak demand}}{\text{Peak demand}}$$

Historically, PRM covered planned or unplanned outages (equipment breakdowns) and load forecast error due to weather and economic growth uncertainty. Following the retirement of dispatchable coal generation (which provides

firm capacity) over the past decade, and with the introduction of intermittent renewable generation resources, the structure of power supply portfolios is rapidly changing.

LOLE of 0.1 day per year is still the dominant metric in the power industry, but some alternatives are being proposed and debated.[20] The main criticism of 0.1 day LOLE per year metric is that this probabilistic calculation does not adequately measure the depth (how much power was lost, or how many customers lost power), breadth (how long power was lost) and the frequency (how often power was lost).

In a recent report,[21] EPRI summarized the existing and proposed metrics, arguing that a single metric such as ODTY may conceal some risks and may not be able to sufficiently capture

the future challenges to the power grid from:

- Rapid decarbonization of power supply with the retirement of dispatchable resources and adoption of intermittent renewables.
- Adoption of electrification in transportation and heating.
- Adoption of DERs with wider customer involvement.
- Climate change and extreme weather events.

With the introduction of renewable generation, the concept of planning for the "Peak Hour" of the year is giving way to planning for every hour in the year. The hour when the system experiences peak demand is less important than the load net of renewables. For example, Figure 46 from New York ISO[22] shows that typically they experience peak demand between 3-4 p.m. in July, but, due to solar generation, the net peak demand is lower and shifts to 5-6 p.m.

[18] https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-502-RFC-02.pdf

[19] https://www.astrape.com/wp-content/uploads/2024/01/EISPC_The_Economic_Ramifications_of_Resource_Adequacy_White_Paper.pdf

[20] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/ra_t3b2_workshop-1_presentation-telos-and-gridlab.pdf

[21] https://www.epri.com/research/products/000000003002023230

[22] https://www.nyiso.com/-/shaving-peaks-with-the-sun

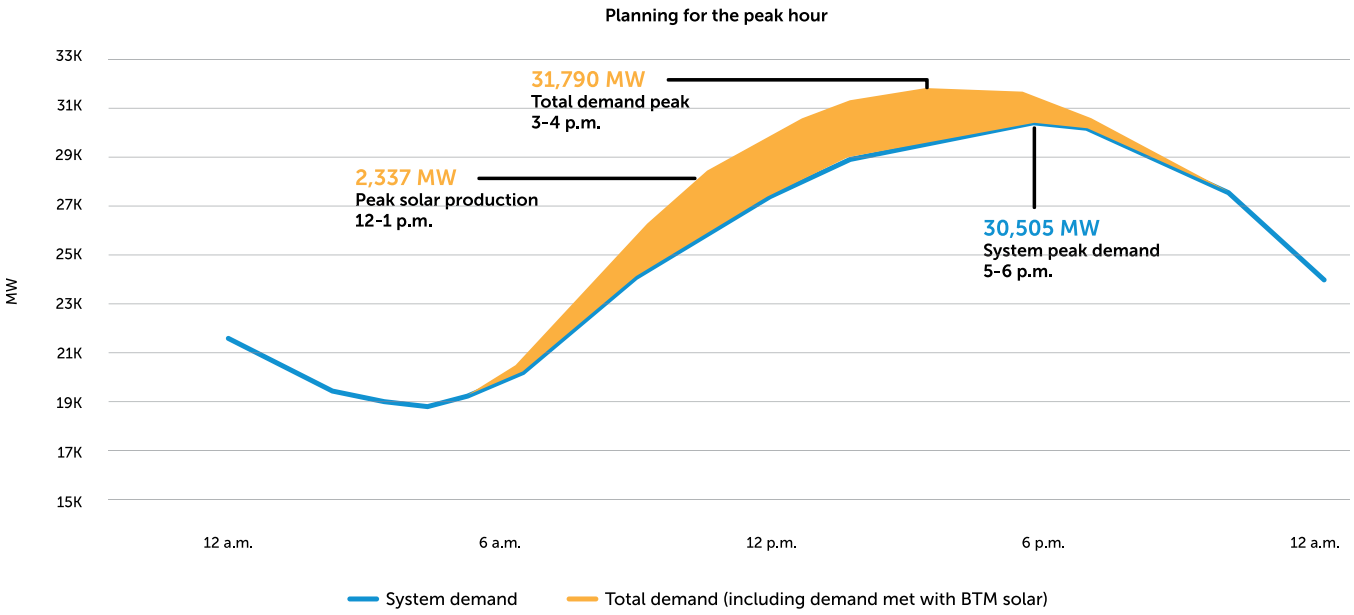


Figure 46. *Planning for the peak hour*

Other parts of the country experience similar phenomena. Wind generation may shift the net peak demand to different hours. In fact, the Western Electricity Coordination Council (WECC), the entity responsible for reliability of the electric grid in 13 western states (including Colorado), is proposing to estimate resource adequacy for every hour, targeting an hourly LOLE of 0.002%.[23]

7.3.2.2 Platte River PRM for future planning

For the 2020 IRP, Platte River used a 15% PRM as its reliability metric. With the changing portfolio mix in the region[24] and with the backdrop of ongoing discussions in the industry, we engaged Astrape Consulting to perform a resource adequacy[25] study for this 2024 IRP. This study computed PRM and ELCC[26] of intermittent renewable resources, small amounts of energy battery storage and DERs. The study focused on the year 2030 and modeled the Platte River supply portfolio, along with other utilities in Colorado. The study assumed these utilities will develop the power supply portfolios projected in their respective IRPs and will be part of a functioning market. The study concluded that all Colorado utilities, including Platte River, would need a PRM of 19.9%. This value, though higher

[23] https://www.wecc.org/_layouts/15/WopiFrame.aspx?sourcedoc=/Reliability/2022%20Western%20Assessment%20of%20Resource%20Adequacy.pdf&action=default

[24] Platte River has filed a voluntary clean energy plan committing to reduce its 2030 CO2 emissions by at least 80% from 2005 levels.

[25] https://www.prpa.org/wp-content/uploads/2023/11/2024IRP-PRM-and-ELCC-study-by-Astrape.pdf

[26] ELCC of a resource is the measurement of that resource's ability to produce energy at the time of peak demand.

[27] https://www.wecc.org/Administrative/2023%20Western%20Assessment%20of%20Resource%20Adequacy.pdf

than the 2020 IRP PRM of 15%, aligns with the WECC-recommended Planning Reserve Margin Index or Variability Margin Index in its 2023 Western Assessment of Resource Adequacy[27] report. Power markets like the Midcontinent Independent System Operator (MISO) and SPP are also looking at higher PRMs than previously recommended due to coal retirements and more intermittent energy integration.

Astrape's proposed PRM of 19.9% for 2030 incorporates its analysis of Colorado, utilities including Xcel Colorado, Colorado Spring Utilities and Black Hills Colorado, using their modeling platform Strategic Energy & Valuation Model, which is also used by major U.S. utilities and several regional power pools. Astrape modeled major uncertainties like weather by using 42 years of historical data for hourly wind, solar and load shapes, three to five days of dark calms, five scenarios of future load forecast error and 300 scenarios of generation availability, for a total of 63,000 simulation scenarios for each hour of the year 2030. This comprehensive analysis produced the relationship between LOLE and PRM as shown in Figure 47.

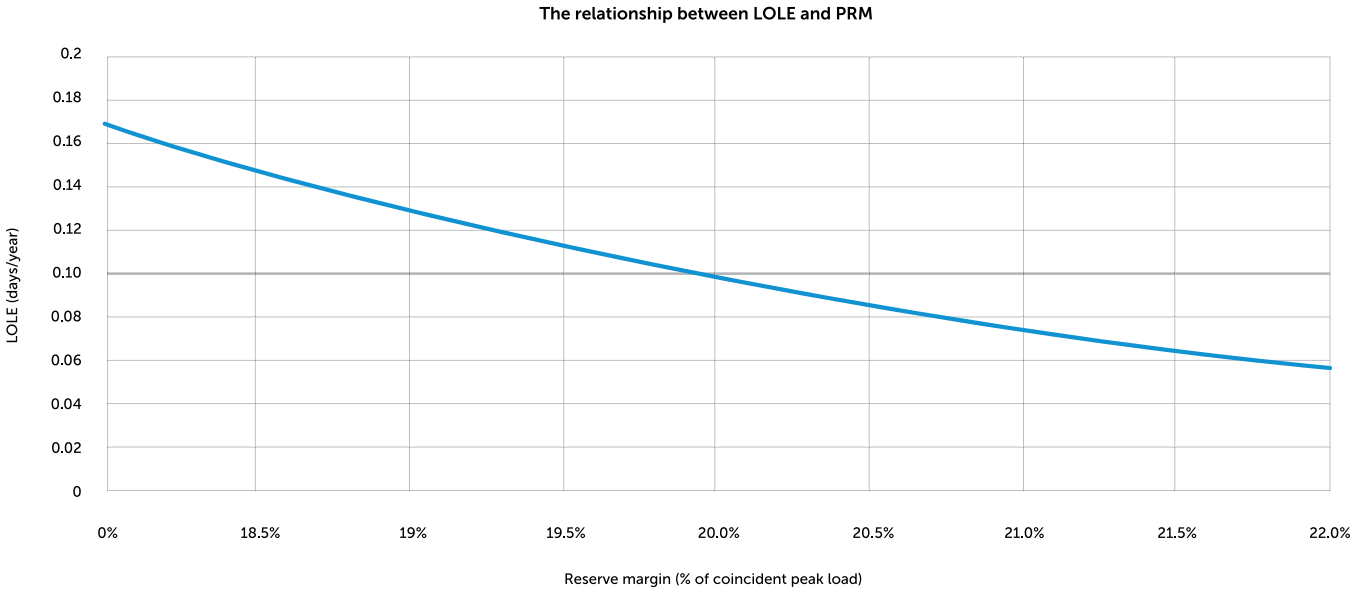


Figure 47. *The relationship between LOLE and PRM*

At 0.1 day LOLE per year, the PRM is 19.9%. If we were to build a more reliable system with a LOLE of 0.06, or one outage every 16 years, we will need a PRM of 21.8%. On the other hand, a LOLE of 0.16, with an expected outage every six years, would require a PRM of 18.4%. Essentially, the more spare capacity we have, the less likely we are to face a supply shortage or LOLE.

As mentioned earlier, EPRI recommends not relying on one metric. Utilities and other entities are considering many metrics. In addition to the PRM, we used Loss of Load Hours (LOLH) in our IRP modeling. LOLH measures the average duration of outages. We used LOLH 0.2 during reliability testing of our portfolios.

7.3.2.3 ELCC values for renewables and limited energy resources

The ELCC of a renewable or energy-limited resource measures its expected contribution to peak demand. For example, 100 MW from a coal or gas fired plant can provide 100 MW at the time of peak. When running at full load, it will reduce the peak load by 100 MW. The ELCC of this resource is 100 MW or 100%.

But 100 MW of wind, solar or four-hour storage may or may not be able to provide 100 MW at system peak. This means its ELCC will be lower than the nameplate capacity. This can be seen for solar generation in the example shown in Figure 48. It shows hypothetical hourly load and solar generation forecast for a summer day in 2030 for Platte River's system.

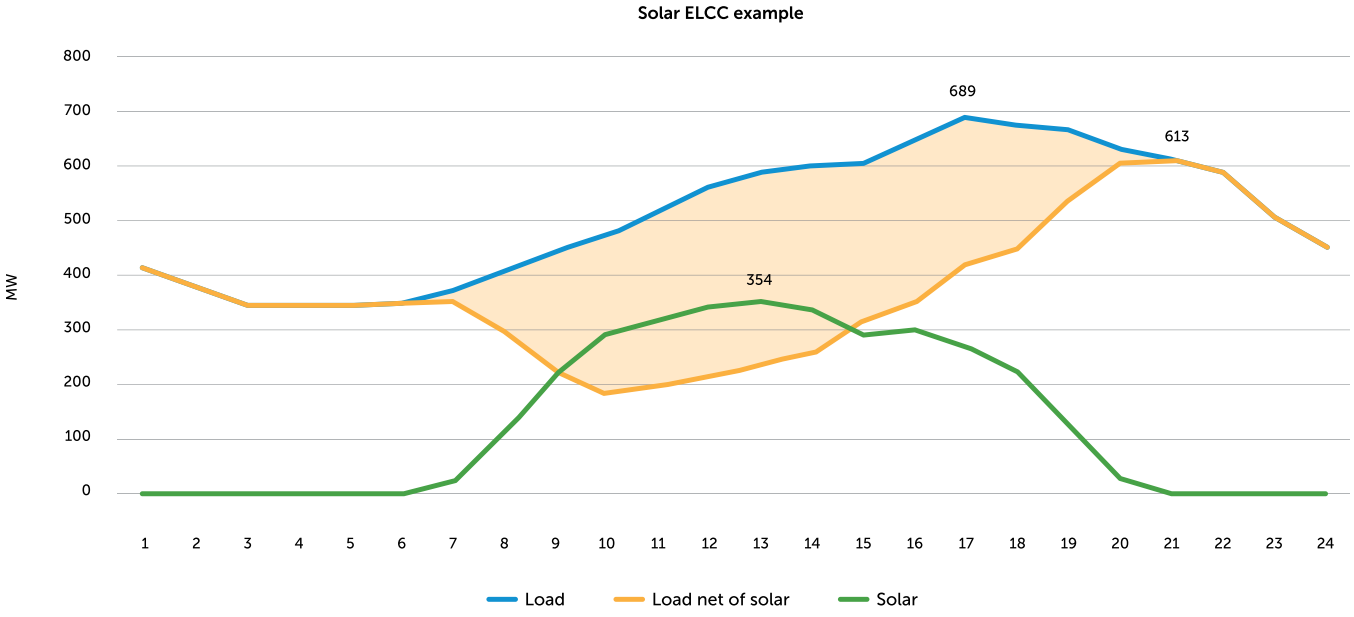


Figure 48. *Solar ELCC example*

The blue line shows hourly load for 24 hours across the day. The peak load during the day is 689 MW at hour 17 or 5 p.m. The green line shows solar generation. It starts around 6 a.m., peaks at 354 MW at 1 p.m. and drops to zero by 9 p.m. The orange line shows hourly load net of solar generation. Solar generation reduces the load by the shaded area. The orange line shows that the peak hour of the load has shifted from 5 p.m. to 9 p.m. and is 613 MW. So, the solar generation has reduced the peak demand by 76 MW (689 minus 613). While the maximum solar generation is 354, the nameplate of installed capacity of solar is 507 MW in this example. For this day, solar ELCC is 76/507=15%. In other words, installed capacity of 507 MW reduces the peak demand by 76 MW. Put another way, the effect solar had on the peak is that it reduced peak by 76 MW.

As we install more solar, its impact on reducing peak will be zero, because the peak demand hour has already moved to 9 p.m., after sunset when solar stops producing. In that case, the incremental ELCC of solar after 507 MW is zero. This example shows just one hypothetical day. In reality, ELCC calculations are computed after thousands of simulations under different load and weather conditions.

ELCC of wind and other resources follows the same declining pattern with more resource additions. As more wind is added, the incremental contribution of the next wind project to reduce peak demand continues to decline. Figure 49 shows the ELCC values of solar, wind and four-hour storage through time as computed by Astrape, which we used for this IRP. As utilities in Colorado add more of these resources over time, their ELCC contributions diminish.

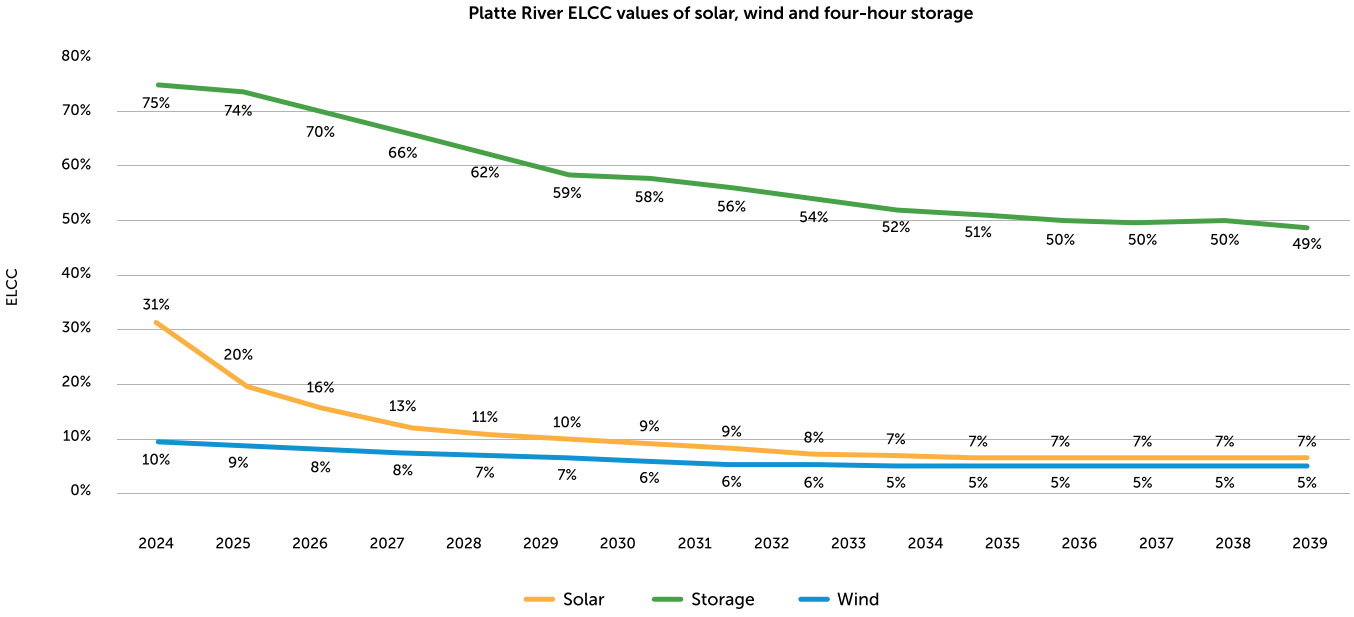


Figure 49. *Platte River ELCC values of solar, wind and four-hour storage*

Table 19 shows ELCC values of longer duration battery storage and some DER technologies, as computed by Astrape and used by Platte River in this IRP. The installation of more resources of the same type reduces that resource type's ELCC. For example, the ELCC of distributed solar is 8.5% if Colorado utilities install 500 MW. It drops to 5.8% with 4,000 MW installed.

Technology	Penetration (MW)	Average ELCC (%)	Marginal ELCC (%)
8-hour batteries	500	92.7%	91.6%
8-hour batteries	1,000	90.5%	84.4%
8-hour batteries	1,500	87.0%	75.6%
100-hour batteries	500	92.7%	91.6%
100-hour batteries	1,000	91.9%	90.8%
100-hour batteries	1,500	91.4%	90.0%
Distributed generation solar	500	8.5%	7.9%
Distributed generation solar	1,000	8.0%	7.2%
Distributed generation solar	2,000	7.2%	5.8%
Distributed generation solar	4,000	5.8%	2.9%
Beneficial electrification	100	6.9%	7.4%
Beneficial electrification	200	7.3%	8.2%
Beneficial electrification	300	7.8%	9.0%
Electric vehicles	100	32.0%	33.6%
Electric vehicles	200	33.8%	37.3%
Electric vehicles	300	35.7%	41.0%
Demand response	100	92.3%	87.3%
Demand response	200	87.1%	77.8%
Demand response	300	82.6%	70.4%

Table 19. *ELCC values of long-duration energy storage and DERs*

7.3.2.4 Extreme weather and dark calm modeling

Winter Storm Uri, which brought blackouts to Texas and stressed power supply across a much wider area, also impacted power supply in our area. Due to extremely cold weather for many days, demand for electricity continued to rise. Additionally, there was very little renewable generation for almost 80 hours during Feb. 12-16, 2021, as shown in Figure 50.

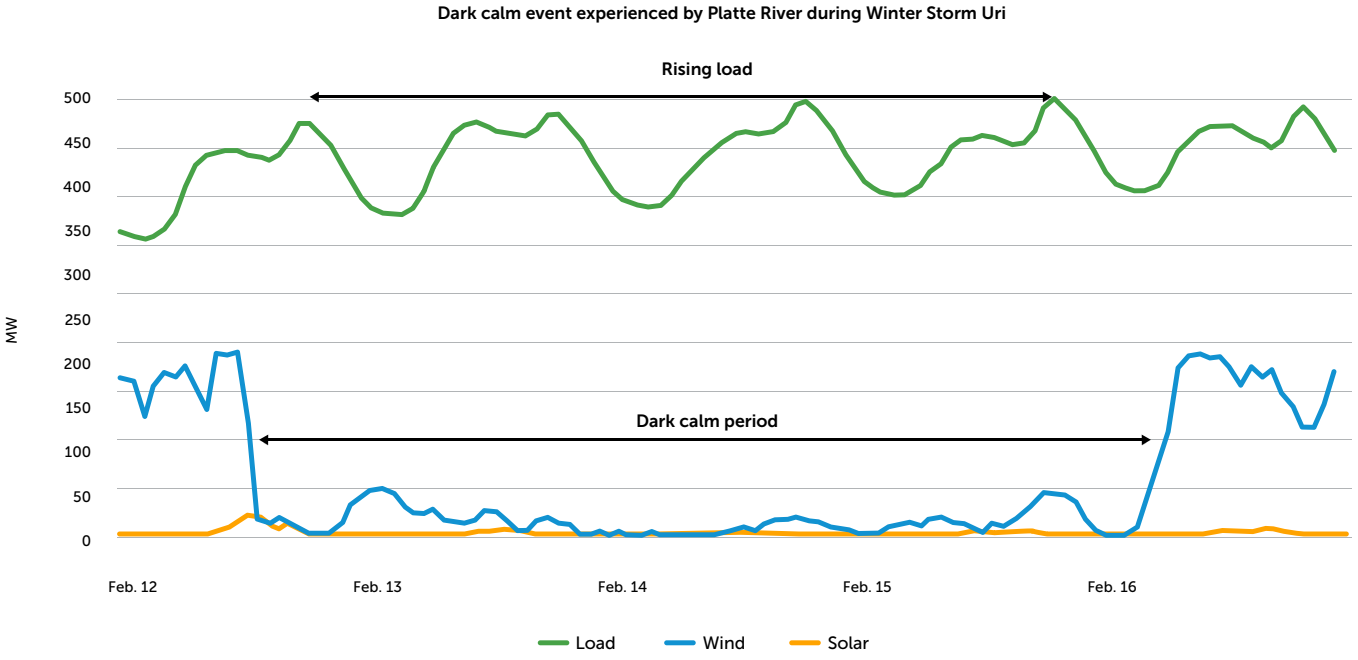


Figure 50. *Dark calm event experienced by Platte River during Winter Storm Uri*

During this 2021 dark calm, Platte River was able to serve its customers' load reliably because dispatchable coal resources were available. But after coal units retire in 2030, we may experience similar or even more severe dark calms. A fundamental requirement of an IRP is to develop supply portfolios that will be reliable under varying conditions of weather, previously experienced or not. This led us to hire ACES to conduct a study on extreme weather and dark calm events.[28]

ACES reviewed hourly weather profiles for 70 locations west of Mississippi for the past five decades (1973-2019) to estimate the frequency, duration and depth of extreme weather and dark calm events. Since these events are uncommon, ACES reviewed weather data across a wide region and over a long period of time to enhance confidence in the findings. Figure 51 shows locations of the airports where data was collected.

[28] https://www.prpa.org/wp-content/uploads/2023/04/2024IRP-Extreme-weather-events-and-Dark-Calm-Analysis-by-ACES.pdf In 2022, Platte River filed a voluntary CEP with the state of Colorado, laying out a plan to reduce its greenhouse gas emissions by at least 80% by 2030 (compared to a 2005 base line).

Figure 51. *Locations of extreme weather events*

7.3.2.5 Extreme weather events

The study found the following durations and frequencies of heat and cold waves:

Heat wave summary – west region						
Number of hours	48	72	96	120	144	168
Events per year	0.47	0.02	0.09	0.04	0.021	0.043

Table 20. *Heat wave summary - west region*

This means every other year, there is a heat wave lasting two days and every 11th year, there is a heat wave lasting four days.

Cold wave summary – west region													
Number of hours	48	72	96	120	144	168	192	216	240	264	288	312	336
Events per year	4.9	1.7	0.9	0.4	0.17	0.08	0	0	0	0	0	0	0

Table 21. *Cold wave summary - west region*

This data shows cold waves are more common with five two-day events every year and a weeklong event almost every 12th year.

The study also found that load, power and gas prices rise during these extreme events and noted these increases during winter storms Uri and Elliot and the 2020 summer heat wave in the Pacific Northwest. Because our focus with extreme weather modeling is on reliability, we assessed how extreme weather impacts load only. The study found that during these events, on average, the load could increase by about 10% relative to the normal load for that time of year. So, for reliability assessments during extreme weather, we increased the hourly load by 10%.

7.3.2.6 Dark calm events

Frequency and duration of dark calm events was assessed for the MISO North , covering parts of Illinois, Indiana, Wisconsin and Michigan; MISO Central, covering parts of Minnesota, Iowa and North Dakota; and the Northwest portion of the Electric Reliability Council of Texas (ERCOT. Table 22 shows the frequency and duration of different levels of dark calm events.

Dark calm events by location				
% of full output	48 hours	72 hours	96 hours	120 hours
MISO Central				
5%	3.0	1.25	0.5	0.25
10%	11.2	5.6	2.4	2.0
15%	6.2	11.4	3.8	4.8
MISO North				
5%	1.0	1.0	0.67	0.0
10%	5.0	1.75	0.5	1.0
15%	2.2	3.0	1.2	2.0
Northwest ERCOT				
10%	3.8	1.0	0.2	0.2
15%	3.2	3.4	3.0	1.2

Table 22. *Dark calm events by location*

As shown in Table 22, a dark calm event in MISO Central, where the output of renewable drops to 5% of total generation occurs:

- Three times during the year for two days every year
- Once per year for three consecutive days
- Every other year for four consecutive days
- Every four years for five consecutive days

Dark calm events where output of renewables drops to 10% of total generation are more frequent than events where renewable generation is only 5% of total generation. Dark calm events are less intense and less frequent in MISO North and Northwest ERCOT.

In the Plexos model, we averaged the two 5% rows for MISO Central and MISO North. Multiplying the probability of an event's occurrence with its duration yields the expected outage hours in a given year for that event. For example, as illustrated in Table 23, an average of two events with a duration of 48 hours means any given year would expect a total of 96 dark calm hours because the events last two days.

Since the events are non-additive, we sum all the expected hours to find the total expected dark calm hours in a year. In this case, an average year would see a total of 248 hours of dark calm spread across events of different durations.

Dark calm duration (hours)	48	72	96	120	Total dark calm hours
Average # of dark calm events across all regions (5% of full output)	2.000	1.125	0.585	0.125	
Expected dark calm hours per year	96	81	56.16	15	**248.16**

Table 23. *Dark calm event duration and frequency*

7.3.2.7 Transmission planning

Platte River conducts annual transmission assessment studies to plan for a system that adequately supports both short and long-term load obligations to the owner communities. The studies use transmission network modeling software and integrate forecasted owner community loads, existing and planned generation, and loads and generation from neighboring utilities.

Short-term studies evaluate system needs under the current transmission network configuration, integrating projected short-term load and generation forecasts. Evaluating long-term transmission needs includes forecasting long-term load and generation forecasts with both the current transmission system and planned transmission additions.

The study objectives are for the transmission system to perform reliably during extreme contingency situations, heavy or light load conditions and fault events. If a study identifies network deficiencies, further analysis follows to determine network expansion options to mitigate those deficiencies. Transmission studies are conducted during annual internal assessment activities, along with collaborative studies with regional transmission planning committees.

7.3.3 Need for new resources

As explained in chapter 5, we forecast our future energy needs as annual peak demand (maximum demand in any hour) and total annual energy for every hour of the year. For supply-side planning, we adjust these values with DER contribution from our customers. The net peak demand and energy demand are what Platte River needs to plan for through this IRP process. As discussed earlier in this chapter, Platte River plans to meet its future peak demand with 19.9% PRM to protect supply reliability. We also discussed that renewable and energy limited resources contribute less ELCC capacity toward the peak demand than their maximum or nameplate capacity.

Figure 52 shows the capacity requirements and capacity contributions from the existing and committed resources.

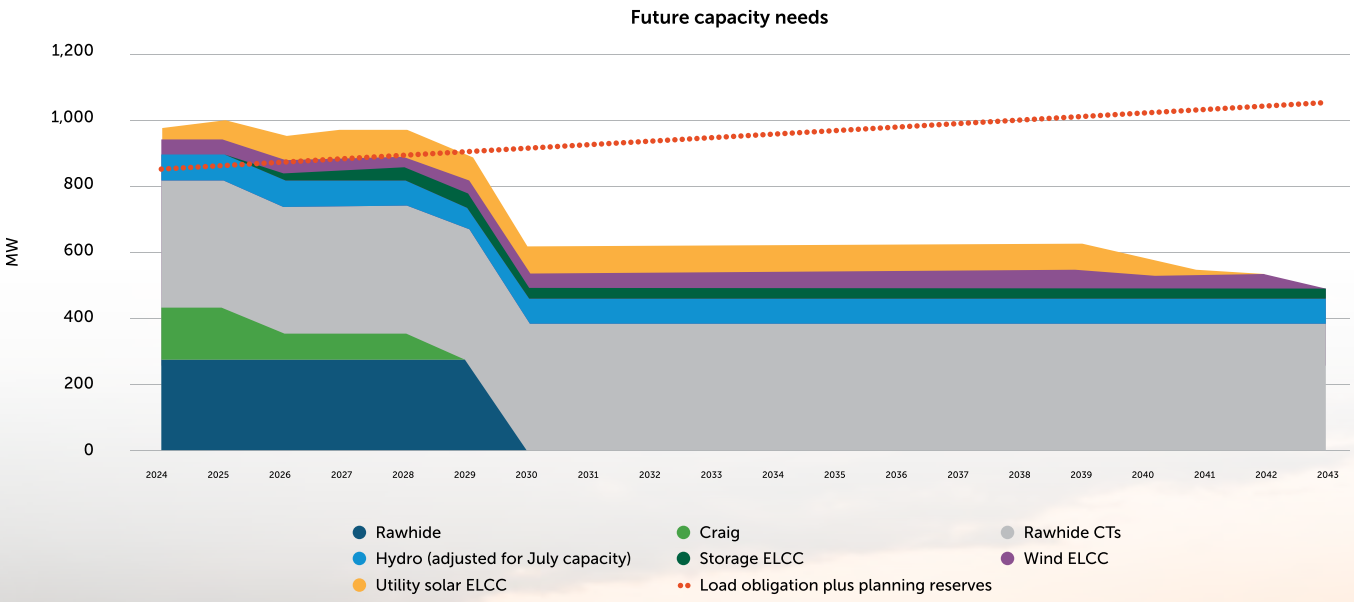


Figure 52. *Future capacity needs*

The dotted red line shows capacity requirements, while the area chart shows the capacity available. By 2029, following the retirements of Craig coal units, Platte River would need to build some new capacity, and by 2030, with the retirement of Rawhide coal plant, the additional capacity requirement rises to about 200 MW. The gap continues to expand as our load continues to increase and when our existing wind and solar PPAs reach their maturation dates. The IRP process offers recommendations to fill this gap with the lowest cost, least-emitting reliable resources.

Figure 53 shows similar chart depicting the energy deficit that will need to be filled in this IRP. Note small changes in renewable energy from year to year are due to projected changes in excess or "dumped" renewable generation.

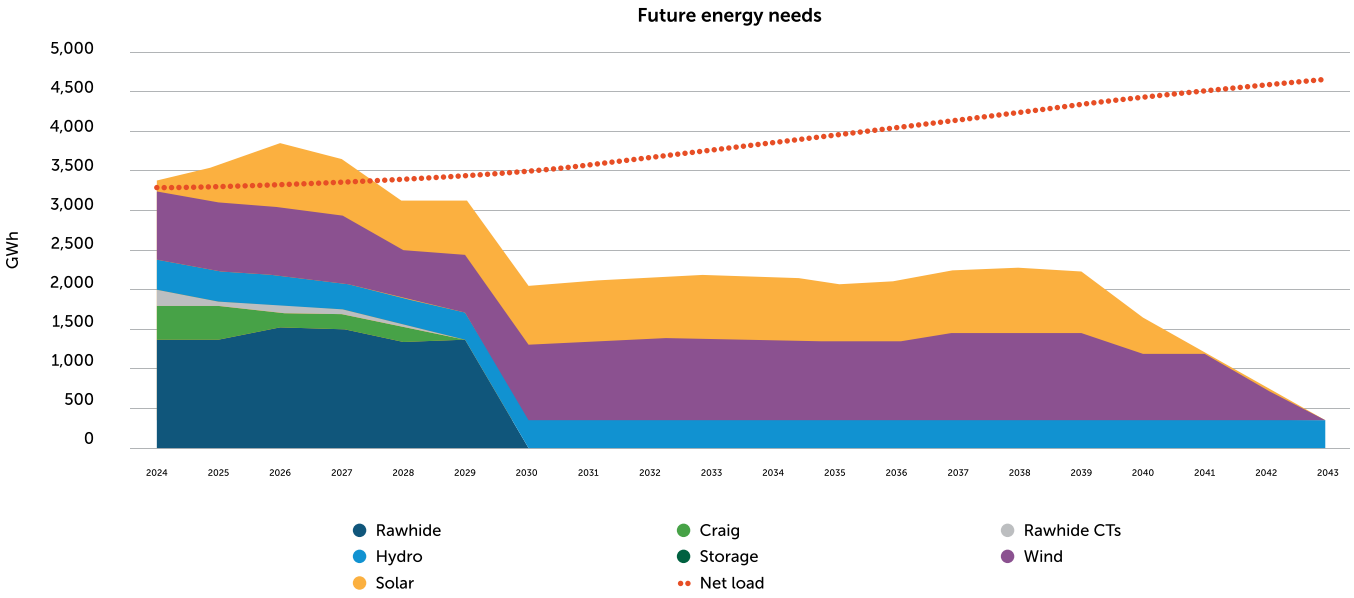


Figure 53. *Future energy needs*

Although capacity and energy gaps appear in 2030, Platte River plans to bring new resources online before 2030. This would give us time to test the availability and reliability of our new portfolio before retiring the last coal plant by the end of 2029.

7.4 Future portfolios

The portfolios selected for this IRP are designed to capture the range of potential paths available to Platte River as it transforms its generation portfolio and strives to meet the RDP goal. Reliability is the only firm constraint common to all portfolios. Other financial, operational and environmental metrics are optimized within the unique constraints of each portfolio.

Due to PRM requirements and to support reliability during dark calm events, Platte River keeps its existing combustion turbines in all portfolios. All portfolios emit some CO2 in 2030 because dispatchable noncarbon options will not be available by 2030, so thermal units are dispatched to balance the system during shortages. Portfolios that build new dispatchable thermal generation assume a blend 50% green hydrogen fuel by 2035 to reduce CO2 emissions. All dispatchable thermal generation is assumed to switch to 100% green hydrogen by 2040 and reach zero CO2 emissions. No new dispatchable thermal generation is allowed after 2030 and the IRP assumes long-duration energy storage becomes available in 2035. All portfolios assumed that future electricity prices would also include carbon taxes. Below is a brief description of all the portfolios.

7.4.1 No new carbon

In this portfolio, Platte River cannot add new thermal generation. Wind, solar and four-hour storage are the only new resource additions available until 2035, when long-duration energy storage is assumed to also become available. This portfolio is designed to test the feasibility of relying on the existing combustion turbines to maintain reliability, without adding new thermal generation.

7.4.2 Minimal new carbon

This portfolio is built to add minimal amount of new thermal generation. It adds only 80 MW of new dispatchable thermal generation.

7.4.3 Carbon-imposed cost

This portfolio is built with the cost of carbon assigned to the dispatch cost of all thermal units. This additional cost, assigning a dollar value to the externalities associated with emitting CO2, disincentivizes the construction and use of carbon-emitting resources unless it is more cost effective than other options after accounting for the social cost of carbon. Specifically, this is a least-cost portfolio where the assumed cost carbon emissions have been internalized into the optimization process.

7.4.4 Optimal new carbon

This portfolio is a balance between the additional new carbon and carbon-imposed cost portfolios in terms of reliability and cost, building 200 MW of new thermal generation. This portfolio is optimal to support reliability in all conditions, as dark calm and extreme weather events continue to become more severe, as they have in the recent past.

7.4.5 Additional new carbon

This portfolio is the result of a least-cost optimization. The model builds the lowest-cost portfolio that meets reliability standards, but adds no additional constraints to guide resource selection or operation.

7.5 Methodology

Developing future power supply portfolios is a multi-step, iterative process. Figure 54 illustrates the initial steps and the subsequent iteration through the remaining steps.

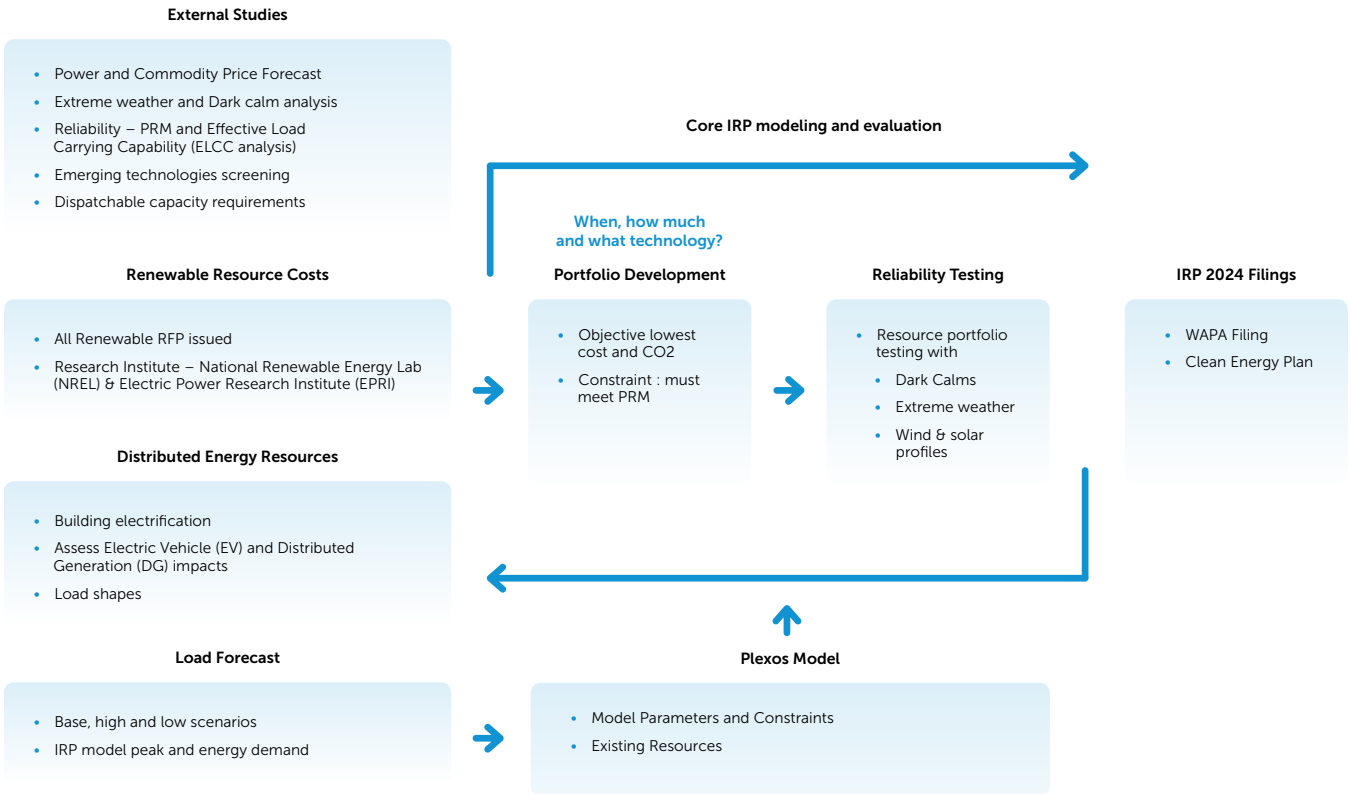


Figure 54. *IRP process*

7.5.1 Multi-step portfolio selection methodology

Data collection and review: Gather data on existing resources, including their performance and their expected operational lives; develop power and fuel price forecasts; review existing and potential future environmental regulations. These results provide a first step in understanding the planning landscape for the IRP.

Demand forecasting: Estimate future electricity demand, considering factors such as population growth, economic trends and technological advancements to project the energy needs over the planning horizon.

DER forecasting: Forecast new sources of demand, such as beneficial electrification and electric vehicles as well as additional demand-side resources, including customer-sited storage, rooftop solar, demand response and other programs.

Technology assessment: Evaluate the performance, costs, and environmental impacts of various energy technologies, including renewable energy sources, dispatchable thermal resources and energy storage. Based on the results of this high-level evaluation, Platte River can eliminate some technologies from consideration.

Stakeholder engagement: Collect feedback from a broad range of stakeholders. Community members, local businesses and advocacy

organizations are invited to offer their ideas and raise any concerns they have with the IRP process. This collaborative approach helps portfolios reflect the range of interests and priorities in the communities we serve.

7.5.2 Portfolio iterations

Optimization modeling: Use Plexos to develop and evaluate different portfolios of energy resources. Each portfolio is the result of a unique mix of inputs and constraints designed to test different aspects of the planning criteria, such as financial sustainability or environmental responsibility.

Reliability testing: Conduct reliability testing to identify uncertainties and potential challenges associated with different resource options. With high penetration of variable generation, the most critical risk tests quantify the system's exposure to dark calms or extreme weather. Platte River also reviews potential challenges associated with excessive energy length (too much energy produced compared to load) in a region expected to add substantial amounts of renewable energy in the future.

Sensitivity analysis: Explore how different external factors, such as fuel and market prices or emissions, might influence the performance of the portfolios. This helps develop plans that should be resilient under a range of future outcomes.

7.6 Reliability testing of portfolios

Because reliability is a foundational pillar, we first make sure each candidate portfolio is sufficiently reliable. As a starting point, a least-cost portfolio is developed to fill the capacity and energy gaps identified above while meeting the PRM requirement for every year of the planning horizon. Meeting the annual PRM requirement while applying the ELCC to energy-limited resources is useful, but does not test or guarantee reliability during extreme weather events or dark calms. So we conducted additional reliability testing through the Monte Carlo functionality in Plexos to understand how the portfolios might behave under stress conditions. Using the data from the extreme weather report supplied by ACES and historical weather data from Vaisala, we modeled different system conditions with the following variables:

1. **Weather:** Wind and solar profiles reflecting conditions from 1997-2019 (hourly profiles for 24 years), drawn with equal probability across the suite of simulations. In our runs, with 504 iterations, each weather year was experienced 21 times.

2. **Thermal unit outages:** The software randomly draws the timing of thermal unit outages. The duration of outages is also hypothetical, but the software does align the random outages with the known long-term forced outage rate over the course of many draws.

3. **Load forecast error:** Each iteration simulated a potential deviation from the near-term load forecast. This represents a shift in load drivers, such as population changes or economic indicators, over the one-to-four-year horizon, which is too short for the utility to respond to. The system, as built, would need to cover these near-term divergences before new resources could be brought online in response. For this IRP, Table 24 summarizes the potential load forecast error outcomes.

LFE	Probability
-4%	7.26%
-2%	24.10%
0%	37.28%
2%	24.10%
4%	7.26%

Table 24. *Potential load forecast error outcomes*

4. **Dark calm events:** Based on observed historical events, the model simulated weather events with impacts on both load and weather-dependent generation. These events could last between one and five days, with a two-day event being the most common. Often, dark calm events occur with extreme weather events. In any year, the system would expect to experience a total of 248 hours of extreme weather conditions distributed across several events. As with thermal outages, specific years could experience higher or lower than average dark calm outages with the long-term average converging to the expected value over may iterations. Across all 504 iterations of our reliability modeling, the dark calm hours in a year varied from a low of 119 hours to a high of 458 hours. Specific details on the impact to wind, solar and load are described below.

    a. **Load:** Load is modeled to increase by 10% during the event, which is consistent with data seen in other regions during extreme weather events. This is primarily driven by increased heating load during winter storms while cooling load is expected to increase during heat dome events in the summer. This increase captures the load already embedded in the load forecast.

    b. **Building heating:** During extreme winter storms, some new load from heat pumps is expected to shift to much less efficient electrical resistance heating as temperatures drop below their operating ranges. This increase in load is captured individually and is quantified by the consultant who supplied the beneficial electrification forecast.

    c. **Solar:** During the winter months, solar generation during a dark calm averages 5% of its nameplate. These generators can experience a variety of issues including snow cover or icing, overcast skies or debris or dust buildup due to high winds. In the summer months, solar output during a dark calm event averages 10% because summer outages are often caused by extended overcast weather.

    d. **Wind:** During the winter months, wind generation during a dark calm averages 5% of its nameplate. This reduced production is primarily due to blade icing, but overspeed (wind too strong to safely operate turbines) also drives some outages. In the summer months, output during a dark calm event also averages 5%, as summer wind droughts, especially during heat dome events, are common.

7.7 Modeling tool

Platte River used the Plexos simulation and modeling tool for the 2024 IRP. Plexos is an economic dispatch and capacity expansion model developed by Energy Exemplar (www.energyexemplar.com).

08 IRP study results

This chapter presents the modeling results for each portfolio, with comparisons of their most important metrics including cost, CO2 emission reductions and renewable energy penetration—metrics that align with Platte River's foundational pillars of financial sustainability and environmental responsibility. As noted previously, every portfolio considered in this IRP meets our reliability criteria (another foundational pillar).

8.1 Summary of five portfolios

Every portfolio assumed a common starting point of existing resources plus new, near-term resource additions from recently signed agreements and solicitations under development. These are considered "committed" resources and the IRP process considers them "given," just like existing resources. These near-term additions represent Platte River's best estimate of solicitation results. In the current environment, project timelines, pricing and size are uncertain and subject to change. Platte River remains flexible and will adjust future capacity acquisitions to compensate for changes to current acquisitions.

8.1.1 Load forecast with DER assumptions

Customer load and DER projections for all the portfolios are similar. Therefore, the various portfolios primarily represent different supply-side options. Load forecast and DER projections are discussed in detail in chapter 5. Figures 37 and 38 in Chapter 5 show annual peak and energy forecasts and DER impact through the planning period. Figures 55 and 56 illustrate annual peak and energy forecasts for quick reference.

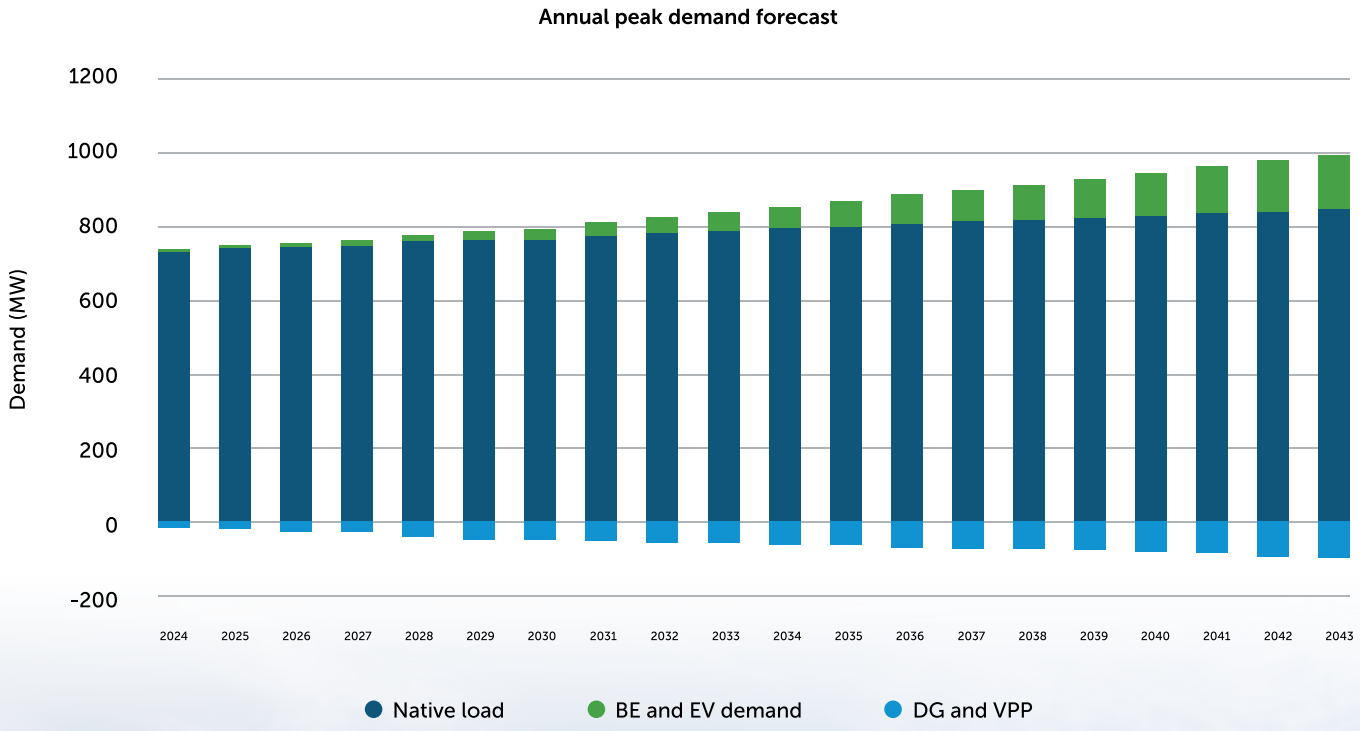


Figure 55. *Annual peak demand forecast*

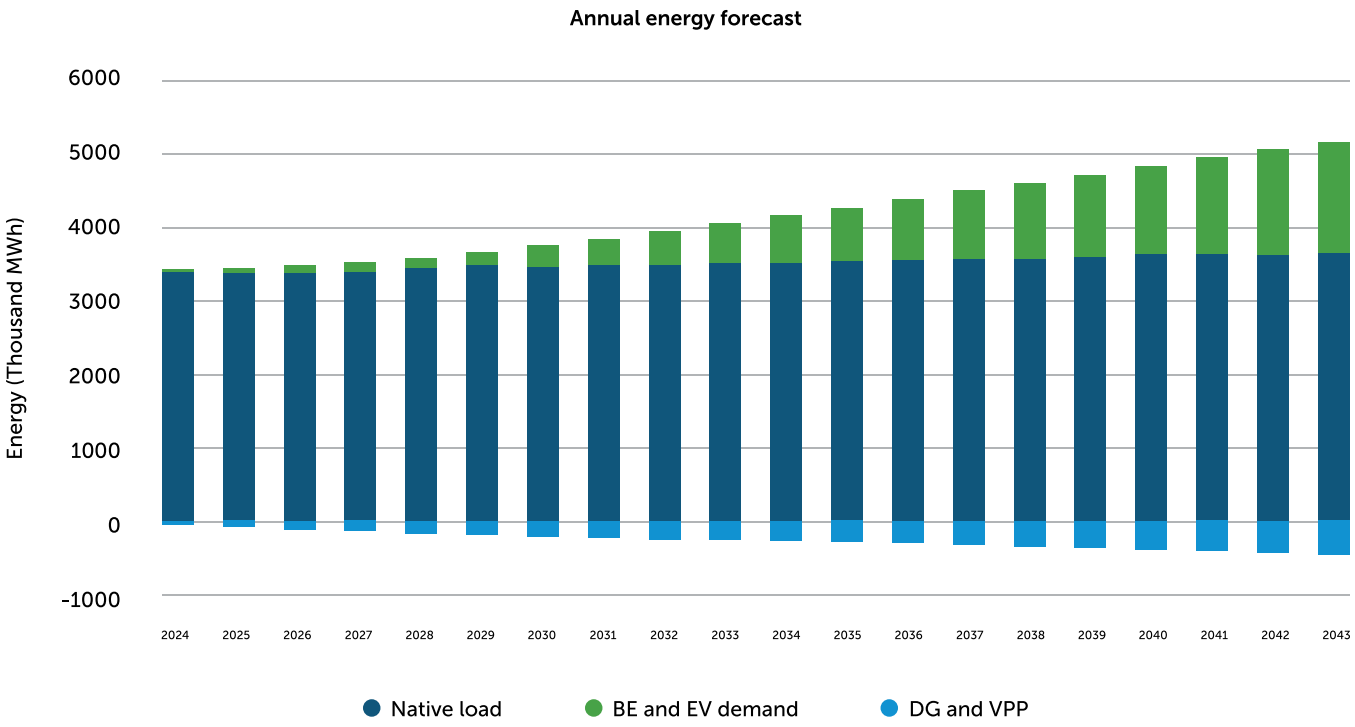


Figure 56. *Annual energy forecast*

Figures 55 and 56 illustrate that DERs are projected to grow much faster than the base load. Distributed generation, which is largely rooftop solar, reduces base peak load by 7% in 2030 and 10% by 2040. The growth of building beneficial electrification and EVs is even faster. Together, these add about 8% to the annual energy demand by 2030 and 34% by 2040.

Table 25 summarizes the utility-scale resources common to all portfolios before Platte River developed and optimized its expansion plans. As described in earlier sections, there are also DER resources embedded in every portfolio that are not subject to optimization during the modeling process.

	Existing resources MWs	Near-term solicitation MWs	Total MWs
Wind	231	250	481
Solar	52	300	352
Battery energy storage systems	1	50	51
Long-duration storage	0	10	10

Table 25. *Existing and committed resources*

Additionally, the following assumptions are common to all the portfolios:

- No new thermal generation is constructed after 2030 and all subsequent resource additions will be noncarbon-emitting resources.
- Long-duration energy storage technology is available from 2035 onwards.
- New thermal generation uses a fuel blend containing 50% green hydrogen from 2035 onwards.
- All thermal generation uses 100% green hydrogen fuel from 2040 onwards, eliminating CO2 emissions.

The portfolios developed in this IRP cover a broad range of potential pathways Platte River might consider as it decarbonizes its power supply portfolio. We are committed to completely retire coal generation by the end of 2029 so the expansion plans include aggressively adding renewable energy. Each portfolio adds 600-800 MW of new renewable energy capacity, although the mix between wind and solar may be different in each portfolio as the optimization seeks to minimize cost while meeting reliability metrics.

Platte River also models additional thermal units and storage to complement its renewable energy acquisitions and comply with reliability criteria. The main differences between the portfolios are the choices about adding thermal resources and storage.

Table 26 summarizes the resources added during the resource acquisition period, as well as the final buildout at the end of the planning horizon in 2043. Note the solar and wind energy additions closely converge by 2043, with only a 100 MW capacity spread between the highest and lowest additions. This is because all portfolios depend heavily on renewable energy, with thermal energy largely acting as a reliability backstop.

	No new carbon	Minimal new carbon	Carbon-imposed cost	Optimal new carbon	Additional new carbon (lowest cost)
2024-2029 incremental additions (MWs)					
Wind	300	300	400	400	300
Solar	450	500	350	300	300
Four-hour storage	2,850	1,050	275	175	100
Long-duration storage	10	10	10	10	10
Dispatchable thermal	0	80	160	200	240
Final 2043 Portfolio (MWs)					
Wind	885	885	985	885	985
Solar	600	600	550	600	450
Four-hour storage	2,850	1,100	400	275	175
Long-duration storage	10	160	10	160	110
Dispatchable thermal	0	80	160	200	280

Table 26. *Summary of five portfolios*

Additional detailed tables are provided in the following section for each portfolio, showing annual capacity additions by each category, further divided into new and existing resources.

8.2 Individual portfolio details

In this section we describe notable features of each portfolio and show the 20-year projections for each by year and by resource type.

8.2.1 No new carbon portfolio

This portfolio does not add any new thermal generation but continues to operate the existing natural gas CTs at Rawhide. To serve its future energy and reliability needs, Platte River adds an incremental 300 MW of wind and 450 MW of solar. To maintain reliability, the portfolio relies on four-hour battery storage with a total addition of 2,850 MW by 2029.

The substantial buildout of four-hour storage in the early years eliminates the need for additional storage during the planning period. Table 27 shows annual resource additions over the planning horizon for this portfolio.

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Coal	431	431	354	354	354	280	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	81	78	75	72	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70
Frame units (existing)	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388
Aeroderivative units (new)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	30	0	0
Solar (new)	0	150	300	300	450	450	450	450	500	500	500	500	500	550	600	700	550	450	550	600
Wind	231	231	231	231	231	231	231	291	291	291	285	285	285	285	285	285	225	225	225	0
Wind (new)	0	0	0	200	300	300	360	300	300	300	400	400	400	400	400	400	560	660	660	885
Storage 4-hr	2	2	27	52	1452	2852	2852	2852	2852	2852	2852	2852	2852	2852	2852	2852	2850	2850	2850	2850
Storage LT	0	0	0	0	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Solar DER	46	62	83	105	126	141	155	169	180	190	200	210	223	236	251	266	282	299	318	337
Storage DER	3	6	10	17	24	32	39	47	54	63	70	76	82	86	90	94	101	108	115	123
Total	**1234**	**1399**	**1520**	**1772**	**3457**	**4806**	**4607**	**4628**	**4698**	**4716**	**4827**	**4843**	**4861**	**4929**	**4997**	**5117**	**5088**	**5090**	**5186**	**5263**

Table 27. *No new carbon portfolio annual resource additions (in MW)*

8.2.2 Minimal new carbon portfolio

This portfolio allows only 80 MW of new thermal generation. Due to this constraint, this portfolio requires a substantial amount of four-hour storage by 2030, as much as 1,050 MW. This portfolio also adds 300 MW of wind and 500 MW of solar by 2030. This is the most additional solar among all the portfolios, complementing the four-hour storage needed to cover daily peaks. After 2030, more wind and solar are added to meet growing energy needs while short- and long-duration energy storage is added to support reliability. Table 28 shows annual resource additions over the planning horizon for this portfolio.

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Coal	431	431	354	354	354	280	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	81	78	75	72	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70
Frame units (existing)	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388
Aeroderivative units (new)	0	0	0	0	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
Solar	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	30	0	0
Solar (new)	0	150	300	300	450	500	500	500	500	500	550	550	600	700	700	750	600	500	600	600
Wind	231	231	231	231	231	231	231	291	291	291	285	285	285	285	285	285	225	225	225	0
Wind (new)	0	0	0	200	300	300	360	300	300	300	300	400	400	400	400	400	560	660	660	885
Storage 4-hr	2	2	27	52	552	1052	1052	1052	1052	1052	1052	1052	1052	1052	1052	1052	1050	1050	1075	1100
Storage LT	0	0	0	0	10	10	10	10	10	10	10	10	10	10	60	60	60	110	110	110
Solar DER	46	62	83	105	126	141	155	169	180	190	200	210	223	236	251	266	282	299	318	337
Storage DER	3	6	10	17	24	32	39	47	54	63	70	76	82	86	90	94	101	108	115	123
Total	**1234**	**1399**	**1520**	**1772**	**2637**	**3136**	**2937**	**2958**	**2978**	**2996**	**3057**	**3173**	**3241**	**3359**	**3427**	**3497**	**3468**	**3520**	**3641**	**3693**

Table 28. *Minimal new carbon portfolio annual resource additions (in MW)*

8.2.3 Carbon-imposed cost portfolio

The carbon-imposed cost attempts to measure the economic and environmental cost of CO2 for society. Due to the increased cost for CO2 emissions, this portfolio limits the addition of new dispatchable thermal units to 160 MW and favors four-hour battery storage, with 275 MW of new capacity. As with other plans, wind and solar are the primary energy sources, with 400 MW of new wind and 350 MW of new solar by 2030. After 2030, additional wind and solar are added to meet growing energy needs while short- and long-duration energy storage is added to support reliability. Table 29 shows annual resource additions over the planning horizon for this portfolio.

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Coal	431	431	354	354	354	280	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	81	78	75	72	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70
Frame units (existing)	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388
Aeroderivative units (new)	0	0	0	0	160	160	160	160	160	160	160	160	160	160	160	160	160	160	160	160
Solar	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	30	0	0
Solar (new)	0	150	300	300	300	350	350	350	400	450	450	450	450	450	450	500	450	450	500	550
Wind	231	231	231	231	231	231	231	291	291	291	285	285	285	285	285	285	225	225	225	0
Wind (new)	0	0	0	200	400	400	460	400	400	400	400	500	500	500	600	600	660	760	760	985
Storage 4-hr	2	2	27	52	127	277	277	302	327	352	377	377	377	377	377	377	375	375	375	400
Storage LT	0	0	0	0	10	10	10	10	10	10	10	60	60	60	60	60	110	160	160	160
Solar DER	46	62	83	105	126	141	155	169	180	190	200	210	223	236	251	266	282	299	318	337
Storage DER	3	6	10	17	24	32	39	47	54	63	70	76	82	86	90	94	101	108	115	123
Total	**1234**	**1399**	**1520**	**1772**	**2242**	**2391**	**2192**	**2238**	**2333**	**2426**	**2462**	**2628**	**2646**	**2664**	**2782**	**2852**	**2873**	**3025**	**3071**	**3173**

Table 29. *Carbon-imposed cost portfolio annual resource additions (in MW)*

8.2.4 Optimal new carbon portfolio

This portfolio adds 200 MW of new dispatchable thermal resources and 175 MW of new battery storage as it balances capacity support across both thermal and batteries. Like the carbon-imposed cost portfolio, this portfolio adds 400 MW of wind but slightly less solar, with 300 MW of new capacity by 2030. After 2030, additional wind and solar are added to meet growing energy needs while short- and long-duration energy storage is added to support reliability. Table 30 shows annual resource additions over the planning horizon for this portfolio.

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Coal	431	431	354	354	354	280	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	81	78	75	72	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70
Frame units (existing)	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388
Aeroderivative units (new)	0	0	0	0	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
Solar	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	30	0	0
Solar (new)	0	150	300	300	300	300	300	300	300	300	400	400	400	400	400	450	450	450	550	600
Wind	231	231	231	231	231	231	231	291	291	291	285	285	285	285	285	285	225	225	225	0
Wind (new)	0	0	0	200	400	400	460	400	400	400	400	500	500	500	600	600	660	660	660	885
Storage 4-hr	2	2	27	52	102	177	177	202	227	252	252	252	252	252	252	252	250	250	250	275
Storage LT	0	0	0	0	10	10	10	10	10	10	10	60	60	60	60	60	110	160	160	160
Solar DER	46	62	83	105	126	141	155	169	180	190	200	210	223	236	251	266	282	299	318	337
Storage DER	3	6	10	17	24	32	39	47	54	63	70	76	82	86	90	94	101	108	115	123
Total	**1234**	**1399**	**1520**	**1772**	**2257**	**2281**	**2082**	**2128**	**2173**	**2216**	**2327**	**2493**	**2511**	**2529**	**2647**	**2717**	**2788**	**2840**	**2936**	**3038**

Table 30. *Optimal new carbon portfolio annual resource additions (in MW)*

8.2.5 Additional new carbon portfolio

The primary objective of this portfolio is to minimize costs. To do so, this portfolio relies on 240 MW of new dispatchable thermal resources to provide firm capacity. Renewables still supply most of the energy, with 300 MW of new wind and 300 MW of new solar by 2030. To help manage the renewable energy, this portfolio adds 100 MW of storage. After 2030, additional wind and solar are added to meet growing energy needs while short- and long-duration energy storage is added to support reliability. Table 31 shows annual resource additions over the planning horizon for this portfolio.

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Coal	431	431	354	354	354	280	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	81	78	75	72	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70
Frame units (existing)	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388
Aeroderivative units (new)	0	0	0	0	240	240	240	240	240	240	240	240	240	240	240	240	240	280	280	280
Solar	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	30	0	0
Solar (new)	0	150	300	300	300	300	300	300	300	300	300	350	350	350	350	400	400	350	400	450
Wind	231	231	231	231	231	231	231	291	291	291	285	285	285	285	285	285	225	225	225	0
Wind (new)	0	0	0	200	300	300	360	300	300	300	500	500	500	600	600	600	660	760	760	985
Storage 4-hr	2	2	27	52	52	102	102	102	127	152	152	152	152	152	152	152	150	150	150	175
Storage LT	0	0	0	0	10	10	10	10	10	10	10	60	60	60	60	60	110	110	110	110
Solar DER	46	62	83	105	126	141	155	169	180	190	200	210	223	236	251	266	282	299	318	337
Storage DER	3	6	10	17	24	32	39	47	54	63	70	76	82	86	90	94	101	108	115	123
Total	**1234**	**1399**	**1520**	**1772**	**2147**	**2146**	**1947**	**1968**	**2013**	**2056**	**2267**	**2383**	**2401**	**2519**	**2537**	**2607**	**2678**	**2770**	**2816**	**2918**

Table 31. *Additional new carbon portfolio annual resource additions (in MW)*

8.3 Comparative analysis of portfolios

8.3.1 Portfolio costs

As part of "least-cost" resource planning and optimization, the Plexos model captured relevant incremental costs associated with building, acquiring and operating the power supply portfolios over the 20-year planning horizon. Platte River excluded other costs from the model, like depreciation of existing transmission and generation infrastructure, cost of DERs and administrative and general costs. While these additional costs are important, they are not relevant to the capacity expansion planning process. The cost comparison presented here is not a rate forecast because it does not capture the full revenue requirement needed to set rates. Figure 57 compares the annual cost of all five portfolios.

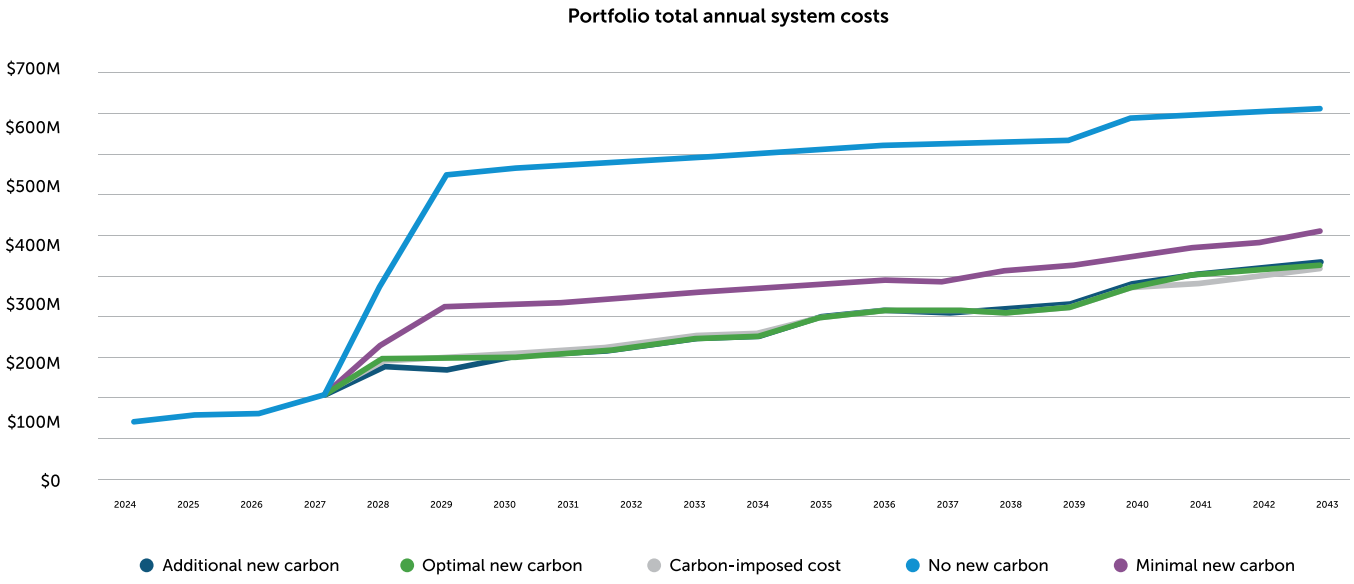


Figure 57. *Portfolio total annual system costs*

The no new carbon portfolio stands out as significantly more expensive, with the large buildout of four-hour storage starting in 2027. Annual costs exceed $500 million per year by 2028 and continue an upward trend. The minimal new carbon portfolio is also noticeably more expensive than others, again due to the large battery buildout, with annual costs exceeding $300 million by 2029. The remaining portfolios' costs are similar, with some annual deviations due to small changes in resource size and timing. Looking at the present value of the total portfolio cost in Table 32, costs for the carbon-imposed cost, optimal new carbon and additional new carbon portfolios are within 1%

of each other. But the minimal new carbon portfolio is about 20% more expensive than the three lower-cost portfolios (on a net present value basis), while the no new carbon portfolio is almost twice as expensive, costing an extra $2.6 billion over the planning horizon.

20-year net present value ($000)	
No new carbon	$5,344,991
Minimal new carbon	$3,372,202
Carbon-imposed cost	$2,779,024
Optimal new carbon	$2,772,407
Additional new carbon	$2,761,036

Table 32. *Portfolio net present value cost comparison*

As noted previously in this report, the portfolios rely on different technologies to supply differing services. Cost, energy and capacity breakouts in Table 33 highlight the complementary roles of renewable energy and thermal units in the optimal new carbon portfolio. In this case, when looking at the net present value of costs from 2030 through 2043, thermal units account for about 29% of the total cost while supplying almost 58% of the firm capacity and only about 7% of the energy. In contrast, noncarbon resources account for nearly 49% of the cost while contributing just over 91% of the energy but only about 23% of the firm capacity. The thermal resources are more cost-efficient at contributing capacity while noncarbon resources are more cost-efficient at contributing energy. A reliable and low-cost portfolio needs an optimal combination of both capacity and energy. While battery storage does not generate energy, it shifts the renewable production to omitted renewable production hours, thereby contributing to capacity needs and supporting renewable energy integration.

	% of cost	% of generation	% of capacity
Thermal	29.2%	6.9%	57.9%
Noncarbon	48.8%	91.5%	23.1%
Battery storage	15.1%	0.0%	19.0%
Purchases	6.9%	1.6%	0.0%
Total	**100.0%**	**100.0%**	**100.0%**

Table 33. *Optimal new carbon portfolio: cost, energy and capacity contribution breakout*

8.3.2 Portfolio CO2 emissions

Lowering CO2 emissions is a primary metric driving portfolio development and selection. While there are many ways to quantify a portfolio's emissions, this IRP uses the methodology developed in conjunction with Colorado's Clean Energy Plan (CEP)[29] rules.

Under this methodology, stack emissions from the portfolio are adjusted to reflect additional emissions associated with energy purchases while energy sales assign the associated CO2 to the counterparty buying energy. This netting prevents companies from avoiding emissions by outsourcing generation to an outside counterparty and helps Colorado measure total CO2 emissions due to electricity production and consumption within the state. This methodology also avoids penalizing companies for supplying energy to other utilities. This methodology is a good match for a future market where energy is entirely sold into and purchased from the market without regard to how individual companies balance load and generation. Figure 58 shows annual percent reduction of CO2 emissions for each portfolio relative to Platte River's 2005 baseline emissions.

[29] In 2022, Platte River filed a voluntary CEP with the state of Colorado, laying out a plan to reduce its greenhouse gas emissions by at least 80% by 2030 (compared to a 2005 base line).

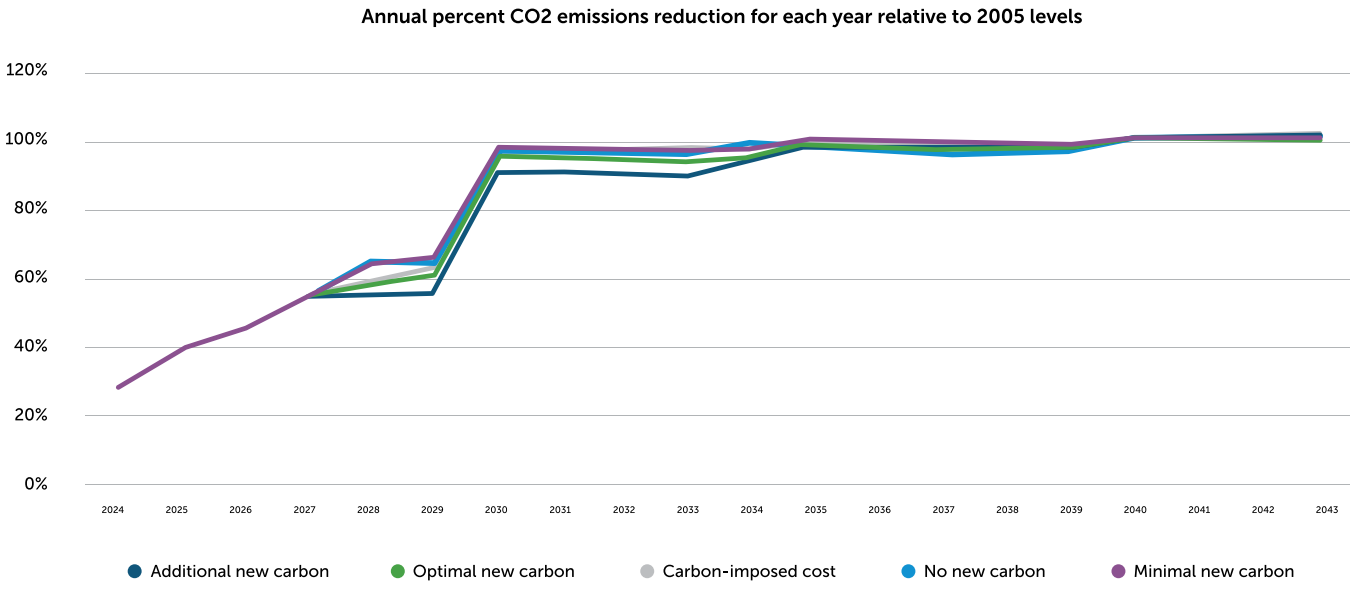


Figure 58. *Annual percent CO2 emissions reduction for each year relative to 2005 levels*

Starting in 2025, Platte River makes substantial progress to reduce CO2 emissions due to the renewable energy additions and phased coal retirements. By 2027, we expect all five portfolios to achieve a 55% CO2 reduction. By 2030, the additional new carbon portfolio achieves a 91% reduction, while the remaining portfolios have reductions greater than 95%. After 2035, when the remaining thermal units should begin partially burning green hydrogen, the average carbon reduction for all five portfolios is 99%. This rises to 100% when we assume that all thermal units will transition to 100% hydrogen fuels in 2040, eliminating CO2 emissions.

All portfolios comply with:

- The framework in SB23-198 requiring Platte River to model at least one plan that can demonstrate 46% CO2 reduction (from 2005 levels) by 2027 and one plan that reduces carbon further than its filed CEP; and

- Platte River's voluntary CEP showing its plan to achieve at least 80% CO2 reduction (from 2005 levels) by 2030.

In addition to CO2 emissions reductions, emissions from other pollutants, including volatile organic compounds, carbon monoxide and nitrogen oxides, will also decrease with the coal plant retirements. We assume the new dispatchable generation will use the best available control technologies to maintain compliance with state laws and minimize environmental impact on water resources and air quality.

8.4 Recommendation

8.4.1 Optimal new carbon portfolio

Planning is a dynamic process, and the IRP is snapshot in time. The 2024 IRP presents a possible future based on the best information available in the summer of 2023. The five portfolios presented in this chapter cover a wide range of future paths. All five portfolios provide reliable electricity supplies during the planning horizon under our assumed set of conditions and variables. But our assumed conditions will probably change. In fact, they will almost certainly change in the long run because we are living amid rapid transition. While all five portfolios provide hypothetical options to meet load requirements and reduce carbon emissions, we must select one that:

- Presents a path towards meeting our RDP and state goals.
- Meets Platte River's three pillars of reliability, financial sustainability and environmental responsibility.
- Presents a path where the actions taken in early years will not unnecessarily limit future options or intensify risks.

The following section highlights the key merits of each portfolio and provides a recommendation.

The **no new carbon portfolio** does not add any new CO2 emitting sources, but it is the most expensive due to heavy reliance on four-hour storage batteries. It builds 2,850 MW of new batteries, almost three times our expected peak demand in 2030. Consequently, it costs about twice as much as some other portfolios. As a not-for-profit entity, Platte River must pass these higher costs to the owner communities, causing significant rate shock.

The no new carbon portfolio does not offer the least CO2-emitting path, as it relies heavily on existing dispatchable generation to complement renewable generation. This portfolio fails the financial sustainability test and is not as effective in reducing CO2 emissions post-2030 as other portfolios. Due to heavy reliance on four-hour battery storage, this portfolio may be unreliable in a dark calm event that spans more days than we have modeled. This portfolio does not present a plausible future path.

The **minimal new carbon portfolio** builds 80 MW of new thermal generation and 1,050 MW of new storage batteries, almost 50% more than

the expected peak demand in 2030. This portfolio emits the least CO2 but is more than 20% more costly than the optimal new carbon portfolio. Just like the no new carbon portfolio, due to heavy reliance on four-hour storage batteries, this portfolio may be unreliable in a dark calm that spans multiple days. Because it does not meet Platte River's requirements for reliability or financial sustainability, this portfolio does not present a workable future path.

The **carbon-imposed cost portfolio** builds 160 MW of new thermal generation and presents a workable path. While this portfolio is reliable for the historically experienced weather uncertainties, it may not be reliable if weather events continue to become more extreme as they have in the recent past.

The **optimal new carbon portfolio** builds 200 MW of new efficient thermal generation and presents a viable path. This portfolio presents a balance between the additional new carbon and carbon-imposed cost portfolios in both cost and the amount of new thermal generation. This portfolio better supports reliability if weather events continue to become more extreme, as they have in the recent past. This is our recommended portfolio.

The **additional new carbon portfolio** builds 240 MW of new efficient and flexible thermal generation. It is the lowest-cost portfolio but emits more CO2 than some other portfolios that also meet reliability and financial sustainability pillars. This portfolio presents a workable future path.

The carbon-imposed cost, optimal new carbon and additional new carbon portfolios are potentially workable options. There are important differences among the three. After careful consideration, Platte River recommends the optimal new carbon portfolio because it optimally balances the organization's three foundational pillars, offers more flexible and lower-risk early decisions, has the robustness to withstand changes in assumptions and helps advance the 100% noncarbon energy goal of the RDP.

The recommended portfolio is a possible path for the future and not a firm plan. Platte River will further refine this path during implementation, incorporating market conditions, technology evolution, availability, and cost and timing of new resources. This plan will evolve as needed to align with our board's direction and our owner communities' wishes. Staff will continue to refine this portfolio with new data, assumptions, and market conditions. With these refinements and improvements, Platte River will continue to advance toward a 100% noncarbon supply mix while maintaining its three pillars of safely providing reliable, environmentally responsible and financially sustainable energy and services.

8.5 Risk assessment and sensitivity analysis

Platte River developed all five portfolios using several assumptions, assessments and forecasts about commodity prices, customer load growth, costs of renewables, DER adoption rates, market evolution, technology evolution, and other inputs. But these inputs are unlikely to occur exactly as assumed, requiring us to adapt. In this section, we outline the risks our plan faces, summarize our sensitivity analyses and provide options to adjust the plans for key risks. As time passes and newer information is available, we will modify our plans.

8.5.1 IRP risks and barriers

As Platte River moves forward with this IRP implementation, we must consider two types of risks. First, there are execution risks that complicate portfolio implementation. These risks tend to be very specific to the composition of the portfolio, driven by large, complex external factors (such as global supply chains) and are difficult to hedge because they are unique and difficult to forecast. We discuss these risks in detail below.

8.5.1.1 Execution risks

- **Cost escalation** – As discussed in section 3.4.3, renewable costs continue to escalate dramatically. Platte River uses the latest market data to develop plans, but costs continue to rise, and new generation may be more expensive than anticipated. Renewable energy seems to carry the highest exposure due to both high market demand and complex, immature supply chains. Thermal generation has seen moderate escalation and other resource additions could be impacted by trade policies. Platte River must be prepared to adjust to the best portfolio mix to reflect evolving cost considerations.

- **Siting complications** – Individual projects have unique siting challenges. Platte River must address community concerns about the impact of a project itself or its transmission connections. Local regulation can also shift rapidly and require project modifications that often add costs. Projects may also encounter unexpected geological, hydrological or environmental conditions.

- **Technology evolution** – Our proposed portfolios assume a specific timeline of technology readiness. This forecast is based on our best estimates, but technology development is beyond Platte River's control. If specific storage technologies fail to mature or hydrogen is not available at the required volumes, the portfolio would need to be reoptimized to accommodate this new reality. More specifically, we assumed long-duration energy storage and green hydrogen will be available and economically viable for commercial deployment in 2035 to help continue to decarbonize Platte River's resource mix . If these technologies are not available at the projected dates or are available sooner, our decarbonization schedule will change accordingly.

- **DER adoption rates** – Platte River is proactively working with its owner communities to forecast and incentivize customer-sited resources. Like other technology forecasts, the exact trajectory of deployment of many new and emerging technologies is uncertain. Rooftop solar, electric vehicles, beneficial building electrification and battery storage systems

all impact both the energy mix and flexibility of the system. If there are unforeseen breakthroughs or complications, Platte River will need to adjust its resource mix in response.

8.5.1.2 Operational risks

There are operational risks that can occur in each plan once they are executed. It is easier to understand and quantify these operational risks with specific model runs. Their impact on portfolio viability is still significant and uncertain, but it is easier to evaluate the quantifiable tradeoffs.

- **Fuel and market price risk** – Portfolios are developed using the best estimates of future fuel and energy market prices. Past volatility suggests the potential for future volatility. Sensitivity runs modeling gas and power prices help establish each portfolio's susceptibility to this input and the consequences of future deviations from the expected value.

- **Regulatory risk on carbon accounting and emissions** – There continues to be a range of opinions on how carbon emissions will be regulated. The presence or absence of a carbon tax can impact the economics of a portfolio. Again, a sensitivity analysis can help quantify the financial impacts of a carbon tax.

- **Market evolution** – The implementation of a western energy market will impact different resources in different ways. Transmission congestion may erode the economics of remotely sited resources, while a robust energy market may impact price levels and volatility. If multiple utilities add renewable resources and transmission constraints emerge in moving power out of our region, there is a risk that excess renewable generation will depress market prices. This risk is more difficult to quantify than other operational risks, but Platte River continues to explore the potential range of impacts as the market develops.

The risks described above can impact a portfolio in different ways. One way to analyze their impacts is to conduct sensitivity analyses, where we change a driver or variable and measure the resulting impact on the portfolio. Section 8.5.2 discusses these analyses.

Because these risks and assumptions can change simultaneously, the combined effect can be large and drive us to change the portfolio mix. In section 8.5.3, we assess the combined risk of renewable cost increases and market price changes and review potential portfolio modifications to reduce this risk.

8.5.2 Sensitivity analyses

To understand the robustness of the modeled portfolios, the IRP process tests the portfolios under assumptions different from the base assumptions. In a sensitivity analysis, a single assumption or input is changed (gas prices, for example) and the portfolio is re-evaluated. Portfolios with stronger responses to the new assumption or input show greater risk. This analysis provides a deeper understanding of the tradeoff between cost and risk. For this IRP, Platte River performed sensitivity analyses on two main inputs: natural gas prices and renewable energy prices.

8.5.2.1 Natural gas prices

Natural gas prices can impact a portfolio in two ways. First, the price of this fuel directly influences regional market prices, which impacts the volume and cost or revenue of imports and exports to and from the Platte River system. Second, the portfolios continue to consume modest amounts of natural gas in the future, so changes in price directly impact the economics of the thermal generation. In this analysis, gas prices were tested at both higher and lower levels than the base assumption used in the portfolio development. Siemens, the supplier of the base gas price forecast, also supplied the high and low gas price trajectories, seen in Figure 39 earlier in this document, as well as associated market prices for each sensitivity.

8.5.2.2 High gas prices

Under this sensitivity, gas prices are 20% higher on average from 2030 to 2040. On a net present value basis, the portfolios' costs change very little, indicating the relatively small role of gas in future portfolios. On the low side, there is a 0.3% savings for the minimal new carbon portfolio while the additional new carbon portfolio has a cost increase of 1.4%. In general, higher gas prices increase the system operating cost due to higher fuel expenditures, but these increases are partially offset by higher sale revenues from higher market prices. Portfolios with more gas generation will see a net increase in cost, while portfolios with more must-sell renewable energy will benefit from the attractive market prices and see a slight savings.

8.5.2.3 Low gas prices

For this sensitivity, gas prices remain relatively flat starting in 2026. While the base case and high-price sensitivity show average escalation rates of 4.45% and 5.71% respectively through 2043, the low-price curve has a net gain of 0.2% by 2043, with a small decline during the 2030s. As expected, the results are the opposite of the high gas price sensitivity. Since this sensitivity sees a larger change to gas prices, with an average decrease of 54% relative to the base assumption, the change in net present value is more noticeable than in the high gas price sensitivity. The additional new carbon portfolio sees a cost savings of 5.1% and the optimal new carbon portfolio sees a savings of 3.6%. The minimal new carbon and no new carbon portfolios see modest savings of 0.6% and 0.8%, respectively.

8.5.2.4 Renewable energy prices

As discussed in section 3.4.3, renewable energy projects have seen significant cost increases in recent years.

In addition to the cost drivers of the projects themselves (including supply chain issues and competition for renewable resources), a second source of uncertainty around the cost of new renewable energy comes from Platte River's expected market participation. There is some possibility that the market will fail to launch as planned, or will launch with a different mix of participants, which would leave some projects exposed to higher transmission costs than might otherwise be expected in a market. Assuming the market does move forward as planned, there is still substantial uncertainty around the additional costs of transmission congestion, both under the existing portfolio and as regional portfolios evolve with more renewable energy concentrated at the optimal sites. Without a market, or with a market that is more congested than expected, the delivered cost of our renewable energy would rise.

For these reasons, Platte River ran a sensitivity analysis on renewable energy prices. We evaluated price increases for new wind and solar projects under each portfolio. Table 34 compares the base assumption to the higher price sensitivity for selected years. We did not test prices for energy storage and thermal generation because Platte River has not seen similar price volatility in those markets and their transmission congestion risk is much lower.

Wind cost (including transmission costs)			Solar cost	
	Base	High sensitivity	Base	High sensitivity
2030	32.85 $/MWh	40.99 $/MWh	30.01 $/MWh	40.37 $/MWh
2035	34.82 $/MWh	43.75 $/MWh	31.22 $/MWh	41.99 $/MWh
2040	36.87 $/MWh	46.67 $/MWh	32.43 $/MWh	43.62 $/MWh

Table 34. *Renewable PPA prices*

Because each portfolio adds a similar amount of renewable energy, the results across the portfolios are reasonably close. On a net present value basis, the smallest change is a $181 million increase for the additional new carbon portfolio, while the largest increase is $198 million for the carbon-imposed cost portfolio. The optimal new carbon portfolio has a cost increase of $190 million, which is about a 7% increase if renewable energy prices reach the level projected in the sensitivity.

The last two columns of Table 35 illustrate how the relative difference among portfolio costs changes from the base case to the sensitivity case. These intra portfolio cost comparisons are shown relative to the lowest cost portfolio referred to as the additional new carbon portfolio (labeled as "ANC" in the table below). For the base case runs, the cost of the no new carbon portfolio is 93.6% higher relative to the additional new carbon portfolio, while the sensitivity case is 88.0% higher. There is very little change in the relative cost differences for the remaining portfolios.

	Base and sensitivity comparison			Intra portfolio cost comparison	
Portfolio	Base case	Sensitivity: high RE	% change	Base case: % diff vs. ANC	Sensitivity: % diff vs. ANC
No new carbon	$5,344,991	5,531,559	3.5%	93.6%	88.0%
Minimal new carbon	$3,372,202	3,559,856	5.6%	22.1%	21.0%
Carbon-imposed cost	$2,779,024	2,976,911	7.1%	0.7%	1.2%
Optimal new carbon	$2,772,407	2,962,228	6.8%	0.4%	0.7%
Additional new carbon	$2,761,036	2,941,920	6.6%	0.0%	0.0%

Table 35. *Renewable PPA prices*

8.5.2.5 Sensitivity analysis summary

While uncertainty about some model inputs is unavoidable, quantifying the impacts of those uncertainties can help manage the risks associated with them. Table 36 compares the net present value costs across the base case assumptions and the sensitivities described above.

Net present values	Base	High gas and power	Low gas and power	High renewable energy prices
No new carbon	$5,344,991	$5,343,332	$5,304,721	$5,531,559
Minimal new carbon	$3,372,202	$3,363,500	$3,352,897	$3,559,856
Carbon-imposed cost	$2,779,024	$2,783,634	$2,724,507	$2,976,911
Optimal new carbon	$2,772,407	$2,794,671	$2,672,710	$2,962,228
Additional new carbon	$2,761,036	$2,800,210	$2,620,375	$2,941,920

Table 36. *Net present value cost comparison with gas prices and renewable prices*

At a high level, the no new carbon portfolio and the minimal new carbon portfolio are uncompetitive in every case. Table 37 converts the net present value costs into rankings for the base case and each sensitivity, with the result that the no new carbon portfolio is last under every assumption tested and the minimal new carbon portfolio is fourth under every assumption tested.

Net present value rankings	Base	High gas and power	Low gas and power	High renewable energy prices	Average
No new carbon	5	5	5	5	5.0
Minimal new carbon	4	4	4	4	4.0
Carbon-imposed cost	3	1	3	3	2.5
Optimal new carbon	2	2	2	2	2.0
Additional new carbon	1	3	1	1	1.5

Table 37. *Portfolio ranking with sensitivity analysis*

The top three portfolios are more competitive, and their relative value depends on the future trajectory of prices and the impacts of CO2 emissions. The optimal new carbon portfolio proves to be robust, with a second-place ranking in every run. This portfolio is, on average, only 0.9% more expensive than the best portfolio in any given sensitivity (including the base case). While some portfolios may perform better in a specific set of circumstances, the optimal new carbon portfolio performs well across the range of outcomes and proves to be a cost-effective and robust solution.

8.5.3 Excess renewable and market participation risk

With a substantial increase in intermittent renewable resources, Platte River faces an increasing risk from the mismatch in timing between customer demand and when renewable generation is available. Some of the mismatch can be managed with energy storage, but it would be impractical to balance the entire renewable energy portfolio using current battery storage technology. When there is insufficient renewable energy, Platte River can purchase energy from the market, withdraw stored energy, or rely on thermal generation to fill the gap. When there is too much energy, Platte River will store the excess (after meeting its load) and must sell any additional renewable energy into the market or curtail the resource.

Starting in 2030, Platte River anticipates having about 10% to 35% surplus energy on an annual basis. Of that excess, about 75% is expected to be sold, while the remainder will be curtailed due to limited energy demand and constrained transmission systems.

Because renewable energy contracts are structured as take-or-pay, Platte River must pay the full price of the PPA whether we take delivery of the energy or not. In this context, Platte River will sell excess renewable energy into the market if the market price is greater than $0 but will incur a loss if the market price is below the PPA price. Therefore, the economic value of the surplus renewable energy depends on the cost of the PPA relative to the market price of the energy at the time of the excess energy.

Given that the entire region is adding wind and solar resources, we anticipate market prices to be lowest when we have surplus renewable energy. Figure 59 illustrates the average expected monthly power prices in 2031 and monthly excess renewable energy as a percentage of the total monthly energy required by Platte River customers.

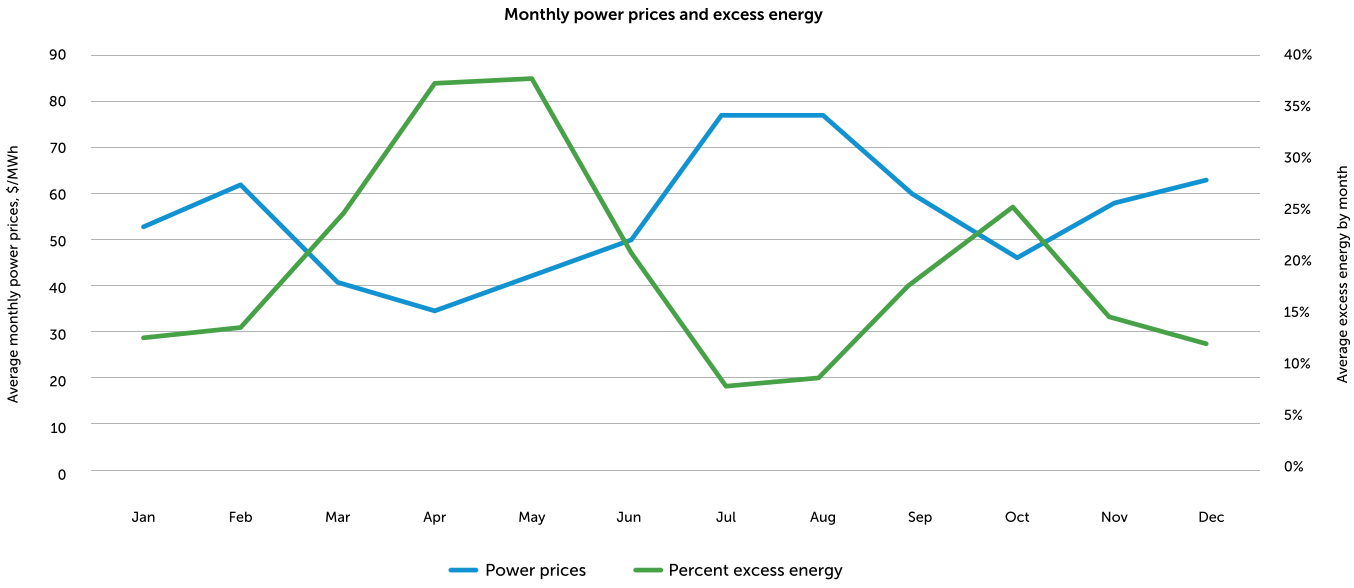


Figure 59. *Monthly power prices and excess energy*

The blue line shows average monthly prices, while the green line shows excess energy as a percent. The average prices are lowest in April and May, when the excess energy is above 35% of Platte River's needs. Excess energy is relatively low in higher-priced months of summer and winter.

To better understand the supply-demand balance and assess energy risk, Platte River staff analyzed expected hourly operations during the year 2031 using 24 historical hourly weather patterns for the recommended portfolio, which called for adding 400 MW of new wind by 2030. The diversity of weather data allows a broader quantification of the risk across multiple weather years, rather than relying on a single representative year.

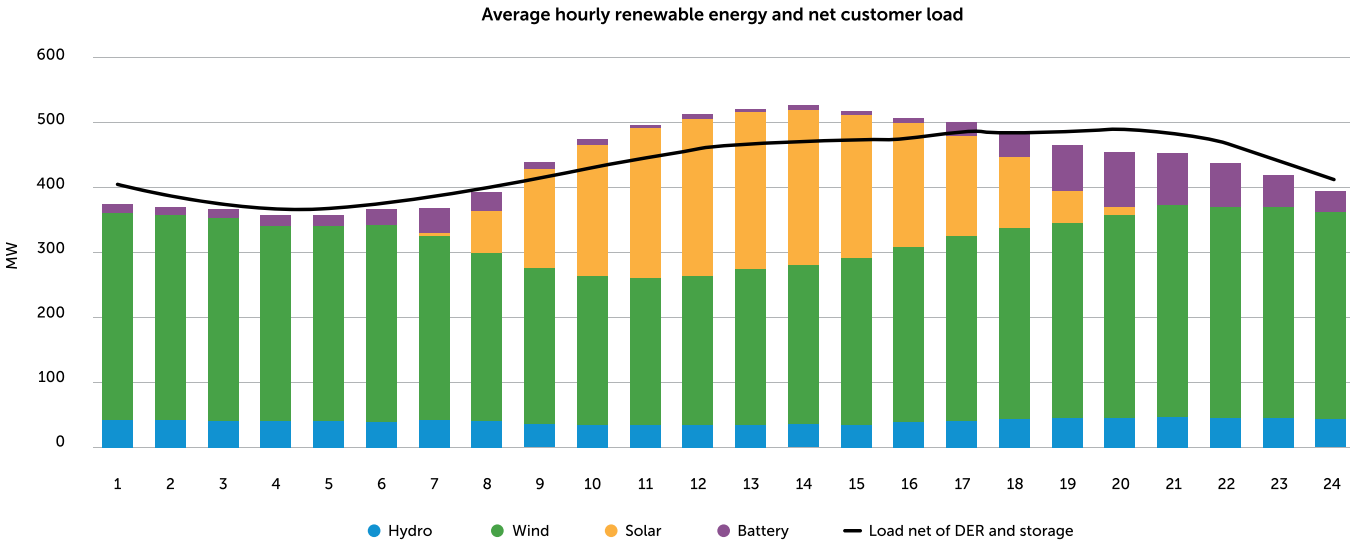


Figure 60. *Average hourly renewable energy and net customer load*

Figure 60 summarizes the average excess megawatts by hour of day and month of the year. During the day, we have excess energy in midday when solar output is high. However, during the morning and evening hours, when the load is ramping up, the Platte River system needs dispatchable capacity and market access.

Balancing this excess renewable energy with the need for sufficient energy during high demand is one of the primary tasks of this IRP. Platte River developed the recommended portfolio with 400 MW of new wind, with the wind power purchase price around $32/MWh, and market prices in the 2030s around $50/MWh, making excess energy revenue positive. However, if market prices continue to drop with the addition of renewable resources in the region and demand for renewable energy continuing to rise, the cost of renewable energy will increase. In this scenario, the risk is not only the limited value from excess renewable energy but also market price volatility.

Platte River will need to consider these risks before fully implementing the recommended plan. This exposure to factors outside Platte River's control makes managing the portfolio's risk a critical part of the execution phase. Platte River will continue to monitor commodity prices (like gas), market power price forecasts, and the cost of renewable energy to refine and rebalance the plan as necessary to meet our financial sustainability pillar. If necessary, we can adjust the renewable mix or storage capacity to mitigate risk if it is cost-effective.

09 Action plan

Platte River will continue to work toward the RDP goal over the next five years. Platte River plans to retire coal generation, add more renewable generation, add energy storage, add a VPP, join a full organized energy market and add efficient dispatchable thermal generation to complement renewable intermittency.
We expect to carry out the following specific activities.

9.1 2024-2028: Execution phase

Resource plan component	Anticipated actions	Approximate timing	Key risks that may impact actions
Renewable energy acquisition	Contract for new 107 MW solar from the 2022 solar RFP	2024	Execution risks (section 7.5.1.1) • Cost escalation • Siting complications • Technology evolution Operational risks (section 7.5.1.2) • Market evolution
	Contract for new 250 MW wind from the 2023 wind RFP	2024	
	Begin commercial operation of 150 MW Black Hollow Solar project	2025	
	Begin commercial operation of a 130 MW solar project	2027	
Dispatchable capacity (reliability)	Contract to add up to 20 MW of distributed energy storage from 2021 solar and storage RFP	2024	Execution risks (section 7.5.1.1) • Cost escalation • Siting complications • Technology evolution • DER adoption rates Operational risks (section 7.5.1.2) • Fuel and market price risk • Regulatory risk on carbon accounting and emissions • Market evolution
	Issue RFP for four-hour battery energy storage system	2024	
	Review results from all-dispatchable-resource RFP	2024	
	Begin adding up to 200 MW of dispatchable thermal generation resources. Major activities include: • Apply for air and land use permits • Identify actions related to ordering some long lead time equipment, especially related to power transmission • Develop initial project design and enlist engineering, procurement and construction contractor	2024	

Resource plan component	Anticipated actions	Approximate timing	Key risks that may impact actions
Dispatchable capacity (reliability)	Issue RFP for systems and services to support development of a VPP that can provide dispatchable capacity for Platte River and the owner communities	2024	Execution risks (section 7.5.1.1) • Cost escalation • Siting complications • Technology evolution • DER adoption rates Operational risks (section 7.5.1.2) • Fuel and market price risk • Regulatory risk on carbon accounting and emissions • Market evolution
	Issue RFP for dispatchable thermal resource development if the 2024 all dispatchable resource RFP does not result in an acceptable project	2025	
	With our owner's engineer and contractor, complete plant design for new resource and balance of plant services	2025	
	Complete battery energy storage system agreements	2025	
	Issue RFP for additional energy storage system	2025	
	Plan VPP systems design and architecture	2025	
	Start work on a demonstration project for long-duration energy storage system	2025	
	Build VPP systems, system integrations and develop key functionality	2026	
	Begin commercial operation of up to 25 MW of distributed energy storage from 2021 solar RFP	2026	
	Launch VPP with 7 MW dispatchable capacity	2027	

Resource plan component	Anticipated actions	Approximate timing	Key risks that may impact actions
Customer programs	Plan and develop VPP customer programs	2025	Execution risks (section 7.5.1.1) • Technology evolution • DER adoption rates Operational risks (section 7.5.1.2) • Market evolution VPP system integration Third-party DER device aggregators
	Launch VPP customer programs	2026	
Community engagement	Continue public education campaign to engage communities, customers in the energy transition	2024-2028	
	Support renewable energy project acquisitions and engage communities through groundbreaking events, ribbon-cutting ceremonies	2025-2028	
Transmission	Complete construction and energize the 230-kV interconnection switching station (Severance substation) to interconnect new renewable resources	2025	Execution risks (section 7.5.1.1) • Cost escalation • Siting complications Operational risks (section 7.5.1.2) • Market evolution
Markets	Begin training staff to prepare for SPP RTO West market entry	2024	Operational risks (section 7.5.1.2) • Market evolution System integration Market tariff and resource adequacy
	Screen and select market interface software	2024	
	Begin testing operations in SPP RTO West	2025	
	Join SPP RTO West market operations on April 1	2026	

Resource plan component	Anticipated actions	Approximate timing	Key risks that may impact actions
Other enabling activities	Finalize and file a just transition plan with the state of Colorado for workers affected by Rawhide Unit 1's closure	2024	Interest rates
	Working alongside other owners, retire Craig Unit 1 (of which Platte River owns a 77 MW share)	2025	
	Initiate 2028 IRP process	2026	
	Issue bonds to fund capital investments	2025-2026	
	Continue 2028 IRP process including: • Receive studies from external consultants • Execute community engagement activities to educate public, collect stakeholder feedback • Conduct modeling and analyze portfolios • Compile draft report	2027	

9.1 2024-2028: Execution phase

Resource plan component	Anticipated actions	Approximate timing	Key risks that may impact actions
Renewable energy acquisition	Begin commercial operation of new wind generation	2028	Execution risks (section 7.5.1.1) • Cost escalation • Siting complications • Technology evolution Operational risks (section 7.5.1.2) • Market evolution
Dispatchable capacity (reliability)	Testing, commissioning, and operation of new dispatchable thermal resource	2028	Execution risks (section 7.5.1.1) • Cost escalation • Siting complications • Technology evolution • DER adoption rates Operational risks (section 7.5.1.2) • Fuel and market price risk • Regulatory risk on carbon accounting and emissions • Market evolution
	Begin commercial operation of energy storage systems (for which RFP was issued in 2025)	2028	
	Grow VPP dispatchable capacity to 15 MW and develop market dispatch capabilities	2029	
	Grow VPP dispatchable capacity to 24 MW and develop distribution dispatch capabilities	2029	
	Develop a mobile app to help customers and distribution utilities connect with Platte River's system	2028-2030	
Community engagement	Support mobile app deployment with communications and community activations	2028-2030	
	Continue public education campaign to engage communities, customers in the energy transition	2028-2030	

Resource plan component	Anticipated actions	Approximate timing	Key risks that may impact actions
Other enabling activities	Implement the Just Transition Plan	2024-2030	
	Working alongside other owners, retire Craig Unit 2 (of which Platte River owns a 74 MW share)	2028	
	Seek approval from Platte River Board for 2028 IRP; file with WAPA	2028	
	Retire Rawhide Unit 1 by December 31	2029	

10 Appendices

Appendix A: IRP checklist for WAPA

Document section	Requirement	Included in this IRP	Section number
IRP design, IRP study results **Power markets** **Energy efficiency** **DER integration, flexible DERs and the virtual power plant** **IRP portfolios**	Does the IRP evaluate the full range of alternatives for new energy resources, including: • new generating capacity? • power purchases? • energy conservation and efficiency? • cogeneration and district heating/cooling applications? • renewable energy resources?	✓	6.3.3, 6.3.4, 6.3.5, 6.3.6, 6.3.7 7.1, 7.4, 8.2, 8.3 4.1.5, 6.3.4, 6.3.5, 5.3.2 5.3.1 7.4, 8.2, 8.3
Planning for a reliable future power supply	Does the IRP provide adequate and reliable service to the customer's electric consumers?	✓	7.3
IRP design, IRP study results	Does the IRP take into account the necessary features for system operation?	✓	4.2.1, 7.3, 8.5
DER integration, flexible DERs and the virtual power plant	Does the IRP take into account the ability to verify energy savings achieved through energy efficiency?	✓	5.3
DER integration, flexible DERs and the virtual power plant	Does the IRP take into account the projected durability of such savings measured over time?	✓	5.3
Load forecast methodology and data	Does the IRP treat demand and supply resources on a consistent and integrated basis?	✓	5.3, 5.4.1, 5.4.2
Planning for a reliable future power supply	Does the IRP consider electrical energy resource needs?	✓	7.3
Energy and capacity planning, DER integration, flexible DERs and the virtual power plant, supply side generation resources, IRP portfolios	Does the IRP identify and compare resource options?	✓	4.1.2, 5.3, 6.3, 7.4, 7.5

Document section	Requirement	Included in this IRP	Section number
Comparative analysis of portfolios, portfolio recommendation, risk assessment and sensitivity analysis	Does the IRP clearly demonstrate that decisions were based on a reasonable analysis of the options?	✓	8.3, 8.4, 8.5
Action plan	Does the IRP include an action plan describing specific actions the customer will take to implement the IRP?	✓	9
Action plan	Does the IRP list the time period that the action plan covers?	✓	9
Action plan	Does the IRP include an action plan summary consisting of: • Actions the customer expects to take in accomplishing the goals identified in the IRP? • Milestones to evaluate accomplishment of those actions during implementation? • Estimated energy and capacity benefits for each action planned?	✓	9
Portfolio CO2 emissions	Does the IRP, to the extent practicable, minimize adverse environmental effects of new resource acquisitions and document these efforts?	✓	8.3.2 with additional text from environmental
Portfolio CO2 emissions	Does the IRP include a qualitative analysis of environmental effects in a summary format?	✓	8.3.2
Stakeholder engagement process	Does the IRP provide ample opportunity for full public participation in preparing and developing the IRP?	✓	3.7

Document section	Requirement	Included in this IRP	Section number
Stakeholder engagement process	Does the IRP include a brief description of public involvement activities?	✓	3.7
Board resolution to approve the 2024 IRP	Does the IRP document that each MBA member approved the IRP, confirming that all requirements have been met?	✓	Appendix C
Board resolution to approve the 2024 IRP	Does the IRP contain the signature of each MBA member's responsible official, or document passage of an approval resolution by the appropriate governing body?	✓	Appendix C
Electricity demand	Does the IRP contain a statement that the customer conducted load forecasting, including specific data?	✓	5.1-5.4
Planning for a reliable future power supply, portfolio CO2 emissions, DER integration, flexible DERs and the virtual power plant, IRP portfolios	Does the IRP contain a brief description of measurement strategies for identified options to determine whether the IRP's objectives are being met?	✓	7.3.2.2, 8.3.2, 5.3
Planning for a reliable future power supply, portfolio CO2 emissions, DER integration, flexible DERs and the virtual power plant, IRP portfolios	Does the IRP identify a baseline from which the customer will measure the benefits of IRP implementation?	✓	7.3.2.2, 8.3, 5.3
	Does the IRP specify the responsibilities and participation levels of individual members of the MBA and the MBA?	N/A	

Appendix B: 2024 Just Transition Plan

Platte River Power Authority

Estes Park • Fort Collins • Longmont • Loveland

2024 JUST TRANSITION PLAN

BACKGROUND

Platte River Power Authority (Platte River) is a not-for-profit, community-owned public power generation and transmission utility that provides safe, reliable, environmentally responsible and financially sustainable energy and services to the communities of Estes Park, Fort Collins, Longmont and Loveland, Colorado, for delivery to their distribution utility customers. Platte River owns and operates Rawhide Energy Station (Rawhide), located roughly ten miles north of Wellington, Colorado. Rawhide consists of one 280 megawatt (MW) capacity coal fired boiler (Unit 1) and five natural gas-fired combustion turbines with a combined 388 MW capacity (Units A, B, C, D and F) that support peak power demand. Additionally, Rawhide also has 52 MW of solar and a 2 MW-hour battery storage system.

Platte River, like other Colorado utilities, is transforming how it generates and delivers energy. In 2018, Platte River's board of directors (the board) approved the Resource Diversification Policy (RDP), which directed Platte River to proactively work toward achieving a 100% noncarbon energy mix by 2030 while maintaining Platte River's three foundational pillars of providing reliable, environmentally responsible and financially sustainable electricity and services. A significant milestone on the journey to 100% noncarbon energy is its commitment to retire Unit 1 by the end of 2029. This commitment is reflected in its current Integrated Resource Plan (2024 IRP) and in its Clean Energy Plan, which was submitted to the state of Colorado in 2022. This commitment is also included in Resolution 08-24 which formally announces Unit 1's accelerated retirement as part of the 2024 IRP. With Platte River's commitment to retiring Unit 1, the utility will submit this document – Platte River's Just Transition Plan – to the Colorado Office of Just Transition within 30 days of Platte River's board of directors approving Resolution 08-24 and the 2024 IRP.

Platte River is not just transforming its energy mix. Embracing the future will require Platte River to change and adapt as an organization. Platte River entered the Southwest Power Pool (SPP) Western Energy Imbalance Service market in 2023 and will enter SPP's Regional Transmission Organization –West (RTO–West) in April 2026, which is one of the key advancements identified to further the RDP. To support entering RTO–West, Platte River is initiating a strategic workforce analysis to identify the necessary changes to its people, processes, and technologies.

Platte River's board passed Resolution 08-2020 (Workforce Resolution) in 2020, when Platte River announced Unit 1's retirement. The Workforce Resolution planned six principles that Platte River is committed to follow when implementing its transition plan. These principles are:

- Transparency
- Workforce Planning
- Workforce Opportunities
- Workforce Training
- Retention Strategies
- Transition Support

Platte River, through its Workforce Resolution and Just Transition Plan, will continue to demonstrate its unwavering commitment to support and retain employees who wish to remain with the organization through Unit 1's retirement and its transition to a clean energy future.

PLATTE RIVER AT A GLANCE

Platte River Power Authority is a not-for-profit, community-owned public power utility that generates and delivers safe, reliable, environmentally responsible and financially sustainable energy and services to Estes Park, Fort Collins, Longmont and Loveland, Colorado, for delivery to their utility customers.

Headquarters

Fort Collins, Colorado

General manager/CEO

Jason Frisbie

Began operations

1973

Staff

268

2023 peak demand of owner communities

680 MW

2023 deliveries of energy

4,506,208 MWh

2023 deliveries of energy to owner communities

3,161,533 MWh

Transmission system

Platte River has equipment in 27 substations, 263 miles of wholly owned and operated high-voltage lines, and 522 miles of high-voltage lines jointly owned with other utilities.

PLATTE RIVER POWER AUTHORITY'S 2024 JUST TRANSITION PLAN

As required by House Bill 19-1314 and to further its commitment to Unit 1's retirement and the 100% noncarbon goal of its RDP, Platte River submits this Just Transition Plan to the Colorado Office of Just Transition. Platte River views this Just Transition Plan as a living document and anticipates that it will revise both the Just Transition Plan and its IRP as Unit 1's Dec. 31, 2029 retirement date nears. Platte River's Just Transition Plan follows the six principles of its Workforce Resolution and supports its ongoing commitment to retain employees through the energy transition and to avoid involuntary separations (layoffs) due to Unit 1's retirement.

MARKET
09
22

PRINCIPLE 1: TRANSPARENCY

Platte River management will make every effort to communicate impacts proactively and transparently to employees as decisions are made, including the timelines of planned events.

To implement this principle, Platte River consistently updates both Rawhide and Headquarters staff on the transition plan, including at plant and business meetings and through updates to Platte River's board. Platte River also discusses the upcoming transition, including its commitment to retain employees after Unit 1's retirement, with external candidates as part of the interview and hiring process. Platte River offers RTO–West training to the whole organization and will provide the results of its upcoming gap analysis to internal stakeholders so that each department can evaluate the changes to people, processes, and technology that will be needed in 2026 and beyond. Platte River also plans to provide this Just Transition Plan and the 2024 IRP to all employees through multiple channels and opportunities for employee to submit questions, concerns, and feedback on Platte River's transition.

Platte River's Just Transition Plan is led by a cross-functional team including representatives from power generation, operations, human resources, communications, and legal affairs and is sponsored by Platte River's Chief Operating Officer – Generation, Transmission and Markets. This cross-functional team currently plans additional outreach and communication to staff on workforce planning and workforce transition to accompany the Just Transition Plan and 2024 IRP. The cross-functional team is guided by the RDP, the Workforce Resolution and Platte River's Strategic Plan as it deploys Platte River's strategic workforce planning tools to further those goals and establish ongoing dialogue on how to best meet them in a just and transparent way.

PRINCIPLE 2: WORKFORCE PLANNING

Platte River management will continue to evaluate and identify workforce needs and to communicate its needs to staff.

To implement this principle, Platte River's leadership, partnering with its human resources department, is currently using strategic planning, data modeling, and other workforce planning tools to anticipate Platte River's future workforce needs. While this modeling is an imperfect science, Platte River is committed to using the best tools and data available, and to continually updating its models as Unit 1's retirement nears and Platte River's future needs become clearer.

It is important to note that Platte River is growing as an organization, even as Unit 1 retires. It will need additional staff in many functional areas to meet the RDP and the Strategic Plan, including in power marketing, power delivery, compliance, information technology, and substation maintenance. Platte River has determined how future vacancies will provide opportunities to transition Rawhide employees to other positions in the organization.

Platte River's internal modeling also shows that its workforce transition will largely be driven by natural attrition and retirement, not through layoffs. Many current Platte River employees have more than 25 years of service. Historically, Platte River attrition has been low amongst its longest-tenured employees, a trend that it anticipates may change as more staff members reach retirement age. Platte River, like other employers, has experienced increased attrition and volatility amongst its newer employees, a trend that it anticipates will not change between now and 2029.

Figure 1 and Figure 2 show the general trends that Platte River has modeled and observed in attrition by years of service, both for the organization as a whole and for Rawhide.

Figure 1: Platte River Attrition by Years of Service

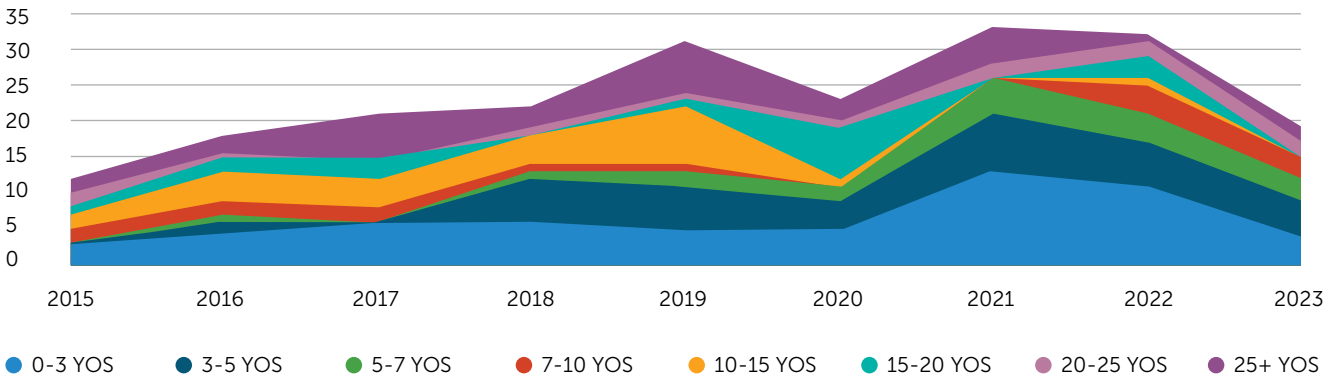


Figure 2: Rawhide Attrition by Years of Service

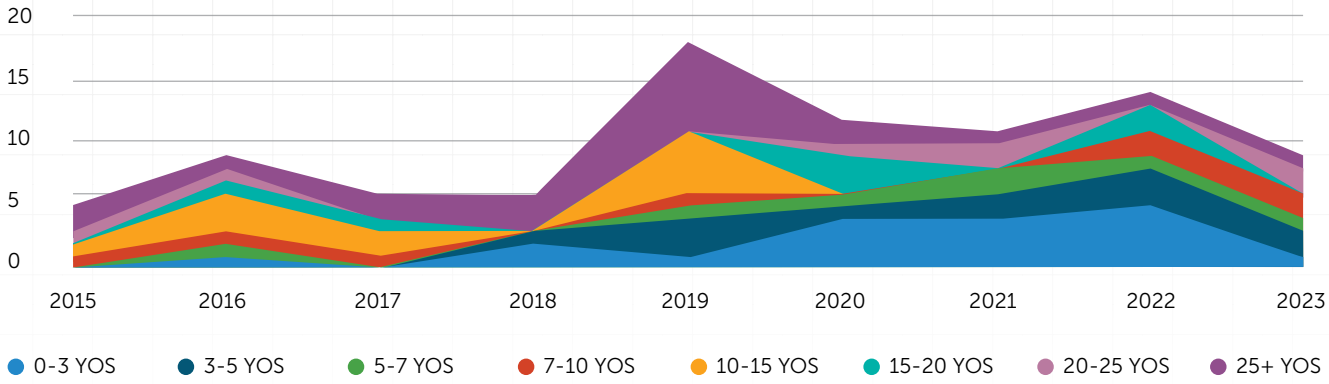


Figure 3 and Figure 4 show the historical reasons for attrition, both for Platte River as a whole and specifically for Rawhide. Retirement drives greater attrition at Rawhide than at Platte River as a whole, another trend that it anticipates will be stable through 2029. Platte River's projections for natural attrition show that it will be understaffed at Rawhide in the latter part of the decade (for example, from 2027 to 2029).

Figure 3: Platte River Attrition by Reason

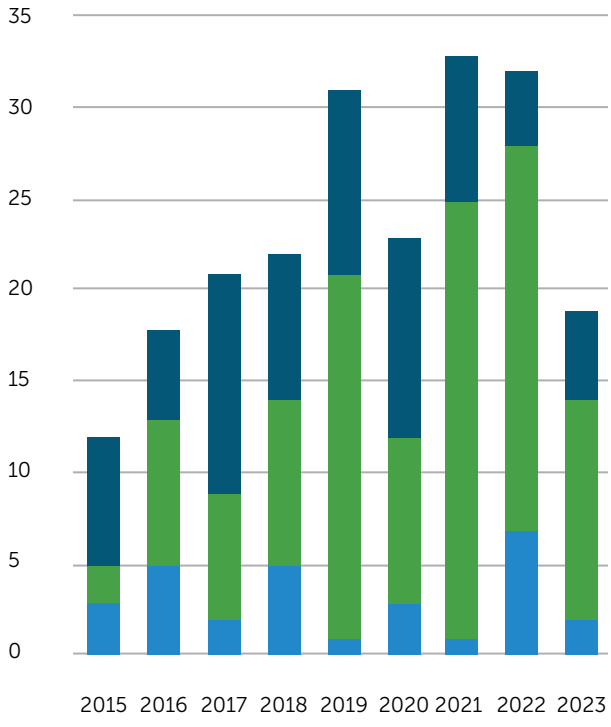
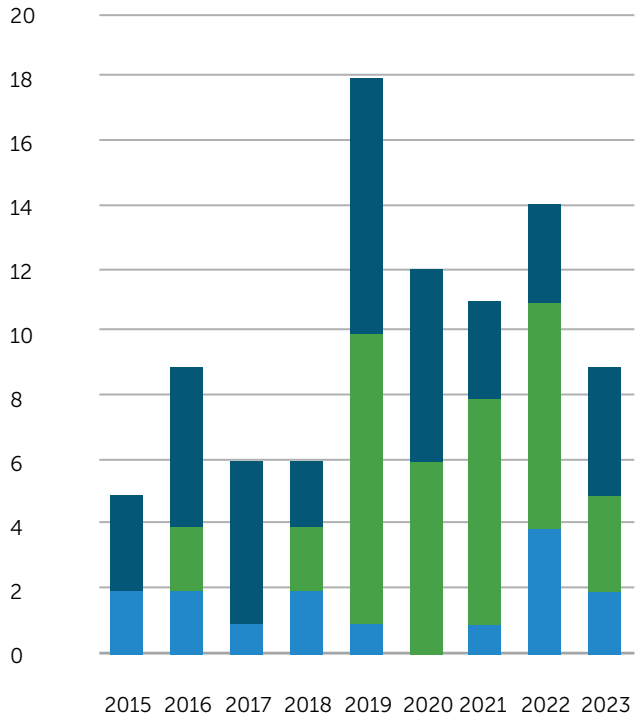
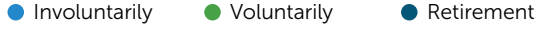


Figure 4: Rawhide Attrition by Reason





Platte River projects that it will need to transition approximately 25-30 Rawhide employees at Unit 1's retirement if it backfills vacancies that arise due to retirements or other natural attrition. See Table 1. But Platte River may also fill in for natural attrition with contract labor as Unit 1's retirement date nears. Platte River will be able to better estimate the exact number of employees to transition in future years, as it clarifies the number of employees needed to support the remaining generation at Rawhide and its other departments.

Table 1. Projected headcount and the number of employees to transition to Rawhide

Department	Current headcount As of Jan. 1, 2024	Target headcount At retirement Dec. 2029	Target headcount Post 2030	Employees to transition
Plant operations	31	22	10-15	7-12
Mechanical maintenance	14	8	6	2
Instrumentation and electrical	12	12	4	8
Fuel handling / facilities	12	5	4	1
Engineering	10	7	2	5
Lab	2	2	2	0
CAD	1	1	0	1

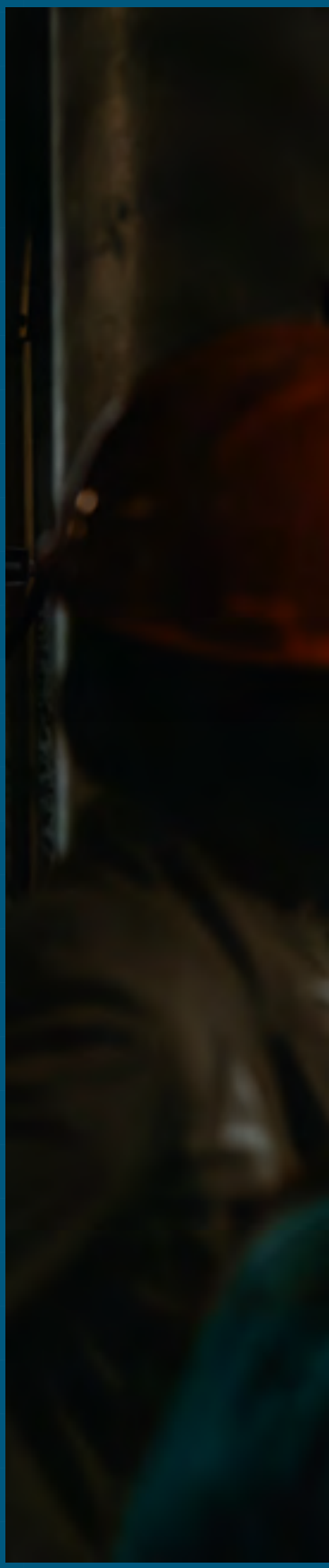
Current headcount
This is the number of employees at Rawhide to support Unit 1 as of May 2022. It does not include contract workers, which are managed by the vendors who employ them.

Target headcount (at retirement)
This is the estimated number of employees needed to safely operate Rawhide Unit 1 and the existing combustion turbines.

Target headcount (post-2030)
This represents the number of employees that it estimates are needed to run the existing gas combustion turbines at Rawhide after Unit 1 retires. These estimates may be updated in future filings.

Employees to transition
This number represents employees whose existing jobs may be eliminated due to Unit 1's retirement. Therefore, this is the number of employees to retrain, transfer within other business areas, or otherwise transition as part of the Just Transition Plan.

Platte River is committed to finding opportunities for each of these employees to remain with the organization, if desired. Platte River intends to honor its promise that no employees will be laid off or involuntarily separated solely due to Unit 1's retirement and the energy transition. How Platte River intends to meet this commitment is discussed further in the principles below.



ANGER

PRINCIPLE 3: WORKFORCE OPPORTUNITIES

Platte River management will prioritize internal staff for workforce opportunities where Rawhide employees have relevant qualifications and experience.

To implement this principle, Platte River is identifying growth opportunities and projected work for existing employees to transition at Rawhide and at Headquarters. The main areas where Platte River sees these opportunities are:

- Power markets and marketing desks (both transmission and generation)
- Compliance
- Information Technology
- Facilities
- Substations

Each of these areas is anticipated to grow between now and 2029 due to the energy transition and Platte River's entry into RTO–West. Platte River encourages high-performing employees to reach out to their supervisors (either as part of a scheduled performance discussion or at other times) to discuss potential transition plans and opportunities. Platte River advertises all vacancies to internal employees and seeks to prioritize internal applicants for many of its open positions.

Platte River plans additional formal efforts in the upcoming years to highlight potential growth opportunities within the organization and support employee advancement and retention. These efforts include an internal "career fair" (expected in 2026) to showcase potential opportunities within the organization and to further the dialogue between departments that may lose staff and departments that need additional employees. Platte River also plans a "shadowing" program between Rawhide and headquarters so that Rawhide employees may learn more about headquarters positions that may be available, and the knowledge, skills, or abilities needed for those roles.

No later than year end 2028, Platte River plans to start formal interviews with employees to have more in-depth discussions about their goals and determine how they may align with future roles. These formal interviews will also help Platte River determine what training, education, or other support might be needed to successfully transition employees into future growth roles.

PRINCIPLE 4: WORKFORCE TRAINING

Platte River management will provide workforce training for Rawhide employees when appropriate to allow them to successfully transition into new roles.

To implement this principle, Platte River will use the career fair, shadowing, and interview programs described above to engage with employees on how Platte River can best help employees meet their career goals. Platte River intends to capture and analyze information learned through annual employee evaluation processes and other discussions to identify employment trends and skill gaps and to formalize training programs that are specific to the identified skill needs post-2029.

Platte River understands that training and education may be a large component of the workforce transition, particularly for employees contemplating career changes. Platte River currently has a tuition reimbursement program for employees who want to increase skills. This program is already in use with a current Rawhide employee taking courses in information technology. Platte River anticipates this program will grow significantly as it identifies skill gaps and helps employees chart career paths. Platte River is working with its staff to increase transferable skills (like computer literacy) in its current workforce. Platte River will also explore partnerships with local educational institutions in northern Colorado and southern Wyoming.These partnerships may include formal training programs tailored to the Rawhide transition or a continuation of the current tuition reimbursement program, depending on employee and Platte River needs.

PRINCIPLE 5: RETENTION STRATEGIES

Platte River management will evaluate, design, and implement employee retention strategies to ensure Rawhide Unit 1 continues to provide safe, reliable and financially responsible energy to its owner communities until its closure date.

Platte River is committed to implementing this principle for transitioning Rawhide employees. But employee retention is not just a concern as part of the energy transition or the Just Transition Plan. Platte River seeks to be a leading employer to drive retention for all employees, at both Rawhide and headquarters, and has made many recent changes to its compensation and total employee rewards programs to support employee retention. These changes include industry-leading total rewards and compensation packages, such as:

- Platte River family leave program (providing 12 weeks fully paid family leave),
- Platte River's compensation philosophy is inclusive of a compensation study which uses a market-leading pay above the 50th percentile in 2024,
- Platte River's employee-focused benefits program, and
- Hybrid and remote work available for certain roles.

Platte River is exploring other options for retention at Rawhide up to transition, including retention bonus programs and incentives for advance retirement planning in the years leading up to Unit 1's closure. Platte River will work with its employees to evaluate and carefully implement these strategies in a way that supports the goals of continued operational excellence at Rawhide, an orderly and well planned closure, and employee transition to new roles.

PRINCIPLE 6: TRANSITION SUPPORT

For those employees whose paths lead away from Platte River, Platte River management will seek to ease their transitions with placement support and incentives, where appropriate.

When discussing this principle, it is important to reiterate that current projections show few, if any, non-voluntary transitions due to the retirement of Rawhide Unit 1. As discussed in the first five principles, above, Platte River is committed to retaining its workforce and anticipates finding roles for Rawhide employees who want to transition to new roles after 2029. Platte River does not anticipate layoffs or other mass transitions. Platte River's Just Transition Plan supports an individualized and career-focused approach for each employee affected by Unit 1's closure.

Should any non-voluntary transitions be needed in the future due to Unit 1's retirement, Platte River is committed to supporting those employees as it supports those who transition voluntarily. Efforts will be deployed through career path discussions and ongoing training and education opportunities like those provided to employees transitioning to internal Platte River roles. Platte River also provides an employee assistance program, which is available to current employees contemplating career changes and transitions. This program may include counseling support as well as legal or financial advice to assist employees in making life changes.

CONCLUSION

Platte River is committed to a just transition and to retaining its staff and culture of operational excellence. This document will be updated as its workforce plans evolve. Platte River will remain committed to the principles outlined by its board and management to demonstrate their unwavering support to the Platte River employees that safely and reliably operate Unit 1, its highest-performing and most cost-effective resource. Platte River looks forward to working with its staff, management, and the Office of Just Transition to responsibly move toward its energy future.

Appendix C: Board resolution for 2024 IRP approval

RESOLUTION NO. 07-24

Background

A. Platte River Power Authority (Platte River) was formed to provide electric generation and transmission services to its owner communities.

B. Platte River is obligated by contract to serve the owner communities' wholesale electrical capacity and energy needs through 2060.

C. Platte River and its owner communities collaborate to conduct supply-side and demand-side planning.

D. Platte River uses integrated resource planning to support its development of a resource portfolio consistent with its three foundational pillars of reliability, environmental responsibility and financial sustainability.

E. In 2018, the board of directors (board) adopted the Resource Diversification Policy, which directs Platte River's general manager/CEO to proactively work toward the goal of reaching a 100% non-carbon resource mix by 2030, while maintaining Platte River's three pillars of providing reliable, environmentally responsible and financially sustainable electricity and services.

F. By law and to remain eligible for federal hydropower allocations, Platte River must submit a formal integrated resource plan (IRP) to the Western Area Power Administration every five years. Given the challenges of quickly advancing the board's Resource Diversification Policy goals, compounded by rapid evolution of utility technology, the board encouraged staff to accelerate its formal IRP development process. Platte River staff completed and submitted its most recent IRP in 2020, and shared with the board an informal update to the IRP inputs and assumptions in 2022.

G. Platte River staff, collaborating with industry experts, has worked over the past 18 months to develop the 2024 IRP with updated studies, assumptions, technology advancements, and modeling inputs. Platte River supported community engagement through numerous in-person and virtual meetings, cataloguing and responding to stakeholder questions, and a dedicated internet microsite. Staff shared background information for the 2024 IRP with the board in April 2024 and presented a full draft of the 2024 IRP at the May 2024 board meeting.

H. The 2024 IRP reflects existing and potential future resources based on current information, technology and system capabilities and recognizes these and other factors will continue to evolve.

I. Staff recommends selection of the 2024 IRP's optimal new carbon portfolio to establish a new baseline for planning, budgetary and ratemaking purposes.

J. The optimal carbon portfolio in the 2024 IRP provides a path for Platte River to reduce its carbon emissions by more than 90% from 2005 levels while maintaining reliability and financial sustainability, and is therefore consistent with the Resource Diversification Policy and surpasses Colorado legislative goals for greenhouse gas reductions.

K. Staff expects to prepare an updated IRP by 2028, while continuing to communicate transparently and foster public engagement in Platte River's long-term resource planning activities.

L. The board intends that when it approves the Just Transition Plan (Resolution 08-24) for the closure of Rawhide Unit 1, the Just Transition Plan will become part of the 2024 IRP.

Resolution

The board of directors of Platte River Power Authority therefore resolves that:

1. The 2024 IRP, as contained in the July 2024 meeting packet, is approved, and
2. Staff's recommendation to select the optimal new carbon portfolio as Platte River's new baseline for planning, budgetary and ratemaking purposes is accepted, and
3. When the board approves Platte River's Just Transition Plan for Rawhide Unit 1, the Just Transition Plan becomes part of the 2024 IRP.

AS WITNESS, I have signed my name as Secretary and have affixed the corporate seal of the Platte River Power Authority this 25 day of July 2024.

Secretary

Adopted: July 25, 2024
Vote: 6-0

Platte River
Power Authority

Estes Park • Fort Collins • Longmont • Loveland

www.prpa.org

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-93:
Xcel 2025 Near Term Procurement Report

Colorado PUC E-Filings System

Public Service Company of Colorado

2025 NEAR-TERM PROCUREMENT REPORT

Proceeding No. 21A-0141E

December 5, 2025

NOTICE OF CONFIDENTIALITY:
PORTIONS OF THIS REPORT HAVE BEEN FILED UNDER SEAL

Highly Confidential Information:
Pages 5, 7-8, 19-22, 24-25, 31-32, 34-36, 45-47, 49-57
Highly Confidential Appendix A
Highly Confidential Attachment 2

Xcel Energy®

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1. EXECUTIVE SUMMARY

The objective of the Near-Term Procurement ("NTP") is "to procure tax-advantaged clean generation and firm generation, in light of the recent passage of H.R. 1 by Congress and recent directives from Governor Polis." The NTP resulted in a robust competitive response in an abbreviated period. The strong response to the NTP Request for Proposals ("RFP") creates a bid pool that allows for a portfolio that can advance the objectives approved by the Commission.

This NTP Report details the portfolio of resources for which Public Service Company of Colorado ("Public Service" or the "Company") seeks approval to move forward into contract negotiations and follow-on Certificate of Public Convenience and Necessity ("CPCN") filings, respectively. The proposed NTP portfolio of 14 projects is forecasted to capture nearly $5 billion in tax credit benefits on a net present value basis, consists of bids with low costs relative to generic pricing and market conditions, includes projects that are geographically diverse across Colorado, and includes resources within the Denver Metro Constraint that provide additional transmission-related benefits. The success of the NTP RFP and the resulting proposed portfolio are the result of an innovative and collaborative process that was advanced with widespread stakeholder support.

The NTP portfolio proposed for approval here consists of the projects that, based on the information we have today, have both low costs and a pathway to development and deliverability. The Company therefore seeks approval of the portfolio, while also raising the need for continued implementation flexibility from the Commission as this portfolio of resources moves from resources in a planning framework to infrastructure in the ground. For example, the Company may need to move to backup bids quickly, or even defer some needs entirely to the Just Transition Solicitation ("JTS") Base RFP, as negotiations and project implementation unfold following a decision approving the NTP portfolio.

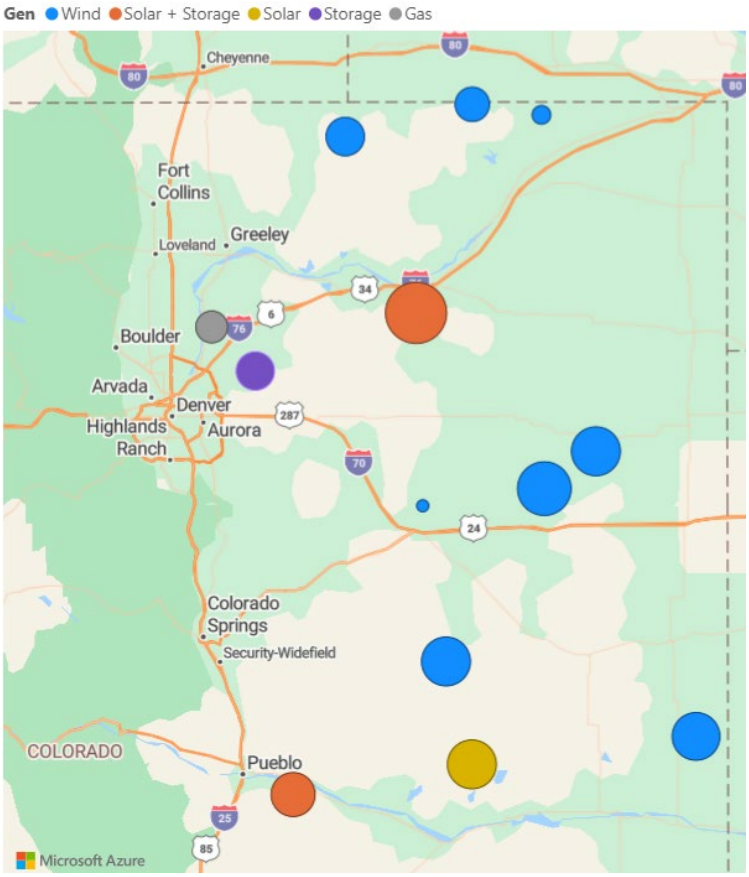
The proposed NTP portfolio of resources features 14 projects with ownership and technology diversity, respectively, as shown in Table 1 below.

Table 1: Proposed NTP Portfolio Statistics

NTP Selected Portfolio	Own	PPA	Total MW	Firm MW
Gas	200	0	**200**	196
Solar	0	500	**500**	80
Hybrid Solar	0	600	**600**	65
Hybrid Storage	0	600	**600**	305
Storage	300	0	**300**	181
Wind	1,583	1,119	**2,702**	371
Total	2,083	2,819	**4,902**	1,199
% of Total	42%	58%		

The 14 projects in the proposed NTP portfolio are dispersed across Colorado, bringing economic benefits to a variety of different areas of the State from project development, as reflected in Figure 1.

Figure 1: Proposed NTP Portfolio Project Locations



The projects consist of hybrid renewable/storage projects, standalone solar, standalone storage, wind, and thermal technologies. As set forth in the NTP Motion commencing this process, the portfolio was selected without the use of a capacity expansion model such

as EnCompass, but instead through a manual analysis that was appropriate given the timing needs.

The Company started the NTP process by working through bid packages in as detailed a manner as the time allowed. The Company then stacked the projects based on price (i.e., levelized energy cost ("LEC") or levelized capacity cost ("LCC")). While the proposed NTP portfolio consists of projects with low costs relative to the bid pool, Public Service did not simply select the lowest cost projects and package them together. Rather, the Company considered developer risk, system reliability needs informed by the Company's recent Effective Load Carrying Capability ("ELCC") and Planning Reserve Margin Study (also referred to as the "2024 Resource Adequacy Study"), deliverability, the need for incremental transmission based on preliminary assessments, the Commission's approved target acquisition levels, and the overall likelihood of specific projects coming to fruition.

The result is the proposed portfolio of Tier 1 projects in Table 2 below. Upon approval of the NTP, the Company intends to pursue negotiations and/or CPCNs for the Tier 1 projects.

Table 2: Proposed NTP Portfolio Projects (Tier 1)

Bid ID	Project Name	Commercial Structure	Gen	Nameplate (MW)	Nameplate (MW) II	First Summer Gen Year	LEC ($/MWh)	LCC ($/kW-mo)	County	Point of Interconnection
099	[redacted]	Own	Gas	200		2029	[redacted]	[redacted]	Weld	[redacted]
114		Own	Storage	300		2029			Adams	
046		PPA	Solar + Storage	400	400	2029			Morgan	
055		PPA	Solar + Storage	200	200	2029			Pueblo	
089		PPA	Solar	500		2029			Kiowa	
053		PPA	Wind	21		2027			Lincoln	
054		PPA	Wind	214		2028			Logan	
127		Own	Wind	608		2030			Kit Carson	
034		PPA	Wind	301		2028			Weld	
135		PPA	Wind	60		2028			Logan	
075		Own	Wind	500		2030			Yuma, Kit Carson	
057		PPA	Wind	23		2030			Logan	
068		PPA	Wind	500		2029			Lincoln	
097		Own	Wind	475		2030			Kiowa	

The pricing received across bids in response to the RFP overall is positive in looking at the proposed NTP portfolio more broadly and comparing it to the Company's expectations if it were to wait for the JTS Base RFP. Attachment JTL-10 in Proceeding No. 24A-0442E (the JTS proceeding) provided the following generic pricing without tax credits for wind and solar resources, excerpted in Table 3 below.

Table 3: JTS Updated Generic Pricing (without Tax Credits)

Levelized Costs by In-Service Year Without PTC (30 year life)		
Year	**Wind**	**Solar**
2028	$47.14	$62.14
2029	$48.32	$63.69
2030	$49.52	$65.28
2031	$50.76	$66.91
2032	$52.03	$68.59
2033	$53.33	$70.30
2034	$54.66	$72.06
2035	$56.03	$73.86
2036	$57.43	$75.71
2037	$58.87	$77.60
2038	$60.34	$79.54
2039	$61.85	$81.53
2040	$63.39	$83.57
2041	$64.98	$85.66
2042	$66.60	$87.80
2043	$68.27	$89.99
2044	$69.98	$92.24
2045	$71.72	$94.55
2046	$73.52	$96.91
2047	$75.36	$99.34
2048	$77.24	$101.82
2049	$79.17	$104.36
2050	$81.15	$106.97

Wind LECs in the proposed NTP portfolio of Tier 1 projects range from approximately $20/MWh to $43/MWh, beating these non-tax-advantaged generic pricing estimates for wind projects. Solar LECs are approximately $37/MWh, again comparing favorably to non-tax-advantaged solar generic estimates in the JTS.

The high likelihood of project implementation challenges from emerging financial, supply chain, or other issues also requires a robust set of backup bids, or Tier 2 projects. These projects are shown in Table 4 below and—like the Tier 1 projects—include renewable/storage hybrid, standalone solar, standalone storage, and wind technologies, creating a diverse pool of projects that the Company can turn to if challenges ensue with any Tier 1 projects. The Tier 2 projects create at least the potential for like-for-like replacement on a technology-specific basis to try and maintain the technology diversity of the approved NTP portfolio, as practicable.

Table 4: NTP Backup Bids Projects (Tier 2)

Bid ID	Project Name	Commercial Structure	Gen	Nameplate (MW)	Nameplate II (MW)	First Summer Gen Year	LEC ($/MWh)	LCC ($/kW-mo)	County	Point of Interconnection
118	[redacted]	PPA	Storage	400		2029	[redacted]	[redacted]	Routt	[redacted]
113		PPA	Storage	300		2029			Adams	
007		PPA	Storage	250		2030			Weld	
009		PPA	Storage	250		2030			Morgan	
022		PPA	Storage	400		2029			Crowley	
047		PPA	Solar + Storage	250	250	2029			Cheyenne	
049		PPA	Solar + Storage	200	200	2029			Pueblo	
144		Own	Solar + Storage	260	260	2029			Morgan	
094		Own	Solar + Storage	450	450	2030			Adams	
003		PPA	Solar	500		2029			Kiowa	
023		PPA	Solar	400		2030			Crowley	
051		PPA	Wind	150		2029			Lincoln	
154		PPA	Wind	203		2030			Kiowa, Prowers	
077		Own	Wind	500		2030			Kiowa, Prowers	

In assessing the proposed NTP portfolio in totality, there are several broader considerations at play with the Tier 1 projects (proposed NTP portfolio) and Tier 2 projects (backup bids).

First, two core principles of NTP portfolio development were minimizing developer risk and deliverability. Two Tier 1 projects, Bid 089 (500 MW power purchase agreement ("PPA") solar) and Bid 068 (500 MW PPA wind), have heightened developer and/or deliverability risk. For that reason, these two Tier 1 projects have designated proposed Tier 2 projects to take their place if and when critical challenges arise in implementation.

For Bid 089 (500 MW PPA solar), Bid 003 (also 500 MW PPA solar) is the designated backup bid. The former is lower cost but, in the Company's view, higher risk than the latter project given concerns about the project's interconnection plan coupled with past history with the project's developer in prior resource solicitations. It is therefore appropriate to have a designated Tier 2 project to take the place of Bid 089 if necessary. For Bid 068 (500 MW PPA wind), Bid 051 (150 MW PPA wind) is the designated backup bid. The Company identified higher deliverability risk with Bid 068, but that bid is lower cost than Bid 051. On the other hand, Bid 051 has less deliverability risk given its location on the Company's system and its point of interconnection ("POI"). While the designated Tier 2 project is smaller, the Company brings it forward as a designated backup bid given ongoing concerns with Bid 068.

Second, several projects (Bid 135 (60 MW PPA wind), Bid 057 (23 MW PPA wind), Bid 097 (475 MW owned wind), and Bid 053 (21 MW PPA wind)) represent either expansions of existing projects or repowered projects, respectively, which should lower the development risk. Repowering projects also have the potential to capture tax benefits for customers. In the case of Company-owned projects, these benefits flow directly to customers, whereas with PPAs, the developers receive the value of tax credits, and they pass on some amount of benefit to customers through lower energy rates. Regardless of ownership structure, however, these expansions reduce development risk and

deliverability challenges, leading to their selection in the proposed NTP portfolio as Tier 1 projects.

Bid 097 is an expansion of a project that previously encountered cultural resource impact challenges; however, previous efforts to resolve those issues allow for this development. Bid 053 (21 MW PPA wind) is the result of a project expansion and repowering to capture tax credits across the entirety of the project. The expansion of the existing project requires the Company's approval under an existing PPA, and while the expansion is the lowest cost project by a substantial margin ($[redacted]/MWh), it is unclear whether the developer is passing along benefits tied to the entire project, rather than just the expansion. The Company will continue to work with the developer upon portfolio approval to ensure customers are getting a sufficient level of benefit from the repower to justify the Company permitting the expansion that facilitates this bid overall.

Third, the Proposed NTP Portfolio does not currently have any independent power producer ("IPP") thermal bids as either Tier 1 or Tier 2 projects. This is unfortunate from the Company's perspective, but two dynamics led to this result. First, the lowest-priced IPP project is approximately $[redacted]/kW-month (Bid 134 (190 MW PPA thermal))—notably higher than Bid 099 (200 MW owned thermal), which is the lowest cost thermal project overall at a LCC just under $[redacted]/kW-month. Nonetheless, the Company seriously considered recommending approval of Bid 134 in addition to Bid 099 (200 MW owned thermal) in the interest of diversifying thermal ownership—but there is more to this bid than simply the LCC and ownership structure. Material model PPA redlines accompanied the bid, including provisions to both allow for a free walkaway in the event of project failure *and* provisions requiring the Company's customers to repay the bidder for all project-related expenditures incurred to the date of the walkaway/failure. Additionally, the bid does not have a full development picture with uncertainties around major equipment procurement and interconnection to the Public Service system. The Company cannot accept such terms or uncertainties, which create risk to customers by providing the developer with no incentive to complete the project (i.e., the free walkaway), exposure to pay for costs incurred, and exposure to future reliability uncertainty.

Moving to a second and related IPP thermal item, the pricing increased substantially for IPP thermal projects after Bid 134 (190 MW PPA thermal). Pricing landed in the mid-$30s/kW-month (i.e., $35/kW-month and above), leading the Company to not take action above the 200 MW of designated thermal provided for in the NTP Motion granted by the Commission to commence this NTP process.

The NTP portfolio proposed here fulfills overarching resource acquisition objectives of capturing tax-advantaged energy resources within the limited time window of H.R. 1 and advancing supporting dispatchable generation. This represents the best, and likely last,

opportunity to acquire tax-advantaged clean energy generation necessary to meet the State's emission reduction goals and manage future costs.

While this portfolio is an opportunity for Public Service customers and the State, challenges remain. To capture the benefits of soon-to-be expiring tax credits, the window for bidders to respond to the NTP RFP was intentionally short—and so was the Company's subsequent window to analyze and conduct due diligence on bids. This was necessary under the circumstances, but it is far from ideal. Developing resource portfolios without a computerized planning model is not risk-free and presents additive challenges; for example, there will be additional future costs associated with transmission and delivery. Future challenges with portfolio implementation may result from this expedited approach. Moreover, although the Company has a strong portfolio of opportunities that can capture tax benefits and add accredited capacity to Public Service's system, power development in general remains challenging. Supply chain issues persist, federal energy policy continues to shift, and the Public Service system continues to navigate resource adequacy stressors due to demand growth that is not being paced by new generation. Additionally, the bid pool for this NTP, in the absence of a conforming bid policy, is replete with heavy PPA redlines that in some instances materially alter the risk profile for customers and the allocation of risk between the Company (and its customers) and the IPP counterparty. Lastly, the limited window for bid evaluation means interconnection, transmission deliverability, and contracting challenges may still lie ahead for Tier 1 projects, reinforcing the need for a pool of approved Tier 2 projects.

The NTP seizes the limited opportunity for tax advantages that remains following the passage of H.R. 1. The Company is committed to working through issues and challenges that arise in portfolio implementation to bring the NTP portfolio to fruition upon approval by the Commission.

2. INTRODUCTION AND BACKGROUND

Public Service files this NTP Report in accordance with Commission Decision No. C25-0562-I issued on September 8, 2025 (the "NTP Initiation Decision"), which granted with modifications the Joint Motion to Initiate Near-Term Procurement filed on August 22, 2025, by Trial Staff of the Commission, the Office of the Utility Consumer Advocate, the Colorado Energy Office, and Public Service (the "NTP Motion").

The NTP Motion, as modified and approved by the NTP Initiation Decision, established the framework for an expedited resource solicitation process in advance of the Company's forthcoming JTS Phase II process in Proceeding No. 24A-0442E, with two primary objectives: (1) maximizing the capture of tax-advantaged clean energy projects in light of the federal tax credit changes enacted in July 2025 under H.R. 1, as well as subsequent policy directives from Governor Polis, and (2) securing cost-effective projects capable of supporting near-term reliability and resource adequacy needs. In addition to outlining parameters for the NTP solicitation and bid review process, the NTP Motion established specific resource acquisition targets of up to 4,000 MW (nameplate) for renewable energy and hybrid projects, up to 200 MW (accredited) of thermal generation, and up to 300 MW (accredited) of additional firm dispatchable generation.

Consistent with the timeline approved in Paragraph 33 of the NTP Initiation Decision, the Company issued the NTP RFP on August 29, 2025, with a deadline for bid submissions of October 6, 2025. Notices of intent to respond were due by September 24, 2025, following a bidder's conference held the week prior. The Company commenced bid review and due diligence on October 7, 2025, and ultimately identified a portfolio of 14 projects proposed for acquisition along with 14 proposed backup projects, as detailed in Sections 4 and 5 of this NTP Report. The Company also addresses specific reporting commitments established by the NTP Motion and NTP Initiation Decision in the relevant report sections.

The remainder of this report is structured as follows:

- **Section 3** provides an overview of the RFP and the bids received, including characteristics of the bid pool.
- **Section 4** discusses the Company's proposed NTP portfolio, including descriptions of the projects, cost-recovery considerations, potential deliverability risks, and other considerations.
- **Section 5** presents the set of projects the Company recommends as backups for the proposed NTP portfolio.

- **Section 6** describes the Company's bid evaluation and portfolio selection processes, including the strategies employed to evaluate the significant volume of bids under the compressed schedule of the NTP.
- **Section 7** discusses the projects that the Company is not advancing in either the proposed NTP portfolio or the backup pool, and the pricing and/or deliverability reasons why those projects were not selected.
- Finally, **Section 8** discusses the next steps in the NTP process.

3. OVERVIEW OF SOLICITATION RESPONSE AND BIDS RECEIVED

Public Service had a strong response to the NTP RFP. More specifically, at 41,900 megawatts ("MW")[1] the Company received an NTP bid pool equal to nearly ten times the target of 4,500 MW.

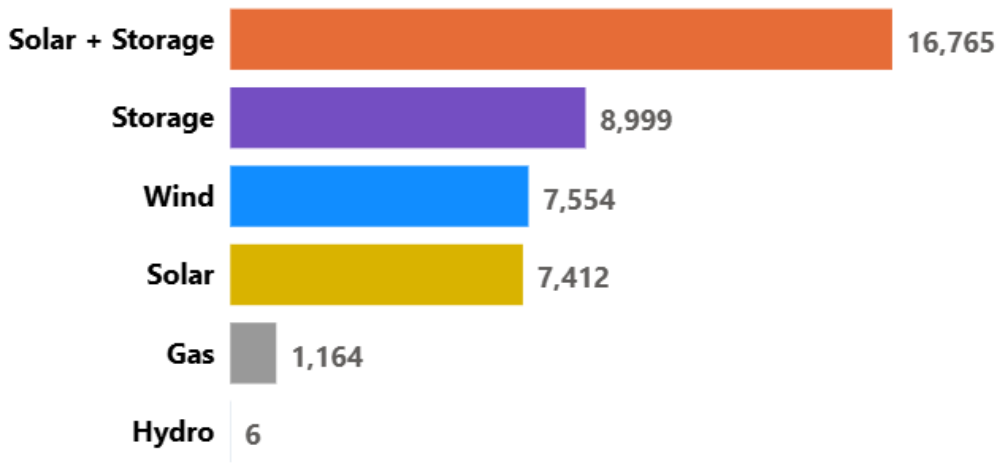
The NTP RFP response includes 161 bids across 128 unique projects from 49 bidder companies. There are more individual bids than unique projects due to the allowed variations bidders could propose for the same project, such as a Power Purchase Agreement ("PPA") bid and an ownership bid.

3.1 BID POOL CHARACTERISTICS

The NTP RFP bid pool is dispersed across several types of generation technologies.

Renewable and storage projects accounted for approximately 97% of the total MW in the NTP response, as shown in Figure 2 below. Standalone dispatchable resources, excluding hybrid storage, accounted for nearly a quarter of proposed NTP capacity.

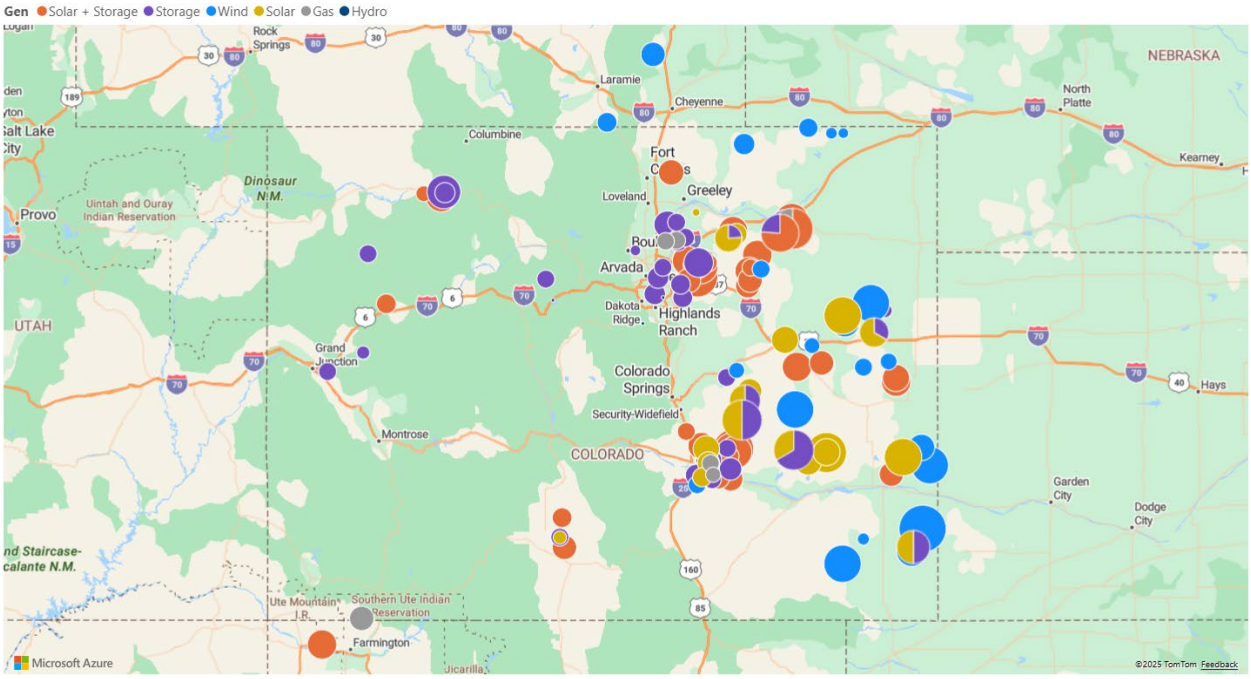
Figure 2: Maximum Unique NTP MW by Resource Type



NTP projects are located across the State, as shown in Figure 3 below.

[1] This value represents the sum of maximum unique NTP project MW.

Figure 3: Geographic Distribution of NTP Bids by Resource Type



Wind bids, marked by the blue bubbles in Figure 3 above, were proposed in the eastern half of the State with the largest projects in the central and southeastern areas. Solar bids, marked by the yellow bubbles above, were mostly concentrated in the Pueblo, central eastern, and southeastern areas of the State. Storage bids, marked by the purple bubbles above, have positive geographic diversity with projects located in the Denver Metro area, Routt County, on the Western Slope, and in the central eastern and southeastern areas of the State. Thermal bids, as marked by the gray bubbles above, are concentrated in the Denver Metro, Pueblo, Brush, and southwestern areas of the State.

The vast majority of NTP projects begin contributing to the system in either 2029 or 2030, with nameplate capacity shown in Figure 4 and accredited capacity shown in Figure 5 below based on the first summer season in which the project can contribute to Company capacity needs.

Figure 4: NTP Max Nameplate MW by First Summer

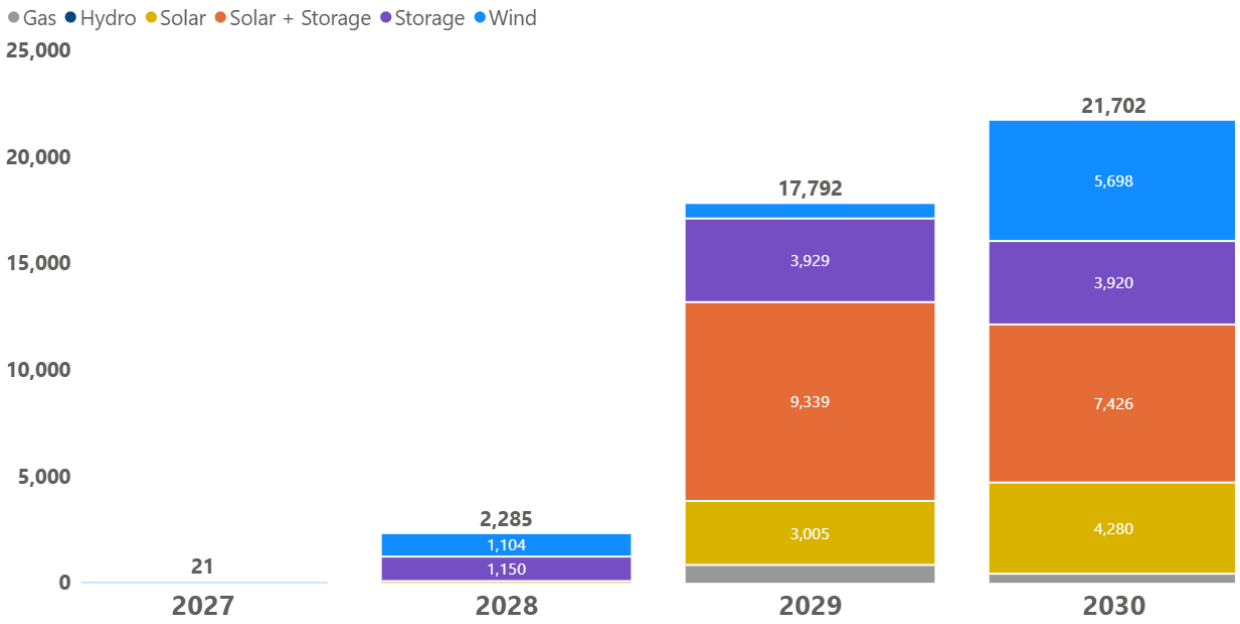
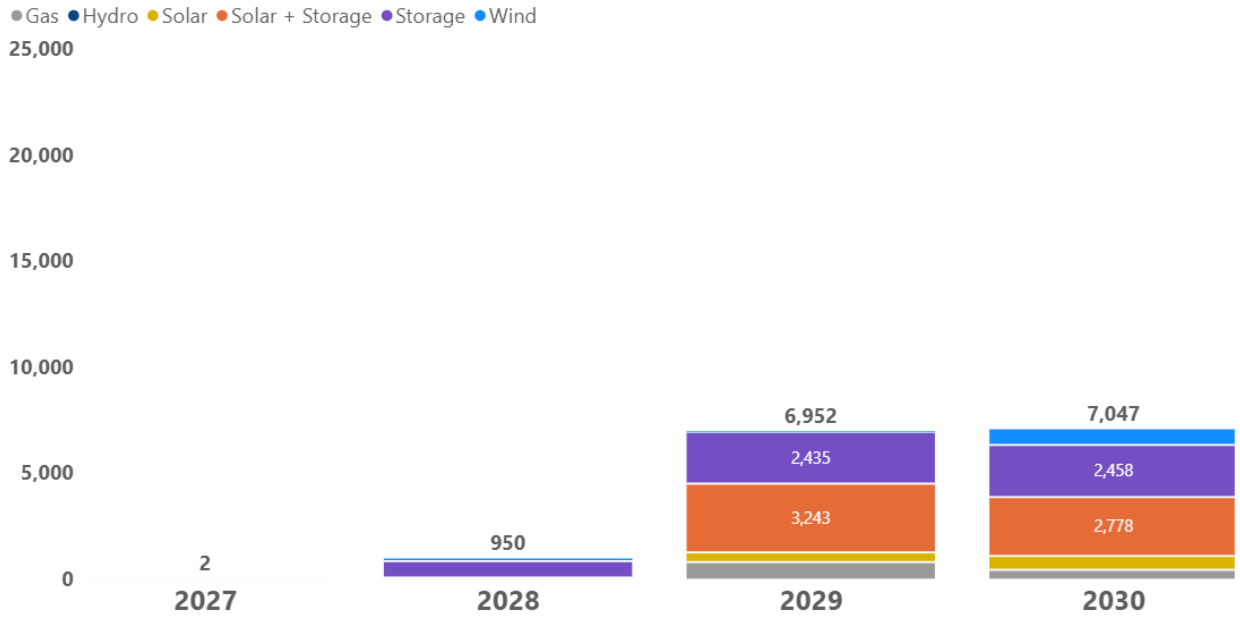
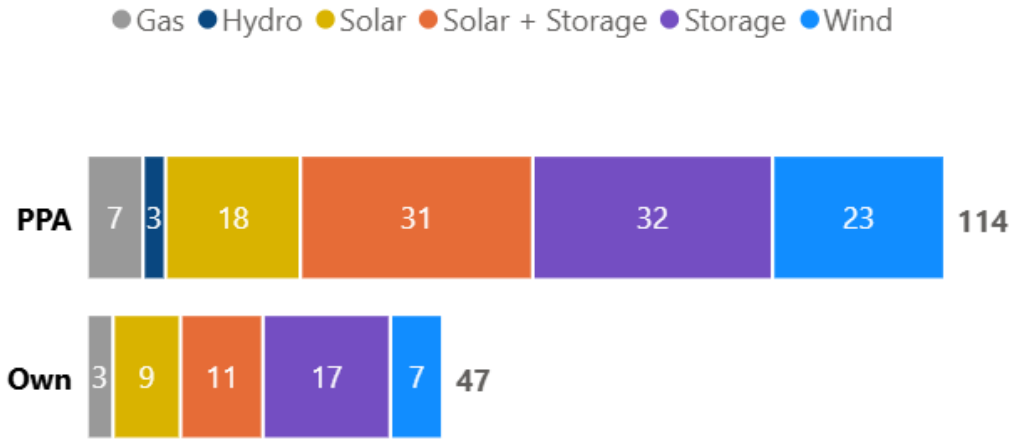


Figure 5: NTP Max Accredited MW by First Summer



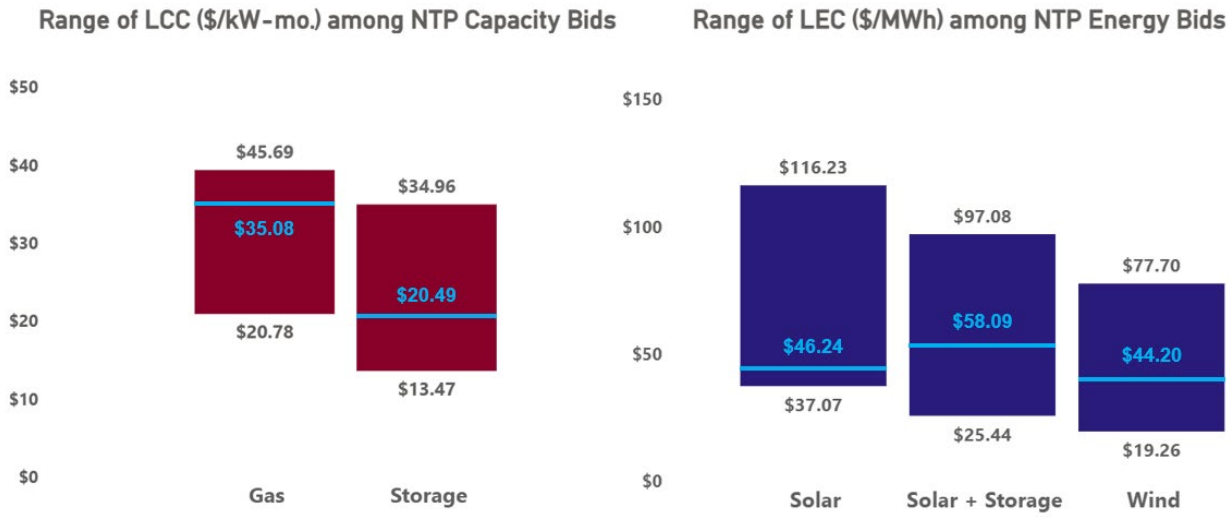
Approximately 70% of NTP bids proposed PPAs (as opposed to self-build or build-transfer), as detailed in Figure 6 below.

Figure 6: NTP Bids by Commercial Structure and Resource Type



The price range for energy resources bid into the NTP varied from $19.26/MWh on the lowest end to $116.23/MWh on the highest end, as shown in Figure 7 below. The price range for capacity resources varied from $13.47/kW-month (lowest) to $45.69/kW-month (highest). In Figure 7, median levelized costs by resource type are shown as a light blue line and value in each of the floating bars.

Figure 7: Range of NTP Bid Levelized Costs by Resource Type*



** Light blue lines represent median levelized costs. LEC for Hybrids is the modified scoring LEC.*

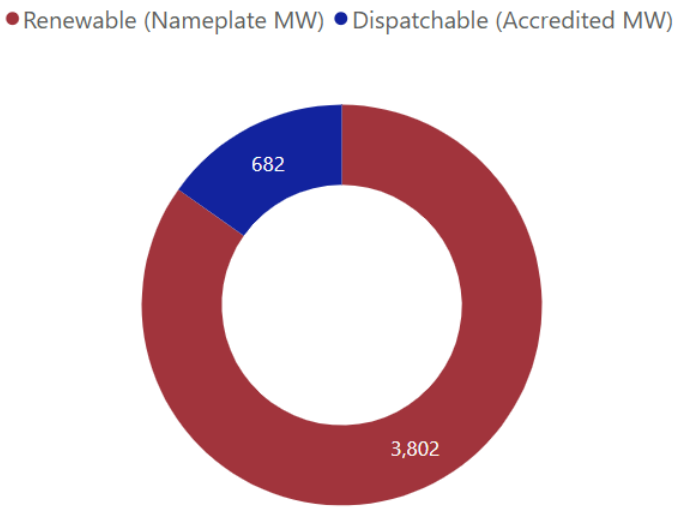
The Company provides detailed characteristics for each NTP bid in Highly Confidential Appendix A to this NTP Report.

4. PROPOSED NTP PORTFOLIO

The Company's proposed NTP portfolio consists of 14 projects from 9 bidder companies totaling approximately 4,900 MW of nameplate capacity.

The portfolio includes 3,802 MW of combined nameplate wind, solar, and hybrid solar capacity and 682 MW of combined accredited standalone storage, hybrid storage, and thermal capacity, as shown in Figure 8 below.

Figure 8: NTP Portfolio Nameplate Renewable MW, Accredited Dispatchable MW



The NTP portfolio achieves the resource-specific capacity acquisition targets detailed in the NTP Motion, as shown in Table 5 below, and which were informed by the renewable capacity added in the JTS Phase I Base portfolio with Low Load and $0 per ton of CO_2 as the cost of carbon assumption.[2]

Table 5: NTP Portfolio vs. NTP Target, JTS Phase I Low $0CO2

Resource Type	JTS Phase I (MW)	NTP Target (MW)	NTP Portfolio (MW)	% of NTP Target
Renewable	4,000	4,000	3,802	95%
Dispatchable*	1,372	500	682	136%
Total	**5,372**	**4,500**	**4,484**	**100%**

* The Dispatchable MW values in this table represent the combined accredited MW of standalone storage, hybrid storage, and gas CT resources.

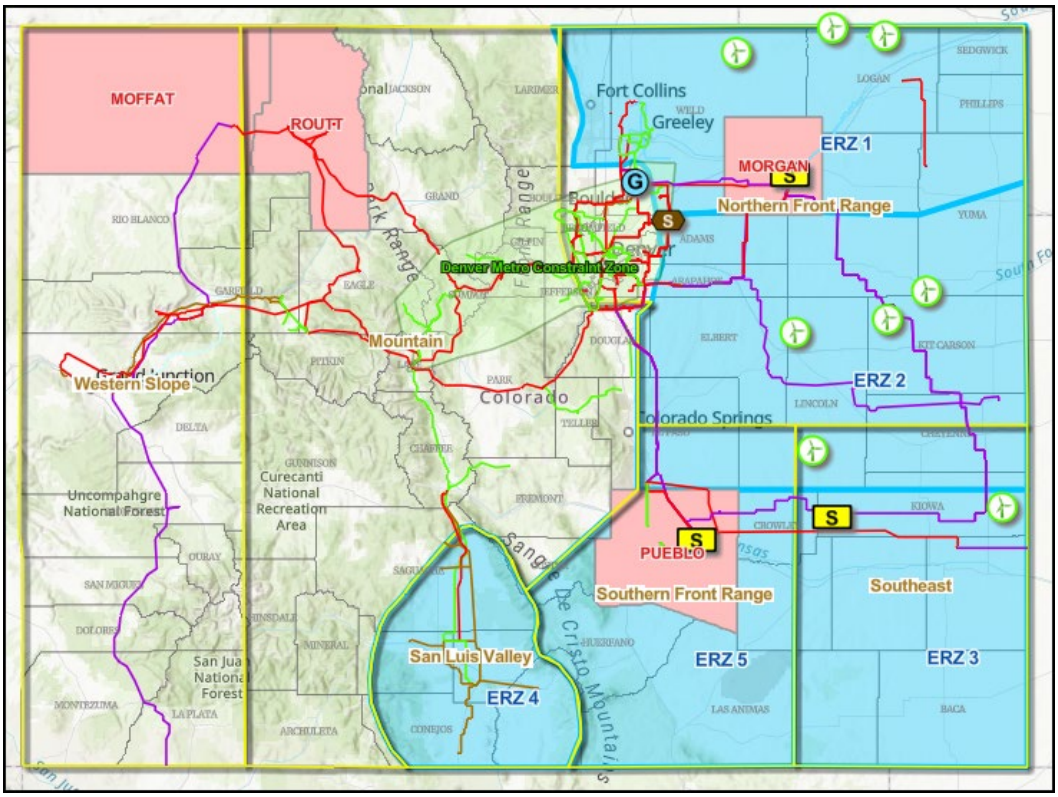
[2] The JTS Phase I Base Plan using the Low Load forecast and $0 per ton of CO2 as the cost of carbon assumption added 2,800 MW of wind resources, 1,200 MW of solar resources, and 1,400 MW of gas CT resources. The Company applied a 98% ELCC to the gas CT resources in the Phase 1 portfolio, per the 2024 Resource Adequacy Study (Hrg. Ex. 109, Attachment ZM-1, Rev. 1, in Proceeding No. 24A-0442E), to calculate the 1,372 MW of accredited dispatchable capacity shown in the table.

The NTP portfolio's energy resources are located east of the Front Range – with wind projects in the eastern plains from the northern border to the Arkansas River, standalone solar in the southeast, and solar plus storage northeast of the Denver Metro area. The portfolio's capacity resources, including thermal and standalone storage projects, are located within the Denver Metro area to provide valuable benefits to the transmission system.

Figure 9 below shows each project's location with respect to the following:

- Pueblo, Routt, Morgan, and Moffatt Counties (red layer)
- The area of the system that supports operations by avoiding the Denver Metro Constraint[3] (green layer)
- Energy Resource Zones (blue layers, blue text)
- Solar Resource Zones (bold yellow boundaries, yellow text)
- Major Transmission Lines (purple, red, green, blue, and brown lines)

Figure 9: NTP Selected Portfolio Detailed Map



[3] *See* Proceeding No. 24A-0442E, Hrg. Ex. 118, Attachment JTL-9 (DM Constraint Map Descriptions).

Most of the proposed NTP portfolio projects achieve commercial operation by the summer of 2029, as shown in Figures 10 and 11 below.

Figure 10: NTP Portfolio Nameplate MW Online by Summer Reliability Season

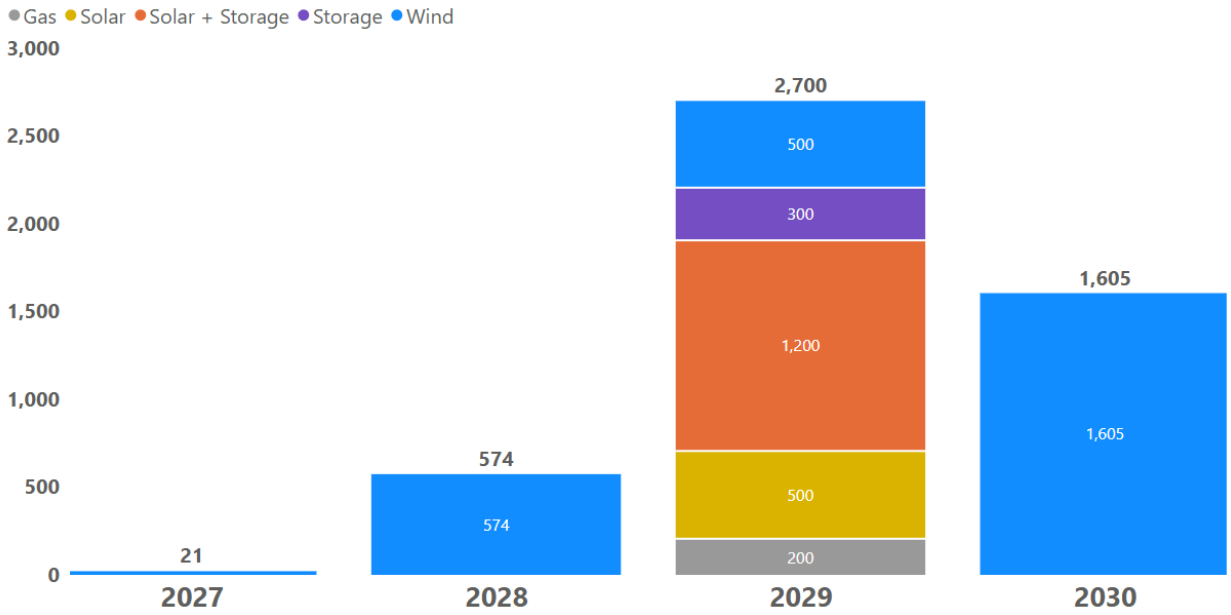
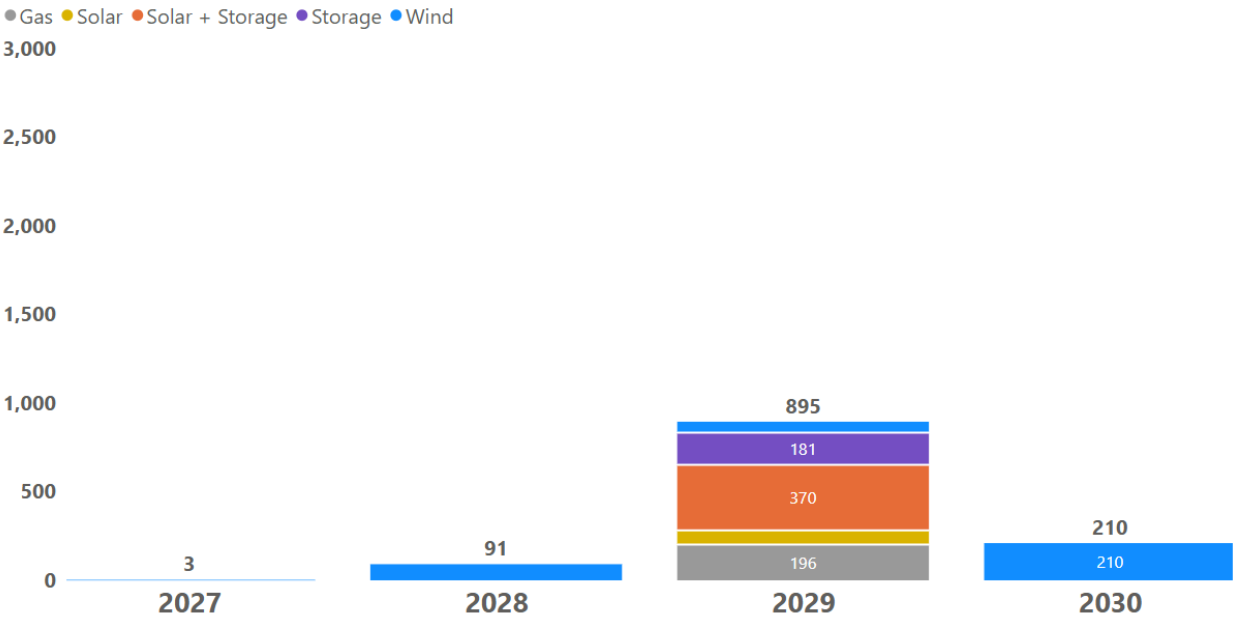


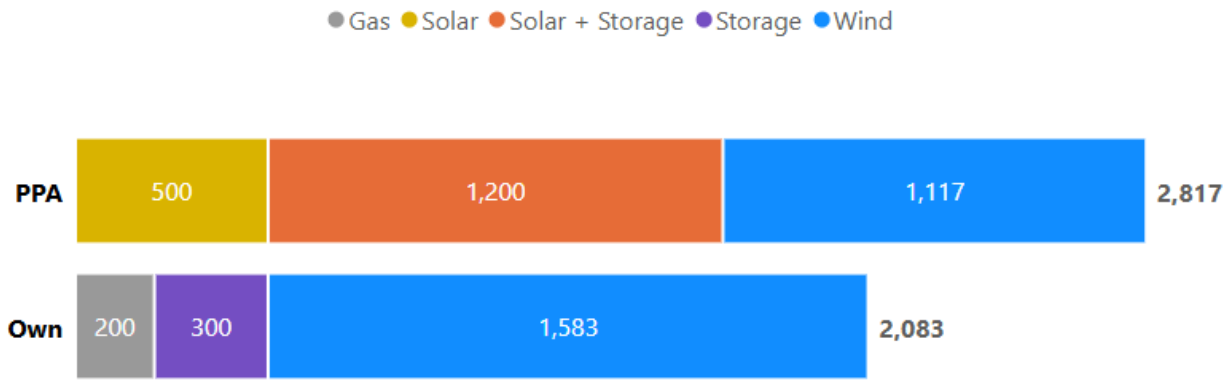
Figure 11: NTP Portfolio Accredited MW Online by Summer Reliability Season



The proposed NTP portfolio has a mix of power purchase agreements (PPAs) and Company-owned projects (self-build and build-transfer) with approximately 58%

purchased and 42% Company-owned on a nameplate MW basis (as shown in Figure 12 below). This balance is slightly skewed from expectations arising from the 2021 Electric Resource Plan and Clean Energy Plan ("2021 ERP & CEP") and the NTP Motion, but reflects the characteristics of the bids received in the NTP and can be reviewed during the JTS Phase II analysis on a combined basis.

Figure 12: Nameplate MW Ownership Balance of NTP Portfolio by Resource Type



4.1 OVERVIEW OF NTP PORTFOLIO PROJECTS

Across its 14 projects, the NTP portfolio achieves the NTP's resource-specific acquisition targets while balancing competitive pricing, acceptable development risk, interconnection feasibility, system-level impacts, and priority locations–including projects within Just Transition Communities and those that avoid the Denver Metro Constraint.

Table 6 below summarizes the 14 projects in the proposed portfolio.

Table 6: NTP Portfolio Projects

Bid ID	Project Name	Commercial Structure	Gen	Nameplate (MW)	Nameplate (MW) II	First Summer Gen Year	LEC ($/MWh)	LCC ($/kW-mo)	County	Point of Interconnection
099	[redacted]	Own	Gas	200		2029	[redacted]	[redacted]	Weld	[redacted]
114		Own	Storage	300		2029			Adams	
046		PPA	Solar + Storage	400	400	2029			Morgan	
055		PPA	Solar + Storage	200	200	2029			Pueblo	
089		PPA	Solar	500		2029			Kiowa	
053		PPA	Wind	21		2027			Lincoln	
054		PPA	Wind	214		2028			Logan	
127		Own	Wind	608		2030			Kit Carson	
034		PPA	Wind	301		2028			Weld	
135		PPA	Wind	60		2028			Logan	
075		Own	Wind	500		2030			Yuma, Kit Carson	
057		PPA	Wind	23		2030			Logan	
068		PPA	Wind	500		2029			Lincoln	
097		Own	Wind	475		2030			Kiowa	

Below, the Company provides more detailed reviews of the 14 projects in the NTP portfolio. Please see Appendix A for additional insights and data about the selected projects and all other bids received in response to the NTP RFP.

Wind Projects: Repowers and PPA Extensions of Existing Projects

Bid ID	Project Name	Commercial Structure	Gen	Nameplate (MW)	First Summer Gen Year	LEC ($/MWh)	County	Point of Interconnection
053	[redacted]	PPA	Wind	21	2027	[redacted]	Lincoln	[redacted]
054		PPA	Wind	214	2028		Logan	
034		PPA	Wind	301	2028		Weld	
135		PPA	Wind	60	2028		Logan	
057		PPA	Wind	23	2030		Logan	

Five of the nine wind projects in the NTP portfolio, totaling 619 MW of the 2,702 MW of wind projects in the portfolio, are either repowers or PPA extensions of existing wind farms from which the Company currently purchases power. All of these projects' all-in levelized costs[4] fall below the NTP wind project median all-in levelized cost of $42.75/MWh.

In addition to the favorable pricing, the Company selected the PPA extensions – Bids 135 and 057 – to move now at the opportunity to renew them. The Company selected the repowers – Bids 053, 054, and 034 – due to their low development risks as existing projects. All of these projects are from experienced project developers with extensive project development track records and with which the Company has long-term operating relationships.

Four of these projects – Bids 053, 054, 034, and 135 – comprise the only projects in the NTP portfolio that contribute capacity and energy by the beginning of the summer 2028 reliability season.

Wind Projects: New Projects

Bid ID	Project Name	Commercial Structure	Gen	Nameplate (MW)	First Summer Gen Year	LEC ($/MWh)	County	Point of Interconnection
127	[redacted]	Own	Wind	608	2030	[redacted]	Kit Carson	[redacted]
075		Own	Wind	500	2030		Yuma, Kit Carson	
068		PPA	Wind	500	2029		Lincoln	
097		Own	Wind	475	2030		Kiowa	

The four new wind projects in the NTP portfolio – Bids 127, 075, 068, and 097 – total to 2,083 MW of the 2,702 MW of wind projects in the portfolio. Each project's all-in levelized cost is either below or within [redacted] of the NTP wind project median all-in levelized cost of $42.75/MWh.

[4] All-in levelized cost simply means the estimated costs of transmission facilities and upgrades are included in the costs. For example, any project proposing a line tap for their interconnection was evaluated on a standalone basis and the added cost of a new switching station was included in the all-in levelized cost.

Beyond their competitive prices, the Company selected these projects over other NTP projects due to their viable interconnection plans, surmountable development challenges, and backing by reputable project developers.

Bid 068 proposes to come online the earliest, contributing its capacity and energy to the summer 2029 reliability season.[5] Bids 127, 075, and 097 begin operations before the summer 2030 reliability season (with commercial operation dates ("CODs") in the latter half of 2029).

Solar Project

Bid ID	Project Name	Commercial Structure	Gen	Nameplate (MW)	First Summer Gen Year	LEC ($/MWh)	County	Point of Interconnection
089	[redacted]	PPA	Solar	500	2029	[redacted]	Kiowa	[redacted]

At 500 MW nameplate, Bid 089 is the only standalone solar project in the NTP portfolio. Its all-in levelized cost is approximately [redacted] lower than the NTP solar project median all-in levelized cost of $42.69/MWh. Beyond its competitive price, the Company selected this project due to its solar resource diversity. This project proposes beginning operations before the summer 2029 reliability season. The only significant risk to the project is discussed in Sections 4.6 and 5, where the Company discusses a proposed alternate interconnection plan that would impact the project's COD (similar to Bid 068).

Solar + Storage Projects

Bid ID	Project Name	Commercial Structure	Gen	Nameplate (MW)	Nameplate (MW) II	First Summer Gen Year	LEC ($/MWh)	County	Point of Interconnection
046	[redacted]	PPA	Solar + Storage	400	400	2029	[redacted]	Morgan	[redacted]
055		PPA	Solar + Storage	200	200	2029		Pueblo	

The two solar plus storage projects in the NTP portfolio – Bids 046 and 144 – total to 660 MW nameplate of solar capacity and 660 MW nameplate of 4-hour storage capacity. Each project's all-in levelized cost is well below the NTP solar plus storage project median all-in levelized cost[6] of $57.23/MWh.

Beyond their competitive prices, the Company selected these projects over other NTP projects due to their viable interconnection plans and lack of significant development challenges identified through due diligence to date. Further, these projects' location northeast of the Denver Metro in the Northern Front Range Solar Resource Zone broadens the geographic diversity of the Company's solar resource portfolio.

[5] Given the interconnection risk described in Section 4.6, it will likely commence operations before the summer 2030 reliability season.
[6] Section 6.2 addresses the LEC approach used to evaluate and compare hybrid solar plus storage projects. The value shown here is the scoring Hybrid LEC.

Both projects begin operations before the summer 2029 reliability season.

Standalone Storage Project

Bid ID	Project Name	Commercial Structure	Gen	Nameplate (MW)	Nameplate (MW) II	First Summer Gen Year	LCC ($/kW-mo)	County	Point of Interconnection
114	[redacted]	Own	Storage	300		2029	[redacted]	Adams	[redacted]

At 300 MW nameplate, Bid 114 is the only standalone storage project in the NTP portfolio. The project's all-in levelized cost is lower than the NTP standalone storage project median all-in levelized cost of $18.12/kW-month. A key reason the Company selected this project over other comparable standalone storage projects is its location on the unconstrained side of the Denver Metro Constraint, which will support system operations. This project begins operations before the summer 2029 reliability season.

Bid 114 also has a corresponding PPA alternative, Bid 113, which is identical in all respects except LCC. Bid 113 is somewhat lower in LCC ranking, at [redacted]/kW- mo, but as a standalone storage project would have negative impacts to the Company's balance sheet. The specific impacts of this project, if fully mitigated, could add an incremental system revenue requirement that equates to a LCC adder of almost $7/kW-mo[7] applied to the PPA version of the project, making it significantly more expensive than the build-own transfer ("BOT") version. As the developer would benefit from the project being selected as either PPA or BOT, albeit in perhaps differing amounts, as well as the previously mentioned debt implications and to more equitably balance the ownership percentages in the portfolio, the Company is recommending Bid 114 over Bid 113. Bid 113 is included in the list of backup storage projects.

Thermal Project

Bid ID	Project Name	Commercial Structure	Gen	Nameplate (MW)	Nameplate (MW) II	First Summer Gen Year	LCC ($/kW-mo)	County	Point of Interconnection
099	[redacted]	Own	Gas	200		2029	[redacted]	Weld	[redacted]

At 200 MW nameplate, Bid 099 is the only thermal project in the NTP portfolio. Not only was this bid the most competitively-priced thermal project in the NTP, but its all-in levelized cost is a dramatic [redacted] lower than the NTP thermal project median all-in levelized cost of $34.68/kW-month. Like Bid 114, the NTP portfolio's standalone storage bid, Bid 099 will also support system operations due to its location on the unconstrained

[7] Initial calculations indicate Bid 113 results in approximately $[redacted] million of imputed debt, which would be equivalently offset by a 50 bps increase in equity percentage, which translates to an incremental $[redacted] million per year revenue requirement. NPV of $[redacted] million per year for the 18 year term of the PPA factored into the LCC calculation equals a $[redacted]/kW-mo adder to the PPA LCC.

side of the Denver Metro Constraint. This project begins operations before the summer 2029 reliability season.

4.2 PORTFOLIO COSTS AND COST RECOVERY

This section discusses the costs of the proposed NTP portfolio and the Company's proposed cost recovery approach, as directed in the NTP Initiation Decision.[8] Although only the costs are addressed, it is important to understand that costs do not directly translate to customer rate increases. The proposed projects will also provide system benefits that can only be determined using computer modeling, and without factoring in the benefits, full customer rate impacts cannot be determined. It could be that the customer savings partially or even fully offset the costs, resulting in low rate impacts or even overall savings to customers; on the NTP timeline, however, the Company is not able to conduct such analyses within the expedited NTP procedural schedule.

NTP Portfolio Project Costs

The vast majority of NTP projects have corresponding tax credit savings that may no longer be available if those projects are procured post-NTP, e.g., in the JTS Base RFP or JTS Supplemental RFP processes. In general, this NTP can be considered an advancement of resources that otherwise would likely have been selected in the JTS, and also the completion of resources needed to comply with Colorado's energy policy goal to reduce carbon emissions by 80% from 2005 levels by 2030.[9] Per Commission directives in Proceeding No. 21A-0141E, the latter part of the 2021 ERP & CEP RAP (years 2029 and 2030) for resources needed to complete the Company's CEP was deferred to the future JTS for acquisition.[10] This NTP is now fulfilling a significant part of that role, advancing the 2021 ERP & CEP and adding the resources needed to reach the 2030 emissions reduction goal under Senate Bill 19-236.

Table 7 below summarizes the costs and tax benefits of the proposed portfolio. As reflected in the table, the estimated tax credits from NTP projects save customers approximately $4.97 billion on a net present value ("NPV") basis compared to the total portfolio NPV of approximately $7.75 billion. This represents a 39% savings to customers by procuring these resources now and not risking losing the tax credits.[11]

[8] *See* Decision No. C25-0652-I, at ¶ 24, Proceeding No. 21A-0141E.
[9] § 40-2-125.5(3)(a), C.R.S.
[10] *See* Decision No. C22-0459, at ¶¶ 4, 49, 161, 165, Proceeding No. 21A-0141E.
[11] 4,949 / (7,746+4,969) = 39%.

Please note that Bids 034 and 135 do not have tax credits as these projects are extensions/recontracts of existing facilities currently under contract to Public Service. However, procuring these bids now instead of in the JTS provides certainty to the owners and ensures they remain available to customers in the future—and are not sold to another off-taker.

Table 7: NTP Bid Costs and Tax Credits

Bid ID	Project Name	Commercial Structure	Gen	Bid Capex ($M)*	Tax Credits ($M)**	NPV Bid Costs ($M)***	NPV Tax Credits ($M)
127	[redacted]	Own	Wind	[redacted]	[redacted]	[redacted]	[redacted]
075		Own	Wind				
097		Own	Wind				
034		PPA	Wind				
053		PPA	Wind				
054		PPA	Wind				
057		PPA	Wind				
068		PPA	Wind				
135		PPA	Wind				
114		Own	Storage				
055		PPA	Solar + Storage				
046		PPA	Solar + Storage				
089		PPA	Solar				
099		Own	Gas				
TOTAL				$ 10,387	$ 6,665	$ 7,836	$ 4,809

* *Capex is estimated for PPA's based on average $/kW costs of the owned bids received.*
** *Tax credits are the notional value of estimated PTC and ITC credits, are grossed up for tax impacts, and do not consider curtailments.*
*** *NPV of costs are inclusive of embedded tax benefits.*

NTP Portfolio Cost Recovery

Upon approval of the proposed NTP portfolio, inclusive of any modifications from the Commission, the Company proposes the following treatment from a cost recovery perspective:

- First, the Rule 3617(d) presumption of prudence would attach to all implementation actions taken that are consistent with the approved portfolio, including actions consistent with an approved backup bid (Tier 2) process.[12]
- Second, for PPA and owned renewable projects, cost recovery would commence upon each project's COD through the Electric Commodity Adjustment until rolled

[12] *See* Rule 3617(d); *see also* NTP Initiation Decision, Decision No. C25-0652-I, at ¶ 27 ("Regarding the NTP Motion's proposals regarding Rule 3617(d), the Commission generally agrees that selected NTP projects will likely qualify for a presumption of prudence under Rule 3617(d). Consistent with past practices, however the Commission retains discretion to limit or condition the application of Rule 3617(d) until after we can evaluate the specific NTP project").

into base rates at a future time, consistent with traditional treatment for these types of projects.[13]

- Third, for PPA and owned dispatchable projects, cost recovery would commence upon each project's COD through the Purchased Capacity Cost Adjustment.[14]

- Finally, and relatedly, owned projects would be subject to the Cost-to-Construct ("CtC") Performance Incentive Mechanism ("PIM"), Operational PIM, and/or Availability PIM based on technology type for the owned project and consistent with the structure approved in Proceeding No. 24A-0417E.[15]

In addition, there are forward-looking cost recovery considerations as the Company moves through future rate proceedings. Bid 113 (300 MW PPA storage), if included in the NTP portfolio, (the Company has proposed an owned alternative through a BOT structure) creates additional imputed debt for the Company of over $[redacted] million. If taken along with Bid 134 (190 MW IPP thermal), which the Company does not recommend moving forward with at this time given contracting issues and other concerns, it would create an estimated $[redacted] million of total additional imputed debt for Public Service by 2029. The Commission has previously recognized that "[t]he financial lease and imputed debt issue, as articulated by Public Service, is a real concern that needs to be considered in this process" and that "concerns regarding finance leases are legitimate and should not be ignored."[16] Finance lease treatment for these two projects and a resulting $[redacted] million of additional imputed debt substantially reduces the Company's credit metrics.

The Commission has also acknowledged that it "has other tools at [its] disposal to wholistically address the Company's financial health";[17] these tools include an increased return on equity ("ROE"), an increased equity ratio, or earnings streams on PPAs, and Colorado has allowed for an increased equity ratio to mitigate the negative financial

[13] *See, e.g.,* Decision No. C24-0052, at ¶ 191, Proceeding No. 21A-0141E ("In connection with the establishment of the operational PIM, all projects subject to the operational PIM in this Proceeding will receive cost recovery through the appropriate rider (RESA or ECA) from the ISD of the project until the project is rolled into base rates.").
[14] *See, e.g.,* Decision No. C25-0435, at ¶ ¶ 50, 53, Proceeding No. 24A-0417E (providing in part: "Under the Settlement Agreement, Public Service may recover the costs of all capacity resources procured through the 2021 ERP/CEP in the PCCA with recovery commencing on any unit's commercial operation date …. We approve the Settlement Agreement's provisions regarding accelerated cost recovery without modification"); *see generally* Decision No. R20-0108, Proceeding No. 19A-0409E (approving the same recovery for the Manchief generator); Decision No. C10-1196, Proceeding No. 10A-372E (approving the same recovery for the Rocky Mountain Energy Center and Blue Spruce Energy Center generators).
[15] *See generally* Decision No. C25-0435, Proceeding No. 24A-0417E
[16] Decision No. C22-0459, at ¶¶ 340, 346, Proceeding No. 21A-0141E.
[17] Decision No. C22-0459, at ¶ 346, Proceeding No. 21A-0141E.

effects of imputed debt.[18] From the Company's perspective, regulated equity ratio is the most efficient lever to mitigate this impact, and NTP projects could be offset with additional basis points of equity ratio, all else being equal. The Company does not seek relief here to mitigate this impact, but raises it for Commission and party consideration as the proposed NTP portfolio is finalized and future cost recovery-related proceedings progress before the Commission.

4.3 TRANSMISSION INTERCONNECTION AND OPERATIONS CONSIDERATIONS

The Resource Planning team worked closely with Commercial Operations and multiple groups within the Company's Transmission Organization, including Planning, Engineering, Capital Projects Development, and Operations to evaluate interconnection, deliverability, and operational considerations with respect to the NTP RFP bid pool. The intention was, within the time allotted for evaluation, to evaluate interconnection feasibility, minimize incremental costs, maximize construction efficiency, and ensure reliability.

The focus of this collaboration was to curate a portfolio capable of delivering its capacity and energy to the Company's primary load center in the Denver Metro region while minimizing, as much as possible, known challenges such as the Denver Metro Constraint and new construction timelines.

Focus areas for this collaboration were as follows:

- Prioritizing new capacity within the Denver Metro region on the *unconstrained* side of the Denver Metro Constraint;
- Scrutinizing the feasibility of projects achieving their proposed CODs considering the complexity and required infrastructure of their proposed interconnection plans; and
- Evaluating the geographic diversity contributions of new renewable resources and their downstream impacts on system operations.

The proposed NTP portfolio reflects a balance of these considerations and results in:

[18] Decision No. C05-0049, at ¶ 95, Consolidated Proceeding No. 04A-214E (providing in part: "As part of the Settlement, the Parties recognize the Company's need to increase its equity ratio, as calculated for financial reporting purposes, to 56 percent in order to offset the debt equivalent value of existing purchased power agreements and to improve the Company's overall financial strength"); *see also Introduction to Debt Equivalency*, at 10-11 (Hrg. Ex. 145 in Phase I evidentiary hearings in this proceeding); *Concept Paper 2: Assessment of the Nevada Electric Utility Regulatory Framework*, at 58-59 (Hrg. Ex. 146 in Phase I evidentiary hearings in this proceeding, addressing Nevada statutory and regulatory structure for imputed debt identification and mitigation).

- The addition of 500 MW of dispatchable generation in the Denver Metro region on the unconstrained side of the Denver Metro Constraint (Bid 114 and Bid 099);
- The proposed alternate routing of four line taps to two shared switchyards to reduce costs and operational risks (for Bids 089, 068, 127 and 075, respectively); and
- The addition of 400 MW of solar resources in the Northern Front Range zone to balance the Company's 1,300 MW of existing solar resources concentrated in Pueblo and the San Luis Valley.

As part of the due diligence process described in Section 6.3, the Company's transmission planning team performed a Direct Current ("DC") Transfer Limit Study to provide an approximate evaluation of interconnection capacity available to individual bids. A major outcome of this type of analysis was identifying if there was insufficient interconnection capacity and/or if significant upgrades would be needed to accommodate the interconnection of the bid in question. However, pursuant to the Company's NTP Motion and the Commission decision approving it (Decision No. C25-0652-I), the Company's Transmission Planning team worked to determine a forecasted representative cost of transmission upgrades needed to interconnect and deliver the selected resources, based upon historic and relevant analyses.

The NTP's 4,092 MW of wind, solar, storage, and thermal resources follow on the heels of the 2021 ERP & CEP's addition of more than 6,000 MW of wind, solar, storage, and thermal generation to the system by the end of 2028.

As the next wave of generation projects following the 2021 ERP & CEP, the NTP projects will require companion transmission network upgrade projects to maintain system reliability and stability, as well as ensure the maximum deliverability of the new NTP resources into the Denver Metro load center. While the Company's proposed Denver Metro Transmission Network Improvement Project (Proceeding No. 24A-0560E) will address network upgrade requirements for the 2021 ERP & CEP resources, the Company has detailed the need for additional network upgrades alongside the next wave of generation projects after the 2021 ERP & CEP. Supporting analyses and discussion have been provided in this proceeding through the CEP Delivery Plan, in the Denver Metro Project CPCN proceeding, and in the JTS proceeding via the JTS Phase I Transmission Study.[19]

As discussed in these other proceedings and supporting studies, as the Company's generation system continues to evolve and transform, the transmission system needs to evolve and transform with it to reflect the fundamental changes to the system that have

[19] *See* Proceeding Nos. 21A-0141E, 24A-0560E, and 24A-0442E, respectively. The JTS Phase I Transmission Study was originally provided in Proceeding No. 24A-0442E but is being re-filed here as Attachment 1 to this report.

occurred through the clean energy transition – generation resources located close to the Company's load center are being retired and replaced primarily with renewable generation located in remote parts of the state. Transformation of the Company's transmission system will include a variety of traditional and advanced technologies that will upgrade existing transmission pathways, create new pathways to ease congestion on existing lines, expand and construct new substations, and construct grid support devices necessary to ensure the stability and reliability of the electric system.

Identification of the specific projects needed to facilitate delivery, reliability, and stability requires the specific details of the next wave of generation projects. However, for the evaluation and consideration of indicative costs, generic modeling can offer useful insights. Most recently, in the JTS Phase I Transmission Study, the Company identified approximately $2-2.5 billion in incremental, network transmission needed to support the deliverability of a portfolio with generation acquisitions in the range of the proposed NTP portfolio acquisition.[20] The study (provided as Highly Confidential Attachment 2 to this report) shows that the transmission planning team observed similar overloads in the Denver Metro Area consistent with the JTS Phase I Transmission Study.

As the Company moves ahead with the approved NTP portfolio and the ongoing JTS Two-Step Transmission analysis, additional refinement will occur, including the evaluation of alternatives to the current modeling and consideration of strategies to maximize the use of the Company's existing transmission system through the deployment of Advanced Transmission Technologies. This analysis is expected to take an additional 12-18 months as the Company engages internal stakeholders in planning, design, engineering, and cost estimation and advances the coordinated stakeholder processes, such as those ongoing at the Colorado Coordinated Planning Group, to identify opportunities for collaboration and mutually beneficial development.

4.4 RESOURCE ADEQUACY AND SYSTEM BENEFITS

The proposed NTP portfolio will add approximately 1,200 MW of accredited capacity to the Public Service system by the summer of 2030, improving—but not resolving—the Company's resource adequacy position in 2029 and 2030, as shown in Table 8 below.

The Company will continue to develop and bring forward solutions to address resource adequacy and system reliability needs through other appropriate proceedings, including the JTS Base RFP and JTS Supplemental RFP processes. The L&R table presentation in Table 8 builds from the L&R table presented in the JTS Rebuttal Testimony of Company

[20] *See*, the Direct, Supplemental Direct, and Rebuttal testimonies of Company witnesses Mr. Andrew W. Siebenaler and Mr. Steven Martz in Proceeding No. 24A-0442E.

witness Mr. Landrum,[21] and adds the expected accredited capacity of the NTP resources by year. It is expected that the load forecast will evolve, both due to decisions in the open JTS proceeding as well as updates to economic and large load forecasts, and this table will be updated and filed prior to the JTS Base RFP solicitation.

Table 8: Updated PSCo Summer Loads and Resources Balance with NTP Additions

Starting Capacity Position	2027	2028	2029	2030	2031
TOTAL ACCREDITED CAPACITY (12/25 Resources Outlook*)	7,243	7,922	7,658	7,651	7,344
CAPACITY NEED (JTS Rebuttal Load Forecast)	7,999	8,191	8,676	9,071	9,377
CAPACITY POSITION: LONG/(SHORT)	**(756)**	**(269)**	**(1,018)**	**(1,420)**	**(2,033)**

Updated Capacity Position with NTP Portfolio Additions	2027	2028	2029	2030	2031
TOTAL ACCREDITED CAPACITY	7,243	7,922	7,658	7,651	7,344
NTP Portfolio Additions	*3*	*94*	*989*	*1,199*	*1,199*
CAPACITY NEED	7,999	8,191	8,676	9,071	9,377
CAPACITY POSITION: LONG/(SHORT)	**(752)**	**(175)**	**(29)**	**(221)**	**(834)**

**Resource changes from JTS Rebuttal L&R reflect summer and winter 2026 Market Purchases; the inclusion of Pawnee Solar + Storage; updated CODs for 2021 ERP & CEP resources; updated Form Energy COD; updated Spring Canyon PPA expiration per PPA amendment; updated CT end dates to reflect potential retirement extensions.*

4.5 LABOR AND JUST TRANSITION FOCUS

Labor-related issues and just transition are both elements of resource procurement, bid evaluation, and portfolio development, whether in this NTP format or more traditional resource planning and procurement.

Just Transition Considerations

Starting with just transition considerations, Table 9 below shows the geographic location of projects in the proposed NTP portfolio by nameplate MW; it reflects a concentration of nameplate capacity in Morgan County (1,320 MW) and in the Denver Metro area (500 MW).

[21] Hrg. Ex. 118 in Proceeding No. 24A-0442E.

Table 9: Total Nameplate MW in Strategic Locations – Denver Metro, Pueblo, County, Morgan, Routt & Moffat County

Nameplate MW in Strategic Locations	Total MW
Denver Metro	500
Pueblo County	400
Morgan County	800
Routt County	0
Moffat County	0

As further discussed in Section 7.5 of this report, the NTP did not result in cost-effective, actionable bids in Routt County or Moffat County that we are recommending in Tier 1. While the Company did receive bids in these areas, none of them are proposed for approval as Tier 1 projects part of the NTP portfolio given the characteristics of these projects, which are shown in detail in Appendix A to this NTP Report. The Company is also recommending projects in both Pueblo County and Routt County as backup bid projects in Tier 2, as discussed in Section 5. These results further underscore the importance of ensuring a targeted focus on projects located in these areas in the upcoming JTS Base RFP and JTS Supplemental RFP, respectively.

Labor Considerations

With respect to labor-related requirements, compliance with Senate Bill 23-292 was mandatory as part of the NTP RFP. Project Labor Agreements ("PLAs") are a Senate Bill 23-292 compliance option, and Table 10 below shows which projects selected the PLA option. It is expected that *all* projects will qualify as Energy Sector Public Works projects under Senate Bill 23-292, which will require compliance with the law in the future. Furthermore, projects taking tax credits under the Inflation Reduction Act must also meet the requirements of Senate Bill 23-292, which will help to ensure the intent of Colorado law and the Commission's regulations is met by developers. Given the early stage in development of many of these projects, which is as expected given the later CODs of many projects, specific details of compliance plans are not known at this time. Table 10 shows each project in the proposed NTP portfolio, denotes which projects intend to use a PLA, and also has a column for any further comments on Senate Bill 23-292 compliance included as part of bid packages. The Company will be following up with bidders that did not address such compliance, and will move to backup/Tier 2 projects in place of these projects to the extent bidders do not certify their future intent to comply with applicable Senate Bill 23-292 requirements.

Table 10: Project Labor Agreement (PLA) and SB 23-292 Items for Selected Portfolio

Bid ID	Project Name	PLA?	Bidder Comments on SB 23-292 Compliance
099	[redacted]	Yes	Bidder is in compliance with SB 23-292.
114		No	Bidder is in compliance with SB 23-292.
046		No	Bidder is in compliance with SB 23-292.
055		No	Bidder is in compliance with SB 23-292.
089		Yes	Bidder is in compliance with SB 23-292.
053		No	Bidder is in compliance with SB 23-292.
054		No	Bidder is in compliance with SB 23-292.
127		No	Does not clearly demonstrate compliance with SB 23-292.
034		n/a	No information found.
135		No	Does not clearly demonstrate compliance with SB 23-292.
075		n/a	No information found.
057		No	Bidder is in compliance with SB 23-292.
068		No	Bidder is in compliance with SB 23-292.
097		No	Bidder is in compliance with SB 23-292.

4.6 RISKS AND CONSIDERATIONS FOR SELECTED PORTFOLIO

Of the 14 bids selected, Public Service identified the five bids listed below as presenting the most critical risks within the proposed NTP portfolio and is highlighting them here for Commission awareness. These assessments are based on internal due diligence, and the accompanying notes highlight key considerations for each project.

For Bid 089, the project faces transmission challenges. It is one of two bids proposing a line tap at the [redacted] line; however, Transmission has determined that a new line tap or a combined line tap with Bid 068 on the same line is not feasible while meeting the proposed COD at the end of 2028. The preferred alternative is interconnection at [redacted] with a revised COD of year-end 2029. However, this preferred interconnection introduces additional complexity since the switching station is currently being developed for a 2021 ERP & CEP resource and is not yet built, and the schedule for starting construction has not yet been determined. This scenario presents a significantly reduced likelihood of success and will require close coordination between the Company, bidder, and developer. For example, the projects may incur cost and schedule pressures associated with routing, permitting, and acquiring land rights for their new gen-tie lines to the new switching station location.

Given these challenges, and as explained in more detail below, the Company is proposing a designated backup bid project for Bid 089. The designated backup bid for this project

is Bid 003 if the POI change cannot be implemented, and the Company is asking for pre-approval of this designation due to the reduced probability of success coordinating with all the parties involved.

Bid 068 faces the same interconnection challenges as Bid 089, and is the other project that would require changing the POI to [redacted]. Again, in light of these bid-specific challenges and as explained in more detail below, the Company is proposing a designated backup bid project for Bid 068. The designated backup bid for this project is Bid 051, and the Company seeks pre-approval of this designation.

For Bid 127, the project involves a Company proposed combination line tap on the [redacted] line, which requires coordination with the bidder. Transmission believes this approach is feasible and aligns with the targeted COD of end of year 2029, giving the project a higher likelihood of success compared to other options. However, permitting remains in progress under the determination of no hazard ("DNH") process, and some turbines are located within military operating airspace, which could introduce additional regulatory considerations.

For Bid 075, the project faces the same transmission risk as Bid 127 and added technical compliance risks where the bidder does not currently meet all Company technical specifications for a BOT. Negotiations are underway to resolve these gaps if feasible. Despite these challenges, the project is considered to have a relatively high chance of success compared to other options.

Broader Risk Considerations on Energy Projects

In addition to the specific project-related risks, there are several more generalized risks that will need to be addressed in project development, negotiation, and/or implementation. These risks are not necessarily specific to the NTP portfolio, but apply to resource development in general and will continue to need investigation and possibly mitigation through the JTS RFPs as well as the NTP.

The first of these is the potential impact of extensive wind development, especially in Energy Resource Zone ("ERZ") 2, affecting the performance of existing and new wind projects through interactive waking effects. Bidders are expected to account for existing wind farms' impact in their capacity factor estimates, but the extent to which they have done so is unknown. Additionally, some new developments may negatively impact already established or in-development facilities, and those impacts have not yet been investigated or estimated.

Additionally, several of the new projects could have potential impacts to the Sand Creek Massacre and Amache Internment Camp National Historic Sites' viewsheds and have

related cultural sensitivities. Developers will need to work closely with the affected parties and ensure that projects are acceptable and considerate of these impacts.

Finally, there is an emerging concern that certain brands of batteries may have national security concerns vis-à-vis embedded communications protocols that may advantage certain foreign entities of concern ("FEOC"). While there are not currently prohibitions on specific vendors, that may change over time, and even potentially result in already-developed projects being required to shut down.

5. PROPOSED BACKUP/TIER 2 PROJECTS

The Company is also proposing backup/Tier 2 projects for the NTP to ensure flexibility and reliability in implementing the NTP portfolio. While the proposed NTP portfolio was selected based on cost, deliverability, and strategic considerations, there is always a risk that some Tier 1 projects may face delays or fail to meet permitting, interconnection, or financing milestones. The Company's approach in selecting backup/Tier 2 projects focused on identifying bids with strong permitting plans, secured site control, competitive pricing, and realistic schedules to ensure they could replace primary projects if needed without jeopardizing reliability or policy goals.

Table 11 below summarizes the 14 proposed backup projects.

Table 11: Proposed Backup Projects for NTP RFP

Bid ID	Project Name	Commercial Structure	Gen	Nameplate (MW)	Nameplate II (MW)	First Summer Gen Year	LEC ($/MWh)	LCC ($/kW-mo)	County	Point of Interconnection
118		PPA	Storage	400		2029			Routt	
113		PPA	Storage	300		2029			Adams	
007		PPA	Storage	250		2030			Weld	
009		PPA	Storage	250		2030			Morgan	
022		PPA	Storage	400		2029			Crowley	
047		PPA	Solar + Storage	250	250	2029			Cheyenne	
049		PPA	Solar + Storage	200	200	2029			Pueblo	
144		Own	Solar + Storage	260	260	2029			Morgan	
094		Own	Solar + Storage	450	450	2030			Adams	
003		PPA	Solar	500		2029			Kiowa	
023		PPA	Solar	400		2030			Crowley	
051		PPA	Wind	150		2029			Lincoln	
154		PPA	Wind	203		2030			Kiowa, Prowers	
077		Own	Wind	500		2030			Kiowa, Prowers	

** Designated backup for a specific recommended portfolio bid*

Bid 118 is a storage backup bid located in Routt County with a nameplate capacity of 400 MW. Bid 118 demonstrates strong compliance and low risk across key financial, contractual, and regulatory areas. It provides stable pricing with no adjustment clauses or early exit provisions, and meets security and performance requirements. Additionally, the bidder has completed environmental assessments, has a clear permitting plan, and shows proactive compliance with labor and tax credit requirements, making the project highly feasible and reliable for execution.

Bid 113 is the backup/alternate for Bid 114 as discussed in Section 4.1.

Bid 007 is a storage backup bid located in Weld County with a nameplate capacity of 250 MW. Bid 007 is a backup bid because it demonstrates strong compliance and low risk across all critical areas. It meets security and performance requirements, and provides stable pricing with no adjustment clauses or early exit provisions. The bidder has completed environmental and cultural assessments, has a permitting plan in place, and

shows readiness to meet labor and tax credit requirements, making the project feasible and reliable for execution.

Bid 009 is a storage backup bid, located in Morgan County with a nameplate capacity of 250 MW. Bid 009 is a backup bid because it demonstrates strong compliance and low risk across financial, contractual, and regulatory areas. It meets security and performance requirements, and provides stable pricing with no adjustment clauses or early exit provisions. The bidder has completed environmental and cultural assessments, has a clear permitting plan, and shows readiness to meet labor and tax credit requirements, making the project feasible and reliable for execution.

Bid 022 is a storage backup bid, located in Crowley County with a nameplate capacity of 400 MW. The project proposes to interconnect at the already planned [redacted] switching station using the [redacted] gen-tie. This would minimize construction delay risk and transmission costs. The bidder also has site control, is permitted in Crowley County, and has completed critical environmental, permitting, and site assessments with no major risks or delays identified. This demonstrates the project is viable and well developed. The proposal includes a plan to meet labor and tax credit requirements, including locking up major equipment through safe harbor actions, mitigating risk of future FEOC exposure.

Bid 047 is a solar + storage backup bid located in Cheyenne County with a total nameplate capacity of 500 MW. Bid 047 is a backup bid because it demonstrates strong compliance and low risk across all critical areas. It avoids imputed debt and derivative accounting issues, meets security and performance requirements, and provides clear pricing with no adjustment clauses or early exit provisions. The bidder has full site control, with completed permitting and environmental assessments, along with proactive tax credit compliance and Senate Bill 23-292 labor standards, making the project feasible and reliable for execution.

Bid 049 is a solar + storage backup bid located in Pueblo County with total nameplate capacity of 400 MW. Bid 049 is a strong backup because it shows comprehensive compliance and minimal risk across financial, contractual, and permitting requirements. It avoids imputed debt and derivative accounting issues, meets security and performance standards, and provides stable pricing with no adjustment clauses or early exit provisions. The bidder has full site control with completed permitting and environmental assessments. Further, the bidder demonstrates readiness for tax credit compliance, making the project feasible and reliable for execution.

Bid 144 is a solar + storage backup bid located in Morgan County with a total nameplate capacity of 520 MW. The project carries both transmission and credit-related risks. The bid was proposed as a transmission line tap, but Transmission is recommending a reroute

to [redacted] or [redacted]. While this alternative is technically possible, it introduces uncertainty and is considered high risk. Additionally, the developer has not provided audited financial statements, and the bank they intend to use is not yet approved, creating credit concerns. Technical specification conformity will also need to be verified to ensure compliance.

Bid 094 is a solar + storage backup bid located in Adams County with a total nameplate capacity of 900 MW. It has a beneficial location inside the Denver Metro Constraint and could offset congestion in that constraint. The bid has solid due diligence reviews and limited development risk. This lower risk profile and the project's locational benefits support its inclusion as a backup bid here.

Bid 003 is designated as a solar backup bid for Bid 089 and is located in Kiowa County with a nameplate capacity of 500 MW. The bid would be favorable as a backup because it shows strong compliance with key financial, contractual, and regulatory requirements, including adherence to most Model PPA standards. It also demonstrates readiness on permitting, environmental planning, and tax credit eligibility, while maintaining price clarity and security provisions, indicating low risk and high feasibility for execution.

Bid 023 is a solar backup bid, located in Crowley County with a nameplate capacity of 400 MW. It demonstrates full compliance with contractual, environmental, and labor requirements while minimizing financial and regulatory risks. Additionally, it shows proactive procurement, safe harboring for tax credit qualification purposes, and a feasible schedule, all of which lead to confidence in project execution.

Bid 051 is positioned as a designated wind backup bid for Bid 068. The project is located in Lincoln County with a nameplate capacity of 150 MW. Bid 051 has low risk across all critical areas. It meets security and performance requirements and provides stable pricing with no adjustment clauses or early exit provisions. The bidder has secured site control, outlined a realistic permitting approach, and committed to labor and tax credit compliance, while also showing financial strength and a feasible schedule. These factors indicate a lower level of execution risk, making it a solid contingency option as a designated backup bid.

Bid 154 is a wind backup bid located in Kit Carson County with a nameplate capacity of 203 MW. Bid 154 is a good backup because it demonstrates low risk across financial, contractual, and permitting requirements. It meets security and performance standards and provides stable pricing with no adjustment clauses or early exit provisions. The bidder has completed site characterization, developed a robust permitting plan, secured most site control, and outlined a proactive community engagement approach. Additionally, tax credit eligibility and bonus adders are substantiated through Company

review to date, and the schedule appears feasible, making this a solid contingency option in the event of project failures in the proposed NTP portfolio.

Bid 077 is a wind backup bid located in Kiowa and Prowers County with a nameplate capacity of 500 MW. Bid 077 would be a good backup because it demonstrates low risk across financial, environmental, and permitting requirements. The bidder has certified no accounting issues, completed extensive wildlife surveys and provided a clear permitting plan with favorable local government feedback. Site control is largely secured, the schedule is feasible, and tax credit eligibility is confirmed. The bidder has not yet made direct communications with the National Park Service regarding the Amache Relocation Center which is in proximity to their site, or the local tribes related to the Sand Creek Massacre site but is aware of the need to engage on both topics. They have stated they are committed to doing so, though the Company believes the current status of communications adds a level of risk to the project.

6. BID EVALUATION AND SELECTION PROCESS

The goal of the NTP bid evaluation process was to vet as many of the 161 bids as possible to move them to the point where the Company could consider them for the final portfolio. The Company considered a bid ready for final portfolio consideration when it had verified pricing, or calculated revenue requirements, and a detailed due diligence review.

Within approximately 45 days of bid opening, the Company had moved 92 of the 161 bids from an "unknown" state to a fully vetted and costed state. Completing this expedited evaluation required a rigorous, efficient approach.

The Company moved bids through its evaluation process by assessing, ranking, and selecting them according to the following criteria:

- **Completeness**, as assessed through an initial inventory of each bid package
- **Price**, as measured by each bid's levelized cost of energy or capacity
- **Quality**, as assessed through due diligence by Company subject matter experts
- **Holistic portfolio alignment,** as assessed by considering how specific bids' interconnection, deliverability, operations, and locational attributes either support or detract from a portfolio of bids

The evaluation began with a completeness review of each bid, followed by an initial pricing assessment to prioritize bids for due diligence, followed by detailed due diligence reviews, followed by the holistic portfolio analysis and alignment.

Throughout the evaluation, the Company worked with bidders to clarify and correct project details and address due diligence concerns. Below, we describe each stage of the NTP bid evaluation process in more detail.

6.1 BID COMPLETENESS REVIEW

The goal of the completeness review was to assess the degree to which bid packages contained the information required to determine eligibility and calculate levelized costs. Bids that did not meet the minimum requirements of the RFP were removed in this stage. Among these were several bids for extensions of long-standing hydro PPA's that will be handled through separate negotiations.

The completeness review checked whether bid packages contained basic information such as a completed Bid Form and a Narrative document describing important project information, including schedule, equipment procurement plan, energy production profile,

and permitting plans. The minimum requirements for bid submission were provided to all bidders in Section 4 of the NTP RFP document, and the completeness review ensured that all required forms and topics clearly discussed in Section 4.2 were present before advancing bids to due diligence.

When the Company identified critical information missing from bid packages, it communicated with bidders via email to request the information. All email correspondence with bidders was tracked to ensure transparency and maintain a complete record throughout the evaluation process.

In this stage, the Company worked as quickly as possible to obtain the required information for as many bids as possible to calculate levelized costs.

6.2 BID PRICE COMPARISON

The goal of the price comparison stage was to surface the most cost-effective bids to advance to the resource-intensive due diligence review stage.[22] In this stage, the Company calculated levelized costs for as many bids as possible. Using ranked prices, the Company could prioritize and advance the most cost-effective bids to the resource-intensive due diligence stage.

The Company calculated a LEC ($/MWh) for energy resources (e.g., renewable or renewable hybrid generators) and a LCC ($/kW-month) for capacity resources (e.g., dispatchable and standalone storage projects). This allowed for a direct comparison of bids within technology types regardless of bid characteristics such as COD, ownership structure, or nameplate. The Company calculated an LEC for each energy resource bid by dividing the NPV of its annual costs by the NPV of its annual generation. The Company calculated an LCC for each capacity resource bid by dividing the NPV of its annual costs by the NPV of its annual capacity available.

For PPA bids, the Company used annual energy payments as the NPV of costs input for energy resources and annual capacity payments as the NPV of costs input for capacity resources. For ownership projects, including Company Self-Build and BOT projects, the Company used a 20- to 40-year series of revenue requirements, which it calculated in alignment with the assumed useful life of the resource type, as the NPV of costs input.

As it takes multiple weeks to calculate actual revenue requirements for ownership bids, the Company calculated initial estimated revenue requirements for ownership bids to screen them for early advancement to due diligence. The Company estimated revenue

[22] Hrg. Ex. 101, Attachment JWI-2 (Volume 2), Rev. 1, at 219.

requirements using levelized fixed charge rates ("LFCR")[23] derived from capital costs and final revenue requirements in the 2022 All-Source RFP. This allowed ownership bids to be included in the initial ranking of bids to be sent to due diligence.

In the final price ranking, all bids' levelized cost value included transmission costs and either their PPA price or final revenue requirements. In the final ranking, the Company used different variations of levelized cost calculations depending on technology type. In the tables presented in this report, these are shown as "scoring levelized costs".

For standalone wind and solar projects, this was simply the normal LEC, which is NPV of annual costs divided by the NPV of annual generation as described above.

For hybrid projects, however, a modified LEC was used to capture the value of the storage component and to be able to compare projects with different storage configurations, including both duration and size. For example, a standard LEC calculation would divide the cost of the whole hybrid and divide it by the NPV of the generation of the renewable portion. The LEC would inevitably be higher than any standalone renewable project, the LEC of 4-hour battery projects would be higher than 2-hour projects, the LEC of augmented batteries would be higher than ones that allow the capacity to degrade, and projects with larger batteries relative to the solar would also show higher LECs. However, longer duration and larger batteries also provide more system value, and this is ignored in a standard LEC calculation, and they would likely not be selected based on the apparently higher LEC.

To correct this, the Company used the method proposed in Mr. Landrum's Direct Testimony in the JTS (Proceeding No. 24A-0442E).[24] Hybrid bids were ranked using an adjusted LEC determined by first determining the capacity value of the capacity resource by multiplying the surplus capacity credit by the ELCC adjusted firm capacity of the capacity component of the bid. This would be the storage component. This capacity value is deducted from the notional costs of the bid on a year-by-year basis, and an adjusted LEC is calculated on the remaining costs divided by the energy supplied, on a net present value basis. This adjusted LEC is only used in comparing and ranking hybrid bids, and not comingled with standard LEC types of bids. The surplus capacity value is derived from the updated generic CT costs presented in the Company's Rebuttal Case[25] in the JTS using the standard economic carrying charge calculation template used to develop EnCompass inputs in ERPs. The resultant values on a $/firm kW basis are shown below in Table 12:

[23] LFCR is a commonly used metric in Resource Planning, and is simply the ratio of the annual levelized revenue requirement divided by the initial capital expenditure.
[24] Hrg. Ex. 102, Direct Testimony and Attachments of Jon T. Landrum, at 65.
[25] Hrg. Ex. 118, Rebuttal Testimony and Attachments of Jon T. Landrum, Attachment JTL-10.

Table 12: Capacity Credit Values for NTP RFP

Year	$/kW-Year	$/kW-Month
2025	$ 190.43	$ 15.87
2026	$ 195.18	$ 16.27
2027	$ 200.05	$ 16.67
2028	$ 205.05	$ 17.09
2029	$ 210.17	$ 17.51
2030	$ 215.42	$ 17.95
2031	$ 220.80	$ 18.40
2032	$ 226.31	$ 18.86
2033	$ 231.96	$ 19.33
2034	$ 237.75	$ 19.81
2035	$ 243.69	$ 20.31
2036	$ 249.78	$ 20.81
2037	$ 256.01	$ 21.33
2038	$ 262.40	$ 21.87
2039	$ 268.96	$ 22.41
2040	$ 275.67	$ 22.97
2041	$ 282.56	$ 23.55
2042	$ 289.61	$ 24.13
2043	$ 296.84	$ 24.74
2044	$ 304.26	$ 25.35
2045	$ 311.85	$ 25.99
2046	$ 319.64	$ 26.64
2047	$ 327.62	$ 27.30
2048	$ 335.80	$ 27.98
2049	$ 344.19	$ 28.68
2050	$ 352.78	$ 29.40

For standalone storage resources and thermal resources, the NPV of firm capacity was used instead of nameplate, incorporating resource accreditation from the 2024 Resource Adequacy Study so that value to the system would be considered instead of just upfront capital costs. In this way, an 8-hour storage resource could be more directly considered against a 4-hour storage resource, or a thermal resource with lower forced outage rates could be directly compared against a similar unit of lesser reliability.

Each of the scoring levelized costs included estimates for transmission interconnection costs that were provided by the transmission due diligence team. This is what the Company calls an “All-In” levelized cost.[26]

6.3 QUALITY / DUE DILIGENCE EVALUATION

The goal of the quality, or due diligence, stage of the evaluation was to surface the highest-quality, most feasible projects among the subset of most cost-effective projects.

[26] Includes only interconnection costs that are attributable to individual bids. Network upgrade costs that are determined by more in depth analysis are a portfolio level cost. See Section 6.3 for details on how interconnection costs were estimated.

This stage assessed whether bids met the technical, financial, and regulatory standards necessary for inclusion in a selected portfolio. The Company's pricing evaluation prioritized the 92 most cost-effective bids for due diligence review to focus SMEs' limited time within the expedited review on the most cost-effective bids.

Qualitative Review

The due diligence stage of the NTP was the most time- and resource-intensive stage of the evaluation because it involved detailed reviews of bid packages by over 40 Company SMEs across 11 different review categories, including Contract Accounting, Credit Risk, Environmental Services, Siting and Land Rights, Technology, Transmission, and Tax organizations, among others.

In this stage, SMEs used a standard set of questions specific to their review category to evaluate bid packages, identify potential issues, submit clarification questions, and assign a status indicator to each project — green, yellow, or red — based on their assessment. Green indicated no concern, yellow indicated a cautionary issue, and red indicated a significant concern.

Company SMEs reviewed 92 bids and answered over 5,000 due diligence questions in roughly 30 calendar days. The questions aimed to vet bids thoroughly to ensure they demonstrated sufficient development progress to achieve commercial operation before the end of 2029, minimize risks to project pricing, and meet fundamental criteria for successful projects, such as:

- Securing the federal tax credits
- Proving long lead time equipment would be procured to support COD
- An understanding of the Model PPA contract and a willingness to negotiate terms in good faith and commit to as-bid pricing
- Compliance with Company ownership technical specifications (for BOTs)
- A comprehensive permitting and site acquisition plan
- A feasible interconnection plan and the ability to deliver to the Public Service system
- A clear plan to address a major environmental concern

Cost Development

During the due diligence review, there were three areas critical to understanding project costs that could be used for bid comparison.

First, the technology SMEs reviewed ownership bids to estimate ongoing capital and O&M costs associated with owning/operating the facility. Examples of this step include estimating battery augmentation frequency and costs based on the technical information provided in the bid, or adding capital spares for critical equipment such as MPTs. They also reviewed the construction schedule and added costs for overheads such as project oversight during the construction phase.

Second, the Gas Planning team reviewed thermal bids to determine added fixed and variable fuel costs to provide natural gas to each proposed turbine.

Finally, the transmission due diligence team reviewed each bid's proposed transmission plan and estimated interconnection costs needed to deliver the project. This review was especially time intensive, as it required a review of each proposed POI.

There were two types of interconnection costs that were reviewed that had a material impact on the levelized cost of a bid. Transmission Provider Interconnection Facilities ("TPIF") consist of infrastructure that connect the end of a bid's gen-tie to the POI. These costs are not recovered through a transmission tariff and are attributed to the generator and paid for by the bidder. Without an interconnection study, bidders could not know what their TPIF costs would actually be, and therefore used estimates by voltage class provided by the Company in the RFP document. The due diligence team was responsible for revising those TPIF costs in the event Public Service was the transmission provider.

PSCo-Owned, PSCo-Funded ("POPF") facilities represent the first level of network upgrades required for interconnection and are typically upgrades at a substation needed for interconnection, or a new switching station to interconnect at a new line tap. These costs are not portfolio level costs and are attributed directly to individual bids. These estimates were dependent on multiple factors, including the voltage, whether the interconnection was at an existing substation or a new line-tap, and if upgrades at a substation were required at the proposed location (such as adding breakers).

Due Diligence Results

Upon completion of the due diligence review, the Company could identify the most cost-effective *and* highest-quality, or lowest risk, bids for consideration in the selected or backup portfolio. Within this subset of projects, the Company then began a holistic portfolio analysis, as discussed in the next section.

6.4 HOLISTIC PORTFOLIO ANALYSIS

During initial portfolio development, the Company filtered bids that had been through due diligence by technology type and then sorted by lowest cost, using the applicable "scoring metric" for each technology as described in Section 6.2. The Company used this ranked price list to build an initial portfolio, bid by bid, that achieved the NTP targets. The Company passed on bids that had significant issues identified in due diligence.

Following this initial portfolio development, the Company began to conduct a holistic review of the portfolio that considered:

- The overall transmission interconnection and delivery feasibility of the portfolio, considering real-world limitations like the Denver Metro Constraint
- Project development that supports Just Transition communities
- Portfolio risk mitigation

When considering project swaps during the holistic portfolio analysis, the Company weighed whether the marginal cost of a bid that addressed a portfolio matter was justified.

Transmission Interconnection and Deliverability Evaluation

The evaluation team engaged the transmission due diligence team in the holistic portfolio analysis to review the station network upgrades needed to interconnect the bids across the portfolio.

The goal of engaging Transmission in the holistic portfolio analysis was to maximize the likelihood of the selected portfolio's projects achieving their COD in light of real-world interconnection timelines and deliverability challenges such as the Denver Metro Constraint.

First, the teams assessed whether there is sufficient capacity at a bid's POI and, if not, whether the POI could be upgraded to reasonably accommodate the project. Second, the teams reviewed the full portfolio to assess its overall feasibility and deliverability. The team flagged multiple cost-effective and high-quality projects in this stage because they proposed line taps with interconnection timelines incompatible with their CODs. In instances where projects proposing line taps were feasible from a timeline perspective, the teams discussed the tradeoffs between NTP portfolio costs, additional transmission system costs, and additional operational risks as compared to NTP portfolios with more projects interconnecting at existing substations.

These discussions led to the continued inclusion of Bids 089 and 068, which would not have been able to meet their CODs should a new switching station be needed for each project on the [redacted] line. While still at risk, the proposed alternate route would reduce overall transmission costs and keep these cost-effective projects in the portfolio. In another case, the Company identified multiple bids proposing a line tap of the [redacted] line in a similar vicinity. After reviewing project locations, proposed CODs, and impacts to operations, the team was able to propose a combined switching station for Bids 127 and 075 that reduced total costs, the number of cuts into a main segment of the CPP, and development timelines. Strictly looking at the POPF costs provided in Appendix A, these innovative solutions could save approximately $67 million in portfolio upgrade costs.[27]

Also during this process, the evaluation team conducted a focused analysis on bids proposing to interconnect on the unconstrained side of the Denver Metro Constraint to support system operations. After considering cost compared to less expensive storage project, the team ultimately selected Bid 114, a 300 MW 4-hour storage resource, for its strategic location within the Denver Metro Constraint. Other bids within the Denver Metro Constraint were considered and eventually included on the backup bid list. Should less expensive bids currently in the portfolio be unsuccessful, the cost of adding more projects within the Denver Metro area becomes more justifiable.

Ultimately, the Company has proposed a portfolio that balances generator costs and transmission system costs while mitigating transmission system operational risks through the inclusion of feasible line tap projects capable of sharing a switchyard.

Just Transition Communities

The goal of the Just Transition communities evaluation was to emphasize the consideration of projects in Pueblo, Routt, Morgan, and Moffat Counties, consistent with the Commission's directives in the NTP Initiation Decision,[28] even if those projects were less cost-effective than similar projects located outside of those communities.

The first step in emphasizing the consideration of projects in Just Transition communities in the NTP was to simply identify and track projects proposed in these communities, which the Company began doing immediately upon NTP bid receipt.

Although the Company made a concerted effort to incorporate Just Transition communities into our evaluation, other critical factors—such as deliverability, cost, and overall risk—ultimately prevented many projects in these areas from being selected. While the inclusion of Just Transition communities was an important consideration, many

[27] This calculation is strictly based on switching station upgrade comparisons. The alternate route would require varying degrees of changes to the proposed gen-tie of each bid, offsetting some of the savings.
[28] *See* Decision No. C25-0652-I, at ¶ 30, Proceeding No. 21A-0141E.

projects located in these areas presented risks that outweighed their benefits. As a result, these bids were not deemed viable for inclusion in the proposed NTP portfolio. As discussed above, although the proposed NTP portfolio contains one Tier 1 project in Pueblo County and Morgan County, but none in Routt County or Moffat County, the Company is recommending projects in Pueblo County and Routt County as backup bid projects in Tier 2.

Operations Considerations

When EnCompass optimizes a portfolio in capacity expansion modeling, one of the considerations is the specific ELCC curve (accredited capacity) and the production profile (estimated energy) of a project, which assesses the benefit it provides to the needs of the system.

Without modeling, the team still needed to review the location of the projects in the portfolio with an eye on resource mix. For example, if all of the lowest cost solar bids were located in the same region, the team would consider the value of including other diverse resources instead.

Fortunately, the lowest cost bids were also geographically diverse in nature. Tables 13 and 14 below show the Solar Resource Zone ("SRZ") and ERZ (for wind resources). The team did not determine that any bids needed to be exchanged for the purpose of adding a different resource.

Table 13: Recommended Portfolio Geographic Diversity by SRZ/ERZ

Bid ID	Status	Project Name	Commercial Structure	Gen	Nameplate Solar/Wind (MW)	SRZ/ERZ	SRZ/ERZ % of Applicable Gen Nameplate (MW)
046	Selected	[redacted]	PPA	Solar + Storage	400	NFR	
				Total Nameplate (MW) - SRZ: NFR	**400**		**36%**
055	Selected		PPA	Solar + Storage	200	SFR	
				Total Nameplate (MW) - SRZ: SFR	**200**		**18%**
089	Selected		PPA	Solar	500	SE	
				Total Nameplate (MW) - SRZ: SE	**500**		**45%**
				Total Nameplate (MW) - All SRZ Zones	**1,100**		
054	Selected		PPA	Wind	214	1	
034	Selected		PPA	Wind	301	1	
135	Selected		PPA	Wind	60	1	
057	Selected		PPA	Wind	23	1	
				Total Nameplate (MW) - ERZ 1	**597**		**22%**
053	Selected		PPA	Wind	21	2	
127	Selected		Own	Wind	608	2	
075	Selected		Own	Wind	500	2	
068	Selected		PPA	Wind	500	2	
				Total Nameplate (MW) - ERZ 2	**1,629**		**60%**
097	Selected		Own	Wind	475	3	
				Total Nameplate (MW) - ERZ 3	**475**		**18%**
				Total Nameplate (MW) - All ERZ Zones	**2,702**		

Table 14: Backup Bids Geographic Diversity by SRZ/ERZ

Bid ID	Status	Project Name	Commercial Structure	Gen	Nameplate Solar/Wind (MW)	SRZ/ERZ	SRZ/ERZ % of Applicable Gen Nameplate (MW)
047	Backup	[redacted]	PPA	Solar + Storage	250	NFR	
144	Backup		Own	Solar + Storage	260	NFR	
094	Backup		Own	Solar + Storage	450	NFR	
				Total Nameplate (MW) - SRZ: NFR	**960**		**47%**
003	Backup		PPA	Solar	500	SE	
023	Backup		PPA	Solar	400	SE	
				Total Nameplate (MW) - SRZ: SE	**900**		**44%**
049	Backup		PPA	Solar + Storage	200	SFR	
				Total Nameplate (MW) - SRZ: SFR	**200**		**10%**
				Total Nameplate (MW): All SRZ Zones	**2,060**		
051	Backup		PPA	Wind	150	2	
154	Backup		PPA	Wind	203	2	
				Total Nameplate (MW) - ERZ 2	**353**		**41%**
077	Backup		Own	Wind	500	3	
				Total Nameplate (MW) - ERZ 3	**500**		**59%**
				Total Nameplate (MW): All ERZ Zones	**853**		

Another consideration was the amount of battery storage being added to the system. Battery storage has clear benefits for the operation of a system with heavy renewable integration, but there are also challenges to operations when adding large amounts of energy limited resources to cover net peak loads and provide reserve benefits.

Without EnCompass modeling, it was difficult to determine a natural cut line for the amount of storage resources in the portfolio. The evaluation team with input from Commercial Operations determined that 1,000 MW would be a reasonable cap for storage, noting the ELCCs studied by E3 in the 2024 Resource Adequacy Study indicated a significant drop-off in ELCC after 1,000 MW, as well as a desire to not overextend investment into storage prior to real experience in managing it as a system resource.

Based on Table 15 below, after adding 1,000 MW of solar, the accredited capacity of the next storage resource would be reduced by almost half compared to the first tranche of 4-hour storage added in the portfolio. The 900 MW of storage included within the portfolio fits comfortably under the cap. While 8-hour storage has a 91% ELCC for the first 500 MW, the Scoring LCC utilizes accredited or firm capacity for its calculations, and the lowest cost 8-hour resource was still not cost-effective compared to cheaper 4-hour storage, so it was not forced into the portfolio.

Table 15: 4-Hour Storage Marginal ELCCs

Marginal ELCC (%), summer				
Tranche Size	0	0-500	500-1000	1000-2000
Storage (4hr)	-	60%	46%	36%

Portfolio Risk Mitigation

As a final example of what went into the holistic analysis, the team worked with multiple members of the due diligence team to weigh risks inherent to the portfolio. No project is perfect, and all come with some level of risk. The team needed to weigh if the risks were not only reasonable for inclusion, but what the backup plan would be should the project(s) ultimately fail. Some examples of this include:

- The aforementioned Bids 089 and 068 still carry more risk to successful interconnection given the number of parties needed to work together to arrive at a combined interconnection. In response to this elevated risk, the Company designated two direct replacements from the backup bid list that it would be ready to act upon quickly should negotiations fall through.

- The Company initially considered Bid 134 (thermal PPA) for inclusion in the recommended portfolio due to its strategic location within the Denver Metro Constraint, low cost relative to the remaining the thermal bids, and increased ownership diversity of thermal projects. However, as discussed in Section 7.5 of the report, the significant pricing, contracting and development risks of the project led to its ultimate exclusion from the portfolio.

Section 7 of this NTP Report presents a high-level discussion of the projects that were not selected for inclusion in the final portfolio.

7. PROJECTS NOT SELECTED FOR ACQUISITION

Throughout this section, projects not selected for the proposed NTP portfolio are denoted via gray highlights and followed by accompanying notes summarizing key factors that led to those bids being excluded. Projects are addressed based on technology type, and the cost figures listed for each technology illustrate where the selected projects fell in the price stacking exercise performed by Public Service. The purpose of each subsection below is to show lower-cost projects, or those close in pricing to the selected and backup projects, that were ultimately not selected and explain why these projects are not being proposed for development or acquisition by the Company.

7.1 SOLAR PROJECTS

Bid ID	Status	Project Name	Commercial Structure	Gen	Nameplate (MW)	First Summer Gen Year	LEC ($/MWh)	County	Point of Intersection
089	Selected	[redacted]	PPA	Solar	500	2029	[redacted]	Kiowa	[redacted]
003	Backup		PPA	Solar	500	2029		Kiowa	
023	Backup		PPA	Solar	400	2030		Crowley	
059	Reviewed		PPA	Solar	500	2029		Kiowa	
102	Reviewed		Own	Solar	400	2029		Kit Carson	
067	Reviewed		PPA	Solar	300	2029		Morgan	
064	Reviewed		Own	Solar	580	2030		Kiowa	
079	Reviewed		Own	Solar	400	2030		Weld	

In general, no projects were passed over in the solar technology group, and projects were simply not selected due to being below the cut line. However, primary due diligence review findings on these higher cost projects are presented below.

Bid 059 is not as price competitive as other bids. A COD before the end of 2029 is significantly at risk on the [redacted] line.

Bid 102 presents unresolved land-use issues, as a portion of the project area includes State land and the bidder has not clarified whether they will avoid these areas or secure necessary easements. The project still has outstanding environmental and permitting risks, and a new line tap here would have scheduling risks.

Bid 067 presents significant uncertainties, including unresolved land-use and permitting issues, lack of requirement environmental and technical studies, and non-compliance with Company's design standards. Despite its higher voltage, the [redacted] line tap may still face regional transmission congestion, limited available capacity, and could require costly network reinforcements or reactive power upgrades to reliably accommodate large new interconnections.

Bid 064 carried multiple unresolved environmental and permitting risks, including lack of wildlife consultation for species of concern, such as lesser prairie chickens. Transmission constraints, unclear construction milestones, and non-compliance with Company's technical standards introduce significant uncertainty that could lead to delays and increased costs.

Bid 079 is in Weld County and lacks critical development documentation and has outstanding environmental and permitting risks. The proposal does not meet technical standards and key procurements steps such as EPC selection and PV module agreements remain unresolved.

7.2 SOLAR PLUS STORAGE PROJECTS

Bid ID	Status	Project Name	Commercial Structure	Gen	Total Nameplate (MW)	Nameplate (MW) II	First Summer Gen	LEC ($/MWh)	County	Point of Intersection
046	Selected	[redacted]	PPA	Solar + Storage	400	400	2029	[redacted]	Morgan	[redacted]
055	Selected		PPA	Solar + Storage	200	200	2029		Pueblo	
047	Backup		PPA	Solar + Storage	250	250	2029		Cheyenne	
049	Backup		PPA	Solar + Storage	200	200	2029		Pueblo	
065	Reviewed		PPA	Solar + Storage	199	199	2030		Prowers	
043	Reviewed		PPA	Solar + Storage	380	380	2029		Pueblo	
131	Reviewed		PPA	Solar + Storage	400	400	2030		Morgan	
091	Reviewed		PPA	Solar + Storage	125	125	2029		Saguache	
144	Backup		Own	Solar + Storage	260	260	2029		Morgan	
094	Backup		Own	Solar + Storage	450	450	2030		Adams	
136	Reviewed		PPA	Solar + Storage	400	200	2030		Adams	
040	Reviewed		Own	Solar + Storage	300	300	2030		Pueblo	
095	Reviewed		Own	Solar + Storage	300	300	2029		Adams	
096	Reviewed		Own	Solar + Storage	300	300	2029		Morgan	
033	Reviewed		PPA	Solar + Storage	199	199	2029		Adams	
038	Reviewed		Own	Solar + Storage	300	300	2030		Adams	
126	Reviewed		Own	Solar + Storage	215	125	2029		Routt	
107	Reviewed		Own	Solar + Storage	300	300	2030		Cheyenne	
106	Reviewed		Own	Solar + Storage	200	200	2030		Arapahoe	
002	Reviewed		Own	Solar + Storage	250	125	2029		Pueblo	
015	Reviewed		Own	Solar + Storage	150	100	2029		Adams	

Bid 065 proposes reduced performance obligations for Committed Energy, Availability, and Events of Default compared to Model PPA agreements, creating contractual and reliability risk. Further, the project's scoring levelized cost is higher than both selected and backup bid projects.

Bid 043 is not price competitive and still has outstanding development and environmental permitting flags.

Bid 131 introduces financial complexity because capacity payments will result in imputed debt impacts, increasing the Company's leverage position. Additionally, the 18-year term is likely to be classified as a finance lease given the assumed 20-year economic life, which could negatively affect balance sheet treatment and regulatory considerations. Further, the [redacted] line tap is not favorable from a bid selection perspective because it introduces reliability and maintenance challenges, requires

extended outages for installation, and limits future transmission capacity compared to a full substation interconnection.

Bid 091 introduces financial and accounting concerns because capacity payments will create imputed debt impacts, increasing the Company's leverage position. Additionally, the 18-year term is likely to be classified as a finance lease given the assumed 20-year economic life, which could negatively affect balance sheet treatment and regulatory compliance. Moreover, a line tap at the [redacted] line is not favorable from a bid selection perspective because it adds reliability and maintenance challenges, requires extended outages for installation, and limits future transmission flexibility compared to a substation interconnection.

The below projects were largely not considered due to price being above the cut line, however key due diligence findings for each project are provided.

Bid 136 carries significant development and permitting risk because critical preconstruction work—including site characterization, environmental surveys, cultural assessments, and wildlife consultations—has not been completed. Additionally, the inclusion of capacity payments creates imputed debt impacts, and the 18-year term is likely to be classified as a finance lease, adding financial complexity.

Bid 040 lacks critical assessments and modeling, including cultural survey and glint/glare analysis, leaving potential impacts to communities and landowners unaddressed. In addition, the bid failed to provide proof of site control, equipment procurement plans, security measures, and a site layout, creating significant constructability and compliance risks.

Bid 095 failed to provide the required land use permitting documentation, leaving the feasibility of the permitting approach unverified. Without this critical information, there is no assurance that the proposed generation technology can be legally and practically implemented at the specified location, creating significant regulatory and project execution risks.

Bid 033 fails to meet critical financial and contractual compliance requirements. The bidder did not provide the required three years of audited financial statements, leaving its financial stability unverified. Additionally, the bid includes redlines to key performance requirements in the Model PPA—such as mechanical availability and committed energy thresholds—and introduces pricing deviations related to battery round-trip efficiency losses. These changes materially impact reliability, resource adequacy, and cost risk to the customer, making the proposal non-compliant with RFP standards. Moreover, the [redacted] Line Tap is not favorable because it introduces high interconnection costs and potential reliability concerns without offering significant system benefits.

Bid 038 has not completed cultural, historic, or impacted community assessments, leaving potential risks to sensitive areas and communities unknown. Physical and cyber/data security measures were not addressed, posing operational and regulatory concerns. In addition, the [redacted] Line Tap is not favorable because of the extremely high voltage level and associated infrastructure requirements pose significant cost, complexity, and reliability challenges compared to more practical alternatives.

Bid 126 relies on the [redacted] Line Tap, which introduces high interconnection costs and potential reliability challenges while providing minimal system benefits.

Bid 107 has failed to provide critical documentation, including updated constructability analysis, site layout, environmental assessments, and plans to address community opposition, leaving major feasibility and compliance risks unresolved. Additionally, the project cannot meet required tax credit deadlines, and key modeling and due diligence responses remain incomplete or unanswered, creating uncertainty around cost, schedule, and regulatory compliance.

Bid 106 faces major permitting and transmission challenges, including unclear gen-tie approval, lack of land control, and metro-area constraints requiring additional infrastructure upgrades. Furthermore, the absence of a site layout and failure to meet tax credit deadlines create significant constructability and financial risks.

Bid 002 fails to meet critical technical and compliance requirements: glint/glare modeling and Phase I environmental assessment were not completed; land ownership history raises permitting concerns; and major technical exceptions—including non-approved inverters, inadequate MPT ratings, and unacceptable equipment changes—do not align with Company standards. Additionally, the bid's levelized cost is more than double that of the second-ranked solar + storage project, making it economically uncompetitive.

Bid 015 lacks a completed Phase I Environmental Site Assessment, leaving contamination risks unaddressed, and future compliance impacts remain unknown until pre-construction surveys are complete. Additionally, the bidder has not demonstrated a plan to comply with FEOC rules for tax incentives, and its levelized cost is three times higher than the second-ranked solar + storage project, making it economically and regulatory risky.

7.3 WIND PROJECTS

Bid ID	Status	Project Name	Commercial Structure	Gen	Nameplate (MW)	First Summer Gen Year	LEC ($/MWh)	County	Point of Intersection
053	Selected	[redacted]	PPA	Wind	21	2027	[redacted]	Lincoln	[redacted]
054	Selected		PPA	Wind	214	2028		Logan	
127	Selected		Own	Wind	608	2030		Kit Carson	
034	Selected		PPA	Wind	301	2028		Weld	
135	Selected		PPA	Wind	60	2028		Logan	
075	Selected		Own	Wind	500	2030		Yuma, Kit Carson	
057	Selected		PPA	Wind	23	2030		Logan	
068	Selected		PPA	Wind	500	2029		Lincoln	
097	Selected		Own	Wind	475	2030		Kiowa	
051	Backup		PPA	Wind	150	2029		Lincoln	
154	Backup		PPA	Wind	203	2030		Kit Carson	
077	Backup		Own	Wind	500	2030		Kiowa, Prowers	
157	Reviewed		PPA	Wind	75	2030		Logan	
048	Reviewed		PPA	Wind	175	2028		Kit Karson	
012	Reviewed		Own	Wind	522	2030		Yuma	

Wind projects were selected in ascending price order, so there are no skips to explain away. However, some key due diligence findings for projects near but below the cut line are provided below.

Bid 157 presents major risks to reach commercial operation due to a failure to meet creditworthiness requirements, a lack of clarity on FEOC compliance and Beginning Of Construction timing, reliance on preliminary activities that may not satisfy IRS physical work and continuity tests, and a construction start date misaligned with tax credit eligibility, despite plans for third-party verification.

Bid 048 is not favorable because key development activities such as noise, flicker, and glare modeling have not been conducted and Federal Aviation Administration ("FAA") approvals, including Determination of No Hazard ("DNH") filings, are only scheduled but remain incomplete. These gaps create significant uncertainty around environmental compliance and regulatory timelines, increasing the risk of delays and additional costs.

Bid 012 has critical milestones such as DNH filings, Phase I Environmental Site Assessment, and noise/glare modeling have not been completed, and site control remains unclear with a 45-mile gen-tie and a new substation requirement in Washington County. Additionally, interconnection at either the [redacted] or [redacted] taps could involve significant transmission upgrades and congestion risks, further increasing cost and schedule uncertainty.

7.4 STANDALONE STORAGE PROJECTS

Bid ID	Status	Project Name	Commercial Structure	Gen	Nameplate (MW)	First Summer Gen Year	LCC ($/kW-mo)	County	Point of Intersection
083	Reviewed	[redacted]	PPA	Storage	60	2029	[redacted]	Kit Carson	[redacted]
118	Backup		PPA	Storage	400	2029		Routt	
113	Backup		PPA	Storage	300	2029		Adams	
117	Reviewed		Own	Storage	400	2029		Routt	
007	Backup		PPA	Storage	250	2030		Weld	
028	Reviewed		PPA	Storage	600	2030		El Paso	
009	Backup		PPA	Storage	250	2030		Morgan	
114	Selected		Own	Storage	300	2029		Adams	
022	Backup		PPA	Storage	400	2029		Crowley	
132	Reviewed		PPA	Storage	300	2028		Pueblo	
061	Reviewed		PPA	Storage	200	2029		Pueblo	
024	Reviewed		PPA	Storage	400	2030		Crowley	
129	Reviewed		PPA	Storage	200	2029		Mesa	
093	Reviewed		Own	Storage	300	2030		Denver	
084	Reviewed		Own	Storage	60	2029		Kit Carson	
098	Reviewed		Own	Storage	58	2029		Boulder	
108	Reviewed		PPA	Storage	135	2030		Pueblo	

Bid 083 presents financial and compliance risk due to incomplete creditworthiness documentation (no credit score determined), lack of cultural/archeological reviews, and no stated plan for FEOC rule compliance. The [redacted] (Tri-State) Line Tap is considered unfavorable because its lower voltage offers limited transmission capacity, making it unsuitable for large-scale generation interconnections without significant upgrades. Additionally, tapping into a Tri-State-owned line can introduce coordination challenges and potential cost-sharing complexities, further reducing its attractiveness for portfolio selection.

Bid 117 faces unresolved environmental and permitting risks, including a levee intersecting the property, the need for an aquatic review, and FAA filing requirements. Additionally, it presupposes re-use of the [redacted] POI, and the Company believes analysis of the appropriate re-use of that transmission access should be considered in the JTS with the inclusion of computer modeling.

Bid 028 faces incomplete glint/glare and noise studies, interconnection on Segment 5 in El Paso County where permitting is not complete and Pathway construction has not started, recent 1041 permit denial in El Paso County indicating potential difficulty, and significant exposure to Denver Metro transmission constraints. In addition, [redacted] Line Tap is not favorable because it would require costly transmission upgrades and faces significant constructability and permitting challenges without providing proportional system benefits.

The remaining bids were simply below the cut line, but key due diligence findings are presented.

Bid 022 and Bid 024 introduce financial risk through capacity payments and an 18-year term that will likely create imputed debt and qualify as a finance lease. The project faces uncertain injection capability due to Denver Metro transmission constraints and requires

further studies and upgrades, making it operationally and economically risky. Additionally, the [redacted] Line Tap is not favorable because it requires extensive transmission upgrades and incurs high interconnection costs without delivering significant system reliability or operational benefits.

Bid 129 has financial risks through capacity payments and an 18-year term that will likely create imputed debt and qualify as a finance lease. Also, the bids levelized cost is $4/kW-mo higher than the bid selected for the portfolio, making it economically less competitive.

Bid 132 faces significant interconnection challenges due to Denver Metro constraints at [redacted], making its injection capability uncertain and operationally risky. The bid has financial risks through capacity payments and an 18-year term that will likely create imputed debt and qualify as a finance lease.

For Bid 084 the developer lacks critical financial strength and documentation, has not conducted cultural or archeological reviews, and failed to provide proof of site control or a clear procurement plan for major equipment. Additionally, the proposed [redacted] Tri-State line tap is disadvantageous because it introduces interconnection complexity and potential reliability risks without offering meaningful system benefits.

Bid 108 introduces financial risk through capacity payments and an 18-year term that will likely create imputed debt and qualify as a finance lease. Additionally, the project lacks critical environmental and site assessments, has no constraints map or species surveys,

7.5 THERMAL PROJECTS

The Company received thermal projects from different areas of the State, including in just transition communities and with a specific focus on the Pueblo area. Evaluation of the Pueblo thermal project bids, however, revealed significant current challenges. To be sure, these projects can support economic development and provide property tax benefits for a community impacted by coal plant retirements; nevertheless, at this time, the risks outweigh the benefits—particularly given the Company's resource adequacy position and concerns. Key issues included high capital costs and uncertainty around access to firm gas supply given the current pipeline infrastructure in the Pueblo area. For that reason, only one Pueblo-area thermal project advanced into more detailed evaluation.

Bid ID	Status	Project Name	Commercial Structure	Gen	Nameplate (MW)	First Summer Gen Year	LCC ($/kW-mo)	County	Point of Intersection
099	Selected	[redacted]	Own	Gas	200	2029	[redacted]	Weld	[redacted]
134	Reviewed		PPA	Gas	190	2030		Weld	
138	Reviewed		PPA	Gas	200	2029		LaPlata	
147	Reviewed		PPA	Gas	50	2029		Morgan	
145	Reviewed		PPA	Gas	50	2029		Morgan	
058	Reviewed		PPA	Gas	188	2030		Pueblo	
137	Reviewed		PPA	Gas	200	2029		LaPlata	

Bid 134 was reviewed extensively. The Company is aware that the Commission has repeatedly expressed a preference for diversity in thermal ownership and thus this bid initially appeared attractive. However, as due diligence proceeded, numerous fatal flaws were identified with this bid. First, the bidder requests open-ended walkaway rights throughout the development process, as well as full recovery of expenses incurred as of the walkaway point – essentially amounting to customer reimbursement of abandoned plant.

Second, the Company does not have completed bid forms from the bidder, though we have asked for them multiple times. In the bid forms, the bidder states "[Bidder] has a reservation agreement with [Turbine Supplier] at the portfolio level, and though a configuration is proposed, the technical details of the turbine configuration and its operating characteristics remain unknown." The bidder has also not provided a fuel description for the project, noting in one place in the bid documentation that the turbine would be dual fuel, but with no description or detail as to how much fuel will be stored onsite. All of the technical specification bid forms are essentially blank or missing, as the specific turbine selection and plant design has not been completed yet.

Third, bid transmission plans are vague and interconnection costs were not provided and are not known. The bid included $0 for interconnection costs in the bid forms, and stated: "[project] will be an additional Combustion Turbine(s) added to the operational [existing facility] site, and will utilize the existing interconnection infrastructure and equipment." However, in the bid narrative, the bidder provided one sentence for their Transmission Plan, stating "The Project will have a new Single 230 kV T line to the Xcel substation of the sufficient ampacity to handle the 3 units." When asked to provide more clarification on the plan for the new 230 kV line and the additional costs associated with its construction, the bidder replied that, "interconnection costs are unknown at this time and not included in the pricing provided…[Bidder] proposes passing these costs through to PSCo or providing a price adder for network upgrades once known." Therefore, the pricing the Company currently has in hand is not the final price the bidder would seek to charge for the project. This type of proposal does not align with the Company's firm pricing requirement for bids.

Fourth, additive transmission-related risk is significant, as the bid would likely require unknown system upgrades in the vicinity, including a possible new transformer at the

[redacted] substation. While technically feasible, these upgrades introduce uncertainty and potential delays.

In summary, the Company finds that the risks presented by Bid 134 outweigh the potential benefits of thermal generation-ownership diversity here. The Company has a clear and present need for firm, dispatchable capacity and is not opposed to the selection of PPA thermal projects. However, those projects must have a viable path to development, price certainty, and manageable customer risk. Bid 134 does not. Furthermore, when compared to Bid 099, Bid 134 is more costly and presents a potential COD approximately one year later thereby offering less system value.

Bid 138 has administrative and data integrity risk due to inconsistencies in nameplate capacity across forms, reliance on revised documentation late in the bid evaluation process, and potential delays in contract negotiations for the project. These issues could impact compliance and timeline for the NTP RFP.

Bid 147 and 145 face major financial and regulatory risks due to incomplete creditworthiness documentation, site leases and existing approvals appear to be tied to a solar/BESS project rather than the proposed thermal project, lack of environmental constraints mapping and cultural reviews, and significant permitting uncertainty. The permitting uncertainty is driven by complex air permit requirements, unresolved EPA and state regulatory applicability for linear generators, potential Acid Rain and NSPS compliance issues, and emissions modeling challenges associated with 201 distributed units—creating risks related to overlapping pollutant plumes, compliance with ambient air standards, and physical safety concerns such as fire hazards and emergency access in a high-density configuration. Timing for these activities is highly constrained given the NTP timeline and have a high potential to impact project viability if the project were to be included in the approved NTP portfolio and advance forward.

Bid 058 presents pricing compliance risk as toll prices appear based on ISO nameplate capacity (224 MW) rather than net tested capability (188 MW) per Model PPA requirements, and additional technical and environmental documentation—including water, cultural, biological surveys, and equipment layout—must be provided to validate feasibility and regulatory compliance. This documentation has not been provided at this time, and the pricing is well above Bid 099, which is included in the proposed NTP portfolio.

Bid 137 lacks critical compliance and readiness elements. The bid introduces financial risk through capacity payments and an 18-year term that likely creates imputed debt, and it fails to provide complete environmental and cultural assessments, site control documentation, and a clear procurement plan for major equipment. The bid's levelized

cost is nearly double that of the selected thermal project, making it significantly less competitive from an economic standpoint.

8. NEXT STEPS

The Company looks forward to the technical conference on December 18-19, 2025. At the technical conference, the Company will make available subject matter experts including Michael V. Pascucci, Director, Regulatory Policy; Jon T. Landrum, Director, Resource Planning; Anthony P. DeAugustino, Resource Planning Analyst; and John L. Bornhofen, Director, Purchased Power. All of these subject matter experts have appeared before the Commission in various, and in some cases numerous, proceedings. The Commission has scheduled a status conference on December 12, 2025, to discuss details of the technical conference.

Following response comments, which are due January 12, 2026, the Commission will deliberate and approve an NTP portfolio and a group of backup projects. A list of the Company's requested relief is provided in the Motion accompanying the filing of this NTP Report.

Upon approval of an NTP portfolio, the Company will move forward with contracting and project execution, including the negotiation of PPAs and build-transfer agreements with IPPs and engineering and supply contracts for self-build projects. For owned projects, the Company will bring forward CPCN applications at the appropriate time. If projects in the NTP portfolio prove unviable, the Company intends to utilize the same process approved in the 2021 ERP & CEP for the activation of backup bids. This would include, to the extent possible, activating backups that are like-for-like technology and ownership, and focused on lowest cost with considerations for deliverability and viability.

Looking ahead, the Company will fold the accredited capacity from the resources approved in the NTP portfolio into its capacity position for the JTS Base RFP. The Company will also consider the results of the NTP RFP when exploring ways to encourage bids in Just Transition communities in the JTS RFPs. The Company will also commence additional transmission studies based on the approved NTP portfolio and expected JTS resource additions.

Public Service is pleased to present this NTP Report following a successful NTP RFP process, and requests approval of the proposed NTP portfolio and backup bids as discussed above.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-94:
PSCo 2024 JTS, Volume 2 Technical Appendix

Colorado PUC E-Filings System

PUBLIC SERVICE COMPANY
OF COLORADO

2024 JUST TRANSITION SOLICITATION

Volume 2 Technical Appendix

CPUC Proceeding No. 24A-0442E

October 15, 2024

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2.0 CONTENTS OF THE 2024 JUST TRANSITION SOLICITATION

Public Service Company of Colorado ("Public Service," "PSCo," or the "Company") is filing its 2024 Just Transition Solicitation ("2024 JTS") pursuant to requirements set forth in the Updated Settlement Agreement ("USA") in Proceeding No. 21A-0141E, the 2021 Electric Resource Plan and Clean Energy Plan ("2021 ERP & CEP").[1] Paragraph 45 of the USA provides that to the extent any procedures or aspects of the 2024 JTS filing are not addressed by the USA, the application proceeding shall be treated as an Interim ERP under Rule 3603(a) and shall otherwise comply with applicable ERP Rules for the first and second phases of the process. Rule 3603(a) provides that the utility may file an interim plan (i.e., the 2024 JTS), pursuant to Rule 3604, which sets forth the required contents of the ERP.

Table 2.0-1 below, which reflects the current rules as of the date of the Company's filing, provides a matrix of the applicable rule requirements and indicates where the information can be found throughout Volume 2, and/or Volume 3 of the Company's Phase I 2024 JTS filing.

[1] Also referred to as the Pueblo Just Transition Plan or Just Transition Plan in the USA.

Table 2.0-1 ERP Rules Compliance Matrix

CPUC Rule	Required Information	Where
Rule 3604	**Contents of the Resource Plan**	
	The utility shall file a plan with the Commission that contains the information specified below. When required by the Commission, the utility shall provide work-papers to support the information contained in the plan. The plan shall include the following:	
Rule 3604	**Resource Acquisition Period and Planning Period**	
3604(a)	A statement of the utility-specified resource acquisition period and planning period. The utility shall consistently use the specified resource acquisition and planning periods throughout the entire resource plan and resource acquisition process. The utility shall include a detailed explanation as to why the specific period lengths were chosen in light of the assessment of the needs of the utility system.	Volume 2, Section 2.1
Rule 3604(b) & 3606	**Electric Demand and Energy Forecast**	
3604(b)	An annual electric demand and energy forecast developed pursuant to rule 3606.	Volume 2, Section 2.2
3606(a)	Forecast requirements. The utility shall prepare the following energy and demand forecasts for each year within the planning period.	
3606(a)(I)	Annual sales of energy and coincident summer and winter peak demand in total and disaggregated among Commission jurisdictional sales, FERC jurisdictional sales, and sales subject to the jurisdiction of other states.	
3606(a)(II)	Annual sales of energy and coincident summer and winter peak demand on a system wide basis for each major customer class.	
3606(a)(III)	Annual energy and capacity sales to other utilities; and capacity sales to other utilities at the time of coincident summer and winter peak demand.	
3606(a)(IV)	Annual intra-utility energy and capacity use at the time of coincident summer and winter peak demand.	
3606(a)(V)	Annual system losses and the allocation of such losses to the transmission and distribution components of the system. Coincident summer and winter peak system losses and the allocation of such losses to the transmission and distribution components of the systems.	
3606(a)(VI)	Typical day load patterns on a system-wide basis for each major customer class. This information shall be provided for peak-day, average-day, and representative off-peak days for each calendar month.	Volume 2, Section 2.3

CPUC Rule	Required Information	Where
3606(b)	Range of forecasts. The utility shall develop and justify a range of forecasts of coincident summer and winter peak demand and energy sales that its system may reasonably be required to serve during the planning period. The range shall include base case, high, and low forecast scenarios of coincident summer and winter peak demand and energy sales, based on alternative assumptions about the determinants of coincident summer and winter peak demand and energy of coincident summer and winter peak demand and energy sales during the planning period.	Volume 2, Section 2.2 (See also Omnibus Motion regarding requested partial rule waiver)
3606(c)	Required detail.	Volume 2, Section 2.2
3606(c)(I)	In preparing forecasts, the utility shall develop forecasts of energy sales and coincident summer and winter peak demand for each major customer class. The utility shall use end-use, econometric or other supportable methodology as the basis for these forecasts. If the utility determines not to use end-use analysis, it shall explain the reason for its determination as well as the rationale for its chosen alternative methodology.	
3606(c)(II)	The utility shall maintain, as confidential, information reflecting historical and forecasted demand and energy use for individual customers in those cases when an individual customer is responsible for the majority of the demand and energy used by a particular rate class. However, when necessary in the resource plan proceedings, such information may be disclosed to parties who intervene in accordance with the terms of non-disclosure agreements approved by the Commission and executed by the parties seeking disclosure.	
3606(d)	Historical data. The utility shall compare the annual forecast of coincident summer and winter peak demand and energy sales made by the utility to the actual coincident peak demand and energy sales experienced by the utility for the five years preceding the year in which the plan under consideration is filed. In addition, the utility shall compare the annual forecasts in its most recently filed resource plan to the annual forecasts in the current resource plan.	
3606(e)	Description and justification. The utility shall fully explain, justify, and document the data, assumptions, methodologies, models, determinants, and any other inputs upon which it relied to develop its coincident peak demand and energy sales forecasts pursuant to this rule, as well as the forecasts themselves.	
3606(f)	Format and graphical presentation of data. The utility shall include graphical presentation of the data to make the data more understandable to the public and shall make the data available to requesting parties in such electronic formats as the Commission shall reasonably require.	

CPUC Rule	Required Information	Where
Rule 3604(c) & 3607	**Evaluation of Existing Resources**	
3604(c)	An evaluation of existing resources developed pursuant to rule 3607.	Volume 2, Section 2.4
3607(a)	Existing generation resource assessment. The utility shall describe its existing resources, all utility-owned generating facilities for which the utility has obtained a Certificate of Public Convenience and Necessity (CPCN) from the Commission pursuant to § 40-5-101, C.R.S., at the time the plan is filed, and existing or future purchases from other utilities or non-utilities pursuant to agreements effective at the time the plan is filed. The description shall include, when applicable, the following:	
3607(a)(I)	Name(s) and location(s) of utility-owned generation facilities and energy storage systems.	
3607(a)(II)	Rated capacity and net dependable capacity of utility-owned generation facilities.	
3607(a)(III)	Fuel type, heat rates, annual capacity factors and availability factors projected for utility- owned generation facilities availability factors for utility-owned energy storage systems over the resource acquisition period.	
3607(a)(IV)	Estimated in-service dates for utility-owned generation facilities for which a CPCN has been granted but which are not in service at the time the plan under consideration is filed.	
3607(a)(V)	Estimated remaining useful lives of existing generation facilities and energy storage systems without significant new investment or maintenance expense.	
3607(a)(VI)	The amount of capacity and energy from generation facilities, energy storage systems, and demand-side resources purchased from utilities and non-utilities, the duration of such purchase contracts and a description of any contract provisions that allow for modification of the amount of capacity and energy from generation facilities or energy storage systems purchased pursuant to such contracts.	

CPUC Rule	Required Information	Where
3607(a)(VII)	The amount of capacity and energy provided from generation facilities and energy storage systems pursuant to wheeling or coordination agreements, the duration of such wheeling or coordination agreements, and a description of any contract provisions that allow for modification of the amount of capacity and energy from generation facilities or energy storage systems provided pursuant to such wheeling or coordination agreements.	Volume 2, Section 2.4
3607(a)(VIII)	The performance characteristics of utility-owned energy storage systems including but not limited to discharge rates and durations, charging rates, response time; and cycling losses and limitations.	
3607(a)(IX)	The physical and performance characteristics of energy storage systems purchased from utilities and non-utilities including but not limited to: storage technology; discharge rates and durations; charging rates; response time; and cycling losses and limitations.	
3607(a)(X)	The projected emissions, in terms of pounds per MWH and short-tons per year, of sulfur dioxide, nitrogen oxides, particulate matter, mercury and carbon dioxide for the resources identified under this paragraph 3607(a).	
3607(a)(XII)	The expected demand-side resources during the resource planning period from existing measures installed through utility-administered programs; and, from measures expected to be installed in the future through utility-administered programs in accordance with a Commission-approved plan.	
3607(b)	Utilities required to comply with these rules shall coordinate their electric resource plan filings such that the amount of electricity purchases and sales between utilities during the planning period is reflected uniformly in their respective plans. Disputes regarding the amount, timing, price, or other terms and conditions of such purchases and sales shall be fully explained in each utility's plan. If a utility files an interim plan as specified in rule 3603, the utility is not required to coordinate that filing with other utilities.	N/A 2024 JTS is considered an interim plan under Rule 3603(a)
Rule 3604(d) & 3608	**Transmission Resources**	
3604(d)	An evaluation of transmission resources pursuant to rule 3608.	Volume 2, Section 2.5
3608(a)	The utility shall report its existing transmission capabilities, and future needs during the planning period, for facilities of 115 kilovolts and above, including associated substations and terminal facilities. The utility shall generally identify the location and extent of transfer capability limitations on its transmission network that may affect the future siting of resources.	
3608(b)	With respect to future needs, the utility shall submit a description of all transmission lines and facilities appearing in its most recent report filed with the Commission pursuant to § 40-2-126, C.R.S., that, as identified in that report, could reasonably be placed into service during the resource acquisition period.	

CPUC Rule	Required Information	Where
3608(c)	For each transmission line or facility identified in paragraph (b), the utility shall include the following information detailing assumptions to be used for resource planning and bid evaluation purposes:	Volume 2, Section 2.5 (See also Omnibus Motion regarding requested partial rule waiver)
3608(c)(I)	Length and location.	
3608(c)(II)	Estimated in-service date.	
3608(c)(III)	Injection capacity.	
3608(c)(IV)	Estimated costs.	
3608(c)(V)	Terminal points.	
3608(c)(VI)	Voltage and megawatt rating.	
3608(d)	In order to equitably compare possible resource alternatives, the utility shall consider the transmission costs required by, or imposed on the system by, and the transmission benefits provided by a particular resource as part of the bid evaluation criteria.	
3608(e)	The resource plan shall describe and shall estimate the cost of all new transmission facilities associated with any specific resources proposed for acquisition other than through a competitive acquisition process.	N/A
Rule 3604(e) & 3609	**Planning Reserve Margin & Contingency Plans**	
3604(e)	An assessment of planning reserve margins and contingency plans for the acquisition of additional resources developed pursuant to rule 3609.	Volume 2, Section 2.6
3609(a)	The utility shall provide a description of, and justification for, the means by which it assesses the desired level of reliability on its system throughout the planning period (e.g., probabilistic or deterministic reliability indices).	
3609(b)	The utility shall develop and justify planning reserve margins for the resource acquisition period for the base case, high, and low forecast scenarios established under rule 3606, to include risks associated with: (1) the development of generation, (2) losses of generation capacity, (3) purchase of power, (4) losses of transmission capability, (5) risks due to known or reasonably expected changes in environmental regulatory requirements, and (6) other risks. The utility shall develop planning reserve margins for its system over the planning period beyond the resource acquisition period for the base case forecast scenario. The utility shall also quantify the recommended or required reliability performance criteria for reserve groups and power pools to which the utility is a party.	
3609(c)	Since actual circumstances may differ from the most likely estimate of future resource needs, the utility shall develop contingency plans for the resource acquisition period. As a part of its plan, the utility shall provide, under seal, a description of its proposed contingency plans for the acquisition of (1) additional resources if actual circumstances deviate from the most likely estimate of future resource needs developed pursuant to rule 3610, or (2) replacement resources in the event that resources are not developed in accordance with a Commission-approved plan under rule 3617. The utility will identify the estimated costs it will incur in developing the contingency plan for addressing the acquisition of these resources (*e.g.,* purchasing equipment options, establishing sites, engineering). The Commission will consider approval of contingency plans only after the utility receives bids, as described in subparagraph 3618(b)(II). The provisions of	

CPUC Rule	Required Information	Where
	paragraph 3617(d) shall not apply to the contingency plans unless explicitly ordered by the Commission.	
3604(f) & 3610	**Assessment of Need for Additional Resources**	
3604(f)	An assessment of the need for additional resources developed pursuant to rule 3610.	Volume 2, Section 2.8 & 2.9
3610(a)	By comparing the electric energy and demand forecasts developed pursuant to rule 3606 with the existing level of resources developed pursuant to rule 3607, and planning reserve margins developed pursuant to rule 3609, the utility shall assess the need to acquire additional resources during the resource acquisition period.	
3610(b)	In assessing its need to acquire additional resources, the utility shall also: (I) determine the additional eligible energy resources, if any, the utility will need to acquire to comply with the Commission's RES rules; (II) take into account the demand-side resources it must acquire to meet the energy savings and peak demand reduction goals established under §40-3.2-104 C.R.S. To that end, the Commission shall permit the utility to implement cost-effective demand-side resources to reduce the need for additional resources that would otherwise be met through a competitive acquisition process pursuant to rule 3611; (III) consider the benefits energy storage systems may provide to increase integration of intermittent resources, improve reliability, reduce the need for increased generation facilities to meet periods of peak demand; and avoid, reduce, or defer investments.	
3610(b)(I)	Determine the additional renewable energy resources (*e.g.,* retail distributed generation (DG), wholesale DG, non-DG) resources, if any, the utility will need to acquire to comply with the Commission's Renewable Energy Standard Rules.	
3610(b)(II)	Take into account the demand-side resources it must acquire to meet the energy savings and peak demand reduction goals established under § 40-3.2-104, C.R.S. To that end, the Commission shall permit the utility to implement cost-effective demand-side resources to reduce the need for additional resources that would otherwise be met through a competitive acquisition process pursuant to rule 3611.	
3610(b)(III)	Consider the benefits energy storage systems may provide to increase integration of intermittent resources, improve reliability; reduce the need for increased generation facilities to meet periods of peak demand; and avoid, reduce, or defer investments.	Volume 2, Section 2.8
3604(g) & 3611	**Resource Acquisition Plan**	
3604(g)	The utility's plan for acquiring these resources pursuant to rule 3611, including a description of the projected emissions, in terms of pounds per MWh and short tons per year, of sulfur dioxide, nitrogen oxides, particulate matter, mercury and carbon dioxide for any resources proposed to be owned by the utility and for any new generic resources included in the utility's modeling for its resource plan.	Volume 2, Section 2.4 & 2.13

CPUC Rule	Required Information	Where
3611(a)	It is the Commission's policy that a competitive acquisition process will normally be used to acquire new utility resources. The competitive bid process should afford all resources an opportunity to bid, and all new utility resources will be compared in order to determine a cost- effective resource plan (*i.e.,* an all-source solicitation).	Volume 2, Section 2.13
3611(b)	Notwithstanding the Commission's preference for all-source bidding for the acquisition of all new utility resources under these rules, the utility may propose in its filing under rule 3603, an alternative plan for acquiring the resources to meet the need identified in rule 3610. The utility shall specify the portion of the resource need that it intends to meet through an all-source competitive acquisition process and the portion that it intends to meet through an alternative method of resource acquisition.	
3611(c)	If the utility proposes that a portion of the resource need be met through an alternative method of resource acquisition, the utility shall identify the specific resource(s) that it wishes to acquire and the reason the specific resource(s) should not be acquired through an all-source competitive acquisition process. In addition, the utility shall provide a cost-benefit analysis to demonstrate the reason(s) why the public interest would be served by acquiring the specific resource(s) through an alternative method of resource acquisition.	
3611(d)	Although the utility may propose a method for acquiring new utility resources other than all-source competitive bidding, as a prerequisite, the utility shall nonetheless include in its plan filed under rule 3603 the necessary bid policies, RFPs, and model contracts necessary to satisfy the resource need identified under rule 3610 exclusively through all-source competitive bidding.	Volume 3
3611(e)	In the event that the utility proposes an alternative method of resource acquisition that involves the development of a new renewable energy resource or new supply-side resource that the utility shall own as a rate base investment, the utility shall file, simultaneously with its plan submitted under rule 3603, an application for a CPCN for such new resource. The Commission may consolidate, in accordance with the Commission's Rules of Practice and Procedure, the proceeding addressing that application for a CPCN with the resource planning proceeding. The utility shall provide a detailed estimate of the cost of the proposed facility to be constructed and information on alternatives studied, costs for those alternatives, and criteria used to rank or eliminate those alternatives.	N/A
3611(f)	The utility may participate in a competitive resource acquisition process by proposing the development of a new utility resource that the utility shall own as a rate base investment. The utility shall provide sufficient cost information in support of its proposal such that the Commission can reasonably compare the utility's proposal to alternative bids. In the event a utility proposes a rate base investment, the utility shall also propose how it intends to compare the utility rate based proposal(s) with non-utility bids. The Commission may also address the regulatory treatment of such costs with respect to future recovery.	Volume 3

CPUC Rule	Required Information	Where
3611(g)	Each utility shall propose a written bidding policy as part of its filing under rule 3603, including the assumptions, criteria, and models that will be used to solicit and evaluate bids in a fair and reasonable manner. The utility shall specify the competitive acquisition procedures that it intends to use to obtain resources under the utility's plan. The utility shall also propose, and other interested parties may provide input as part of the resource plan proceeding, criteria for evaluating the costs and benefits of resources such as the valuation of emissions and non-energy benefits.	Volume 2, Section 2.13
3611(h)	In the event that the utility proposes to acquire specific resources through an alternative method of resource acquisition that involves the development of a new renewable energy resource or new supply-side resource that the utility shall own as a rate base investment, the utility shall provide the Commission with the following best value employment metric information regarding each resource:	N/A
3611(h)(I)-(IV)	The availability of training programs, including training through apprenticeship programs registered with the United States Department of Labor, Office of Apprenticeship and Training;	Volume 2, Section 2.13
	The employment of Colorado workers as compared to importation of out-of-state workers;	
	Long-term career opportunities; and	
	Industry-standard wages, health care, and pension benefits.	
3604(h)	**Water Resources**	
3604(h)	The annual water consumption for each of the utility's existing generation resources, and the water intensity (in gallons per MWh) of the existing generating system as a whole, as well as the projected water consumption for any resources proposed to be owned by the utility and for any new generic resources included in the utility's modeling for its resource plan.	Volume 2, Section 2.12
3604(i)	**RFPs and Model Contracts**	
	The proposed RFP(s) the utility intends to use to solicit bids for energy and capacity resources to be acquired through a competitive acquisition process, including model contracts, pursuant to rule 3616.	Volume 3
3604(j)	**Confidential and Highly Confidential Information**	
	A list of the information related to the resource plan proceeding that the utility claims is confidential, and a list of the information related to the resource plan proceeding that the utility claims is highly confidential. The utility shall also list the information that it will provide to owners or developers of a potential resource under paragraphs 3613(a) and (b). The utility shall further explicitly list the protections it proposes for bid prices, other bid details, information concerning a new resource that the utility proposes to build and own as a rate base investment, other modeling inputs and assumptions, and the results of bid evaluation and selection. The protections sought by the utility for these items shall be specified in the motion(s) submitted under paragraph 3603(b). For good cause shown the utility may seek to protect additional information as confidential or highly confidential by filing the appropriate motion under rule 1100 of the Commission's Rules of Practice and Procedure in a timely manner.	Volume 2, Section 2.14

CPUC Rule	Required Information	Where
3604(k)	**Alternative Plans**	
	Descriptions of at least three alternate plans that can be used to represent the costs and benefits from increasing amounts of renewable energy resources, demand-side resources, or Section 123 resources as defined in paragraph 3602(q) potentially included in a cost-effective resource plan. One of the alternate plans shall represent a baseline case that describes the costs and benefits of the new utility resources required to meet the utility's needs during the planning period that minimize the net present value of revenue requirements and that complies with the Renewable Energy Standard, 4 CCR 723-3-3650 et seq., as well as with the demand-side resource requirements under § 40-3.2-104, C.R.S. The other alternate plans shall represent alternative combinations of resources that meet the same resource needs as the baseline case but that include proportionately more renewable energy resources, demand-side resources, or Section 123 resources. The utility shall propose a range of possible future scenarios and input sensitivities for the purpose of testing the robustness of the alternate plans under various parameters.	Volume 2, Section 2.10
3604(l)	**Additional Renewable Resources**	
	An assessment of the costs and benefits of the integration of intermittent renewable energy resources on the utility's system, including peer-reviewed studies, consistent with the amounts of renewable energy resources the utility proposes to acquire.	Volume 2, Section 2.10 & 2.11

CPUC Rule	Required Information	Where
3604(m)	**Energy Storage Systems Modeling Assumptions**	
	Modeling assumptions and analytical methodology proposed to assess the costs and benefits of energy storage systems including, but not limited to: integration of intermittent resources; improvement of reliability; reduction in the need for increased generation facilities to meet periods of peak demand; and avoidance, reduction, or deferral of investments.	Volume 2, Section 2.11
3604(n)	**Energy Storage Systems Smaller Than 30 MW**	
	The utility shall propose how energy storage systems smaller than 30 MW in size may be accommodated in the all-source competitive acquisition process.	Volume 2, Section 2.13
3616	**Request(s) for Proposals**	
3616(a)	Purpose of the request(s) for proposals. The proposed RFP(s) filed by the utility shall be designed to solicit competitive bids to acquire additional resources pursuant to rule 3611. To minimize bidder exceptions and to enhance bid comparability, the utility shall include in its proposed RFP(s) a model contract to match each type of resource need, including contracts for supply-side resources, energy storage systems, renewable energy resources, or Section 123 resources as required by the approved resource plan.	Volume 3
3616(b)	Contents of the request(s) for proposals. The proposed RFP(s) shall include the bid evaluation criteria the utility plans to use in ranking the bids received. The utility shall also include in its proposed RFP(s): details concerning its resource needs; reasonable estimates of transmission costs for resources located in different areas pursuant to rule 3608, including a detailed description of how the costs of future transmission will apply to bid resources; the extent and degree to which resources must be dispatchable, including the requirement, if any, that resources be able to operate under automatic dispatch control; any physical and performance requirements for energy storage systems or instructions for bidders to explain characteristics of energy storage systems, including but not limited to discharge rates and durations, charging rates, response time, and cycling losses and limitations; and methodologies or credit mechanisms to value energy storage services provided to the utility system; the utility's proposed model contract(s) for the acquisition of resources; proposed contract term lengths; discount rate; general planning assumptions; and, any other information necessary to implement a fair and reasonable bidding program.	
3616(c)	Employment metrics. The utility shall request from bidders the following information relating to best value employment metrics for each bid resource: (I) the availability of training programs, including training through apprenticeship programs registered with the United States Department of Labor, Office of Apprenticeship and Training; (II) the employment of Colorado workers as compared to importation of out-of-state workers; (III) long-term career opportunities; and (IV) industry-standard wages, health care, and pension benefits.	

CPUC Rule	Required Information	Where
3616(d)	When issuing its RFP, the utility shall provide potential bidders with the Commission's order or orders specifying the form of nondisclosure agreement necessary to obtain access to confidential and highly confidential modeling inputs and assumptions provided by the utility pursuant to paragraph 3613(b). The utility shall also provide potential bidders with an explanation of the process by which disputes regarding inputs and assumptions to computer-based modeling will be addressed by the Commission pursuant to paragraph 3613(b).	Volume 3
3616(e)	The utility shall require bidders to provide the contact name of the owner or developer designated to receive notice pursuant to paragraph 3613(a).	
3616(f)	The utility shall inform bidders that certain bid information submitted in response to the RFP will be made available to the public through the posting of certain bid information on the utility's website upon the completion of the competitive acquisition process pursuant to paragraph 3613(k).	

2.1 RESOURCE ACQUISITION AND PLANNING PERIOD

This section addresses the requirements of Rule 3604(a) requiring: (1) a statement of the utility-specified resource acquisition period and planning period to be used throughout the entire resource plan and resource acquisition process, and (2) an explanation as to why the specific period lengths were chosen considering the assessment of the needs of the utility system.

Resource Acquisition Period

Rule 3602(n) defines "resource acquisition period" (or "RAP") as "the first six to ten years of the planning period, in which the utility acquires specific resources to meet projected electric system demand and energy requirements. The RAP begins from the date the utility files its plan with the Commission."

In past ERPs, the Company has typically proposed a RAP and discussed the reasons and circumstances that inform a particular RAP timeframe as part of its Phase I filing. For this 2024 JTS, the RAP is established through the USA approved by the Commission in Proceeding No. 21A-0141E. Specifically, paragraph 15 of the USA provides that all 2029 and 2030 resource needs identified will be filled through the JTS, which will utilize a RAP through end of year 2031.[2] Thus, the RAP for the 2024 JTS will be 2024-2031.

While the RAP begins in 2024 when the Company is filing this 2024 JTS, considering the typical regulatory timeframe for Phase I and Phase II and assuming an 18-month timeframe to construct and or contract new resources following a Phase II decision, it is unlikely that resources will be able to come online before 2028.

Planning Period

Rule 3602(k) defines "planning period" as "the future period for which a utility develops its plan, and the period, over which net present value of revenue requirements for resources are calculated... [t]he planning period is twenty to forty years and begins from the date the utility files its plan with the Commission."

Public Service proposes a planning period from the 2024 JTS filing date extending through 2050, or approximately 26 years, which represents the target date to provide customers with energy generated from 100 percent clean energy resources consistent with Colorado State policy. To effectuate a planning period through 2050, the EnCompass planning model is run through 2050. The Company proposes to run the model only through 2050 for several reasons, including: (1) adding years to the simulation beyond 2050 increases model complexity and run times; (2) most key inputs are not forecasted beyond 2050; and (3) the target imposed by Senate Bill 19-236 to meet zero tons of carbon emissions by 2050 creates a relatively subjective portfolio in the latter years when using only generic resources based on today's known technologies.

[2] Decision No. C22-0459, at ¶97.

2.2 ELECTRIC ENERGY AND DEMAND FORECASTS

Introduction

In this Section, the Company sets forth detailed electric energy and demand forecast information required by Rule 3604(b) and Rule 3606. The energy and demand forecasts represent the Company's expectations for native load, which does not include reductions due to distributed generation, as distributed generation is considered a resource.

Projections of future energy and peak demand are fundamental inputs into Public Service's resource need assessment. Public Service prepared two forecasts for the 2024 JTS: (1) a Base forecast (or "Base Case"), and (2) a Low forecast. These forecasts are discussed in more detail later in this Section.

Figures 2.2-1 and 2.2-2 below show the Base and Low forecasts of native load peak demand and energy graphically. Tables 2.2-1 and 2.2-2 further below show the data supporting Figures 2.2-1 and 2.2-2, respectively. The black line on the figures and grey area on the tables indicate the end of the RAP in 2031.

Public Service projects the Base forecast native load peak demand (retail and firm wholesale requirements customers) to grow at a compounded annual rate of 4.0% or an average of 327 megawatts ("MW") per year through the RAP. This is faster than the 0.7% growth rate over the last five years. Public Service's Low forecast for peak demand increases at a compounded growth rate of 1.1% per year over the same period.

Public Service projects Base annual energy to increase at a compounded annual growth rate of 7.0% or an average of 3,002 gigawatt hours ("GWh") per year through the RAP. Public Service's Low forecast of annual energy grows at a compounded rate of 2.8% per year over the same period.

The Base peak demand forecast assumes economic growth based on projections from IHS Markit and average summer peak weather conditions. The Base forecast also assumes the rate of electric vehicle ("EV") adoption increases over time and includes electrification impacts based on the Amended Preferred Portfolio in the Clean Heat Plan (Proceeding No. 23A-0392G). The Base forecast also includes the addition of new, large loads to the system and oil and gas electrification. The Low forecast includes slower EV adoption, less oil and gas electrification, and a conservative approach to including new, large loads.

Table 2.2-3 provides a comparison of the peak demand forecast discussed in this section with the peak demands shown in the Loads and Resources ("L&R") table. The same load forecast was used in the modeling and L&R that is described here, but the demands in this section represent Native load at the time of the Obligation peak while the demands in the L&R table represent Native load peaks at the time of the Native peak. The peaks in the L&R also include the expected generation from the Bighorn solar facility since Bighorn is counted as a resource instead of a load modifier, while that is excluded from the peak demands addressed in this section.

Figure 2.2-1 Native Load Peak Demand Forecasts

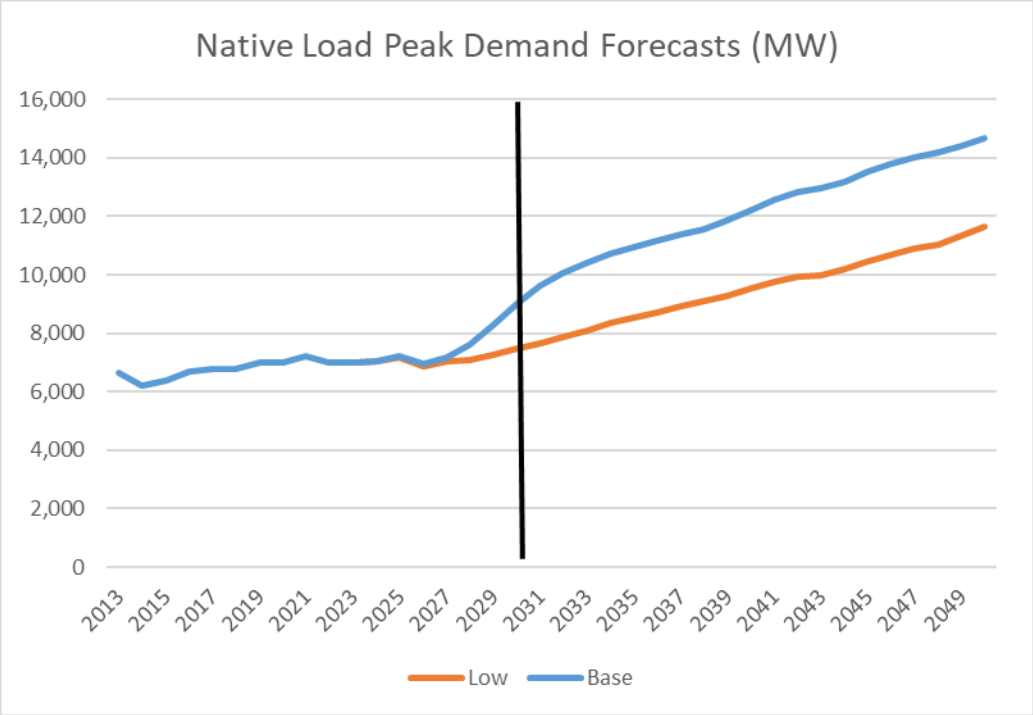


Figure 2.2 2 Native Load Energy Forecasts

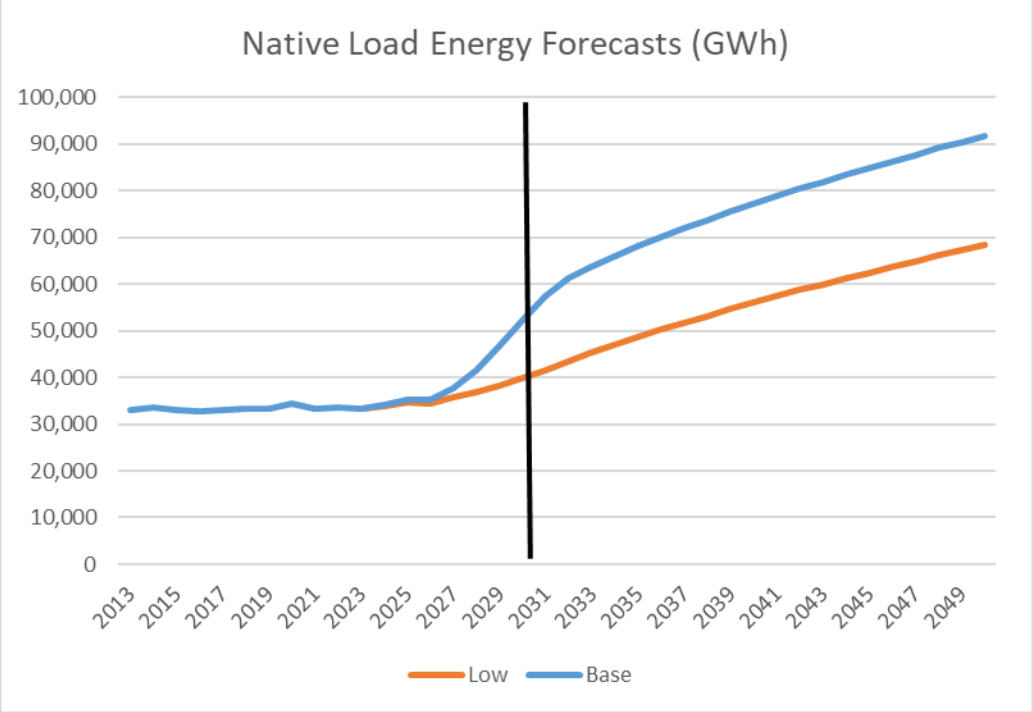


Table 2.2-1 Actual and Forecasted Native Load Peak Demand

	MW		Annual Growth		Compound Growth to/from 2023	
	Base	Low	Base	Low	Base	Low
2013	6,643				0.5%	
2014	6,216		-6.4%		1.3%	
2015	6,359		2.3%		1.2%	
2016	6,670		4.9%		0.7%	
2017	6,767		1.5%		0.6%	
2018	6,758		-0.1%		0.7%	
2019	6,992		3.5%		0.1%	
2020	7,002		0.1%		0.0%	
2021	7,195		2.8%		-1.3%	
2022	6,991		-2.8%		0.2%	
2023	7,008	7,008	0.2%		0.0%	
2024	7,060	7,041	0.7%	0.7%	0.7%	0.5%
2025	7,215	7,173	2.2%	1.9%	1.5%	1.2%
2026	6,945	6,869	-3.7%	-4.2%	-0.3%	-0.7%
2027	7,189	7,021	3.5%	2.2%	0.6%	0.0%
2028	7,597	7,077	5.7%	0.8%	1.6%	0.2%
2029	8,268	7,252	8.8%	2.5%	2.8%	0.6%
2030	8,992	7,479	8.8%	3.1%	3.6%	0.9%
2031	9,628	7,633	7.1%	2.1%	4.0%	1.1%
2032	10,074	7,867	4.6%	3.1%	4.1%	1.3%
2033	10,416	8,111	3.4%	3.1%	4.0%	1.5%
2034	10,708	8,341	2.8%	2.8%	3.9%	1.6%
2035	10,950	8,538	2.3%	2.4%	3.8%	1.7%
2036	11,168	8,716	2.0%	2.1%	3.6%	1.7%
2037	11,400	8,916	2.1%	2.3%	3.5%	1.7%
2038	11,549	9,082	1.3%	1.9%	3.4%	1.7%
2039	11,846	9,293	2.6%	2.3%	3.3%	1.8%
2040	12,208	9,521	3.1%	2.4%	3.3%	1.8%
2041	12,544	9,760	2.8%	2.5%	3.3%	1.9%
2042	12,828	9,954	2.3%	2.0%	3.2%	1.9%
2043	12,955	9,978	1.0%	0.2%	3.1%	1.8%
2044	13,194	10,178	1.9%	2.0%	3.1%	1.8%
2045	13,515	10,461	2.4%	2.8%	3.0%	1.8%
2046	13,775	10,681	1.9%	2.1%	3.0%	1.8%
2047	14,032	10,896	1.9%	2.0%	2.9%	1.9%
2048	14,187	11,015	1.1%	1.1%	2.9%	1.8%
2049	14,394	11,337	1.5%	2.9%	2.8%	1.9%
2050	14,686	11,659	2.0%	2.8%	2.8%	1.9%

Table 2.2-2 Actual and Forecasted Annual Native Load Energy

	GWh		Annual Growth		Compound Growth to/from 2023	
	Base	Low	Base	Low	Base	Low
2013	33,143				0.0%	
2014	33,666		1.6%		-0.1%	
2015	33,139		-1.6%		0.1%	
2016	32,856		-0.9%		0.2%	
2017	32,929		0.2%		0.2%	
2018	33,363		1.3%		0.0%	
2019	33,282		-0.2%		0.0%	
2020	34,319		3.1%		-1.0%	
2021	33,418		-2.6%		-0.2%	
2022	33,673		0.8%		-1.1%	
2023	33,298	33,298	-1.1%		0.0%	
2024	34,003	33,857	2.1%	1.7%	2.1%	1.7%
2025	35,124	34,736	3.3%	2.6%	2.7%	2.1%
2026	35,216	34,466	0.3%	-0.8%	1.9%	1.2%
2027	37,749	35,677	7.2%	3.5%	3.2%	1.7%
2028	41,498	36,730	9.9%	3.0%	4.5%	2.0%
2029	46,620	38,127	12.3%	3.8%	5.8%	2.3%
2030	52,315	39,914	12.2%	4.7%	6.7%	2.6%
2031	57,312	41,644	9.6%	4.3%	7.0%	2.8%
2032	61,161	43,522	6.7%	4.5%	7.0%	3.0%
2033	63,740	45,243	4.2%	4.0%	6.7%	3.1%
2034	65,993	46,945	3.5%	3.8%	6.4%	3.2%
2035	68,050	48,584	3.1%	3.5%	6.1%	3.2%
2036	70,165	50,226	3.1%	3.4%	5.9%	3.2%
2037	71,925	51,681	2.5%	2.9%	5.7%	3.2%
2038	73,695	53,155	2.5%	2.9%	5.4%	3.2%
2039	75,438	54,615	2.4%	2.7%	5.2%	3.1%
2040	77,282	56,111	2.4%	2.7%	5.1%	3.1%
2041	78,802	57,402	2.0%	2.3%	4.9%	3.1%
2042	80,412	58,729	2.0%	2.3%	4.7%	3.0%
2043	81,720	59,792	1.6%	1.8%	4.6%	3.0%
2044	83,417	61,218	2.1%	2.4%	4.5%	2.9%
2045	84,741	62,411	1.6%	1.9%	4.3%	2.9%
2046	86,164	63,642	1.7%	2.0%	4.2%	2.9%
2047	87,566	64,853	1.6%	1.9%	4.1%	2.8%
2048	89,112	66,139	1.8%	2.0%	4.0%	2.8%
2049	90,276	67,162	1.3%	1.5%	3.9%	2.7%
2050	91,640	68,308	1.5%	1.7%	3.8%	2.7%

Table 2.2-3 Comparison of Peak Demand Forecasts

	Peak Fcst (MW)	Peak - L&R (MW)
2024	7,060	7,185
2025	7,215	7,327
2026	6,945	7,039
2027	7,189	7,348
2028	7,597	7,732
2029	8,268	8,437
2030	8,992	9,123
2031	9,628	9,720
2032	10,074	10,141
2033	10,416	10,464
2034	10,708	10,736
2035	10,950	10,963
2036	11,168	11,173
2037	11,400	11,405
2038	11,549	11,596
2039	11,846	11,846
2040	12,208	12,208
2041	12,544	12,544
2042	12,828	12,828
2043	12,955	12,955
2044	13,194	13,194
2045	13,515	13,515
2046	13,775	13,775
2047	14,032	14,032
2048	14,187	14,187
2049	14,394	14,394
2050	14,686	14,686

Economic Conditions and Outlook

Public Service used data from the IHS Markit January 2024 economic outlook to develop its forecasts. Specifically, the Company tracked key indicators for the metropolitan areas located within its service territory. These key indicators include population, real personal income, non-farm employment, and gross metropolitan product ("GMP").

The economy of the Company's service territory showed growth from 2018-2023, despite the slowdown in 2020 due to the COVID-19 pandemic. GMP grew, on average, 2.8% during that period. Job growth averaged 1.2% and real personal income growth averaged 2.6% during that period. Population growth slowed from 2021-2023, averaging 0.6% for those three years.

IHS Markit's outlook expects steady employment growth of 0.8% through the RAP and 0.7% through the planning period. Population growth is expected to return to more historic levels of 1.0% through the RAP before slowing beyond 2031. GMP growth is expected to slow and real personal income growth is expected to be in line with historical trends.

Table 2.2-4 summarizes the economic history and outlook for the key economic drivers.

Table 2.2-4 Growth Rates for Key Economic Drivers

	Average Annual Growth			
	Employment	Population	GMP	Real Pers Inc
2018-2023	1.2%	0.8%	2.8%	2.6%
2023-2031	0.8%	1.0%	1.9%	2.5%
2023-2050	0.7%	0.8%	2.0%	2.5%

Peak Demand Trends and Forecast

Table 2.2-5 shows the actual and forecasted retail and wholesale peak demands.

Table 2.2-5 Peak Demand Forecast – Base Case, Retail, and Wholesale

	MW			Annual Growth			Compound Growth to/from 2023		
	Retail	Wholesale	Total	Retail	Wholesale	Total	Retail	Wholesale	Total
2013	5,875	768	6,643				1.0%	-3.8%	0.5%
2014	5,748	468	6,216	-2.2%	-39.0%	-6.4%	1.4%	1.1%	1.3%
2015	5,729	630	6,359	-0.3%	34.5%	2.3%	1.6%	-2.4%	1.2%
2016	6,068	602	6,670	5.9%	-4.4%	4.9%	1.0%	-2.1%	0.7%
2017	6,238	530	6,767	2.8%	-12.0%	1.5%	0.7%	-0.3%	0.6%
2018	6,191	567	6,758	-0.8%	7.1%	-0.1%	0.9%	-1.8%	0.7%
2019	6,192	801	6,992	0.0%	41.1%	3.5%	1.2%	-10.3%	0.1%
2020	6,176	826	7,002	-0.3%	3.2%	0.1%	1.7%	-14.3%	0.0%
2021	6,636	559	7,195	7.4%	-32.3%	2.8%	-1.1%	-3.7%	-1.3%
2022	6,452	540	6,991	-2.8%	-3.5%	-2.8%	0.6%	-3.8%	0.2%
2023	6,489	519	7,008	0.6%	-3.8%	0.2%	0.0%	0.0%	0.0%
2024	6,499	561	7,060	0.2%	8.0%	0.7%	0.2%	8.0%	0.7%
2025	6,640	575	7,215	2.2%	2.5%	2.2%	1.2%	5.2%	1.5%
2026	6,789	156	6,945	2.3%	-72.9%	-3.7%	1.5%	-33.1%	-0.3%
2027	7,036	153	7,189	3.6%	-1.8%	3.5%	2.0%	-26.3%	0.6%
2028	7,565	32	7,597	7.5%	-79.2%	5.7%	3.1%	-42.8%	1.6%
2029	8,238	30	8,268	8.9%	-4.8%	8.8%	4.1%	-37.7%	2.8%
2030	8,959	33	8,992	8.8%	9.1%	8.8%	4.7%	-32.5%	3.6%
2031	9,593	35	9,628	7.1%	6.0%	7.1%	5.0%	-28.6%	4.0%
2032	10,040	35	10,074	4.7%	-1.1%	4.6%	5.0%	-26.0%	4.1%
2033	10,380	36	10,416	3.4%	3.9%	3.4%	4.8%	-23.4%	4.0%
2034	10,672	36	10,708	2.8%	0.0%	2.8%	4.6%	-21.5%	3.9%
2035	10,914	36	10,950	2.3%	-0.1%	2.3%	4.4%	-19.9%	3.8%
2036	11,132	36	11,168	2.0%	0.1%	2.0%	4.2%	-18.6%	3.6%
2037	11,364	36	11,400	2.1%	0.0%	2.1%	4.1%	-17.4%	3.5%
2038	11,515	35	11,549	1.3%	-4.0%	1.3%	3.9%	-16.5%	3.4%
2039	11,731	115	11,846	1.9%	232.6%	2.6%	3.8%	-9.0%	3.3%
2040	12,089	119	12,208	3.1%	3.3%	3.1%	3.7%	-8.3%	3.3%
2041	12,426	118	12,544	2.8%	-0.7%	2.8%	3.7%	-7.9%	3.3%
2042	12,711	117	12,828	2.3%	-0.8%	2.3%	3.6%	-7.5%	3.2%
2043	12,955	-	12,955	1.9%		1.0%	3.5%		3.1%
2044	13,194	-	13,194	1.9%		1.9%	3.4%		3.1%
2045	13,515	-	13,515	2.4%		2.4%	3.4%		3.0%
2046	13,775	-	13,775	1.9%		1.9%	3.3%		3.0%
2047	14,032	-	14,032	1.9%		1.9%	3.3%		2.9%
2048	14,187	-	14,187	1.1%		1.1%	3.2%		2.9%
2049	14,394	-	14,394	1.5%		1.5%	3.1%		2.8%
2050	14,686	-	14,686	2.0%		2.0%	3.1%		2.8%

Native load peak demand in Public Service's service territory has advanced 250 MW during the past five years, driven by retail growth of 299 MW. Total peak demand has averaged 0.7% growth and retail peak demand has increased an average of 0.9% over that time. Wholesale demand has decreased 48 MW over the same time period.

Peak demand is expected to increase through the RAP, as the growth in retail load more than offsets the declines in wholesale. In total, load is expected to grow on average 4.0% through 2031, with retail growing at an average rate of 5.0%.

Energy Trends and Forecast

Table 2.2-6 shows the actual and forecasted retail and wholesale energy amounts (or native energy).

The large increases in wholesale energy in 2020 and 2022 are due to Comanche 3 being offline, which results in Public Service's contractual requirement to serve additional load for the partners.

Native energy has been about flat from 2018-2023. Small declines in retail load have been offset by slight gains in wholesale load.

Native energy is expected to increase through the RAP at an average rate of 7.0% per year. Retail growth of 7.9% is offsetting the declines in wholesale energy due to the expiration of contracts. Retail growth is expected to increase due to the adoption of EVs, beneficial electrification ("BE"), and new, large loads as discussed in later sections.

Table 2.2-6 Native Energy Forecast – Base Case, Retail, and Wholesale

	GWh			Annual Growth			Compound Growth to/from 2023		
	Retail	Wholesale	Total	Retail	Wholesale	Total	Retail	Wholesale	Total
2013	30,588	2,555	33,143				0.2%	-1.7%	0.0%
2014	31,008	2,658	33,666	1.4%	4.1%	1.6%	0.0%	-2.3%	-0.1%
2015	30,909	2,229	33,139	-0.3%	-16.1%	-1.6%	0.1%	-0.4%	0.1%
2016	30,884	1,973	32,856	-0.1%	-11.5%	-0.9%	0.1%	1.2%	0.2%
2017	30,808	2,122	32,929	-0.2%	7.6%	0.2%	0.2%	0.2%	0.2%
2018	31,250	2,113	33,363	1.4%	-0.4%	1.3%	-0.1%	0.4%	0.0%
2019	31,193	2,089	33,282	-0.2%	-1.2%	-0.2%	0.0%	0.7%	0.0%
2020	30,810	3,509	34,319	-1.2%	68.0%	3.1%	0.4%	-15.1%	-1.0%
2021	31,196	2,222	33,418	1.3%	-36.7%	-2.6%	-0.1%	-1.6%	-0.2%
2022	30,901	2,773	33,673	-0.9%	24.8%	0.8%	0.8%	-22.4%	-1.1%
2023	31,147	2,151	33,298	0.8%	-22.4%	-1.1%	0.0%	0.0%	0.0%
2024	31,594	2,409	34,003	1.4%	12.0%	2.1%	1.4%	12.0%	2.1%
2025	32,810	2,314	35,124	3.8%	-3.9%	3.3%	2.6%	3.7%	2.7%
2026	34,060	1,156	35,216	3.8%	-50.1%	0.3%	3.0%	-18.7%	1.9%
2027	36,575	1,174	37,749	7.4%	1.6%	7.2%	4.1%	-14.0%	3.2%
2028	40,831	667	41,498	11.6%	-43.2%	9.9%	5.6%	-20.9%	4.5%
2029	46,344	276	46,620	13.5%	-58.6%	12.3%	6.8%	-29.0%	5.8%
2030	52,036	278	52,315	12.3%	0.8%	12.2%	7.6%	-25.3%	6.7%
2031	57,044	268	57,312	9.6%	-3.8%	9.6%	7.9%	-22.9%	7.0%
2032	60,896	265	61,161	6.8%	-1.1%	6.7%	7.7%	-20.8%	7.0%
2033	63,466	274	63,740	4.2%	3.5%	4.2%	7.4%	-18.6%	6.7%
2034	65,719	274	65,993	3.6%	0.0%	3.5%	7.0%	-17.1%	6.4%
2035	67,776	274	68,050	3.1%	0.0%	3.1%	6.7%	-15.8%	6.1%
2036	69,891	274	70,165	3.1%	0.0%	3.1%	6.4%	-14.7%	5.9%
2037	71,650	274	71,925	2.5%	0.0%	2.5%	6.1%	-13.7%	5.7%
2038	73,421	274	73,695	2.5%	0.0%	2.5%	5.9%	-12.8%	5.4%
2039	75,163	274	75,438	2.4%	0.0%	2.4%	5.7%	-12.1%	5.2%
2040	77,008	274	77,282	2.5%	0.0%	2.4%	5.5%	-11.4%	5.1%
2041	78,528	274	78,802	2.0%	0.0%	2.0%	5.3%	-10.8%	4.9%
2042	80,138	274	80,412	2.1%	0.0%	2.0%	5.1%	-10.3%	4.7%
2043	81,720	-	81,720	2.0%		1.6%	4.9%		4.6%
2044	83,417	-	83,417	2.1%		2.1%	4.8%		4.5%
2045	84,741	-	84,741	1.6%		1.6%	4.7%		4.3%
2046	86,164	-	86,164	1.7%		1.7%	4.5%		4.2%
2047	87,566	-	87,566	1.6%		1.6%	4.4%		4.1%
2048	89,112	-	89,112	1.8%		1.8%	4.3%		4.0%
2049	90,276	-	90,276	1.3%		1.3%	4.2%		3.9%
2050	91,640	-	91,640	1.5%		1.5%	4.1%		3.8%

Electric Vehicles

The forecast for electric vehicle adoption is based on modeling as described below. The Base forecast uses the Company's "high" case for EV adoption and the Low forecast uses the "mid" case.

Light Duty Vehicles ("LDV")

The Base Case and Low scenario EV forecasts estimate EV adoption using two modeling techniques: (1) Bass diffusion modeling, and (2) economic modeling. After establishing forecasts through both methods, we average the results to estimate EV adoption.

- *Bass Diffusion Modeling.* Bass diffusion models are used to describe technology adoptions patterns in an existing market through an "S" shaped diffusion characteristic. The Bass diffusion model approach is calibrated using state-specific historical EV sales.

- *Economic Modeling.* Economic models use simple payback analysis to estimate potential adoption, incorporating factors such as battery prices, tax incentives, fuel savings, and others.

Additionally, we have incorporated into both the Bass diffusion and economic models a factor for the percentage of vehicles in urban and rural areas. Presently, higher adoption is occurring in urban areas with the rural areas anticipated to ramp up slowly. The estimates are also sensitive to several exogenous variables because battery market dynamics are a significant factor in the cost of EVs. These variables may include policy, technology, manufacturing supply chain, and geopolitical factors, among others.

Medium and Heavy-Duty Vehicles

The Company utilizes a medium-duty vehicle ("MDV") and heavy-duty vehicle ("HDV") forecast that was produced by a third-party consultant (Guidehouse). The forecast provided was specific to Public Service's service territory in Colorado.

EV Load Shapes

The Base Case and Low scenarios utilize one managed and one unmanaged charging profile through 2027. The share of managed charging begins at a program participation rate of 5% and increases linearly to 70% to reflect increased program participation, responsiveness to time-of-use rates, and unspecified future managed charging programs. The unmanaged charging profiles for LDV were developed using data from several external sources, while the MDV/HDV profiles were produced by a third-party consultant (Navigant, now Guidehouse). The managed charging profile for LDV was largely developed using internal data from Xcel customers participating in the managed charging program.

Beginning in 2028, all vehicle classes begin to split new managed load additions between multiple tranches. Each tranche represents a distinct charging profile defined by the base managed charging profile shifted a set number of hours later. For MDV/HDV, there is only one additional tranche shifted backward by three hours. For LDV, there are four additional tranches, shifted backward by three, six, 10, and 13 hours. Sales are shifted toward these additional tranches until sales are roughly equivalent with the original managed charging profile, at which point additions are split evenly across all tranches.

The tranche approach is intended to loosely reflect the effects of increased use of dynamic charging over time, combined with the need to distribute EV loads to avoid defining peak hours. While true dynamic charging profiles will likely differ from the result modeled in this approach, it should more closely resemble its flatter net profile. The choice of tranches is intended to capture some of the diversity in customer driving profiles, as well as the potential to emphasize charging during high solar production hours.

Table 2.2-7 below shows forecasted EV adoption included in the Base and Low forecasts.

Table 2.2-7 Number of EVs by Scenario

	Mid				High			
	LDV	MDV	HDV	Total	LDV	MDV	HDV	Total
2024	112,614	634	384	113,632	138,373	456	1,586	140,415
2025	144,900	908	534	146,342	187,191	792	2,328	190,311
2026	189,208	1,211	702	191,120	249,506	1,218	3,156	253,880
2027	249,616	1,542	886	252,045	329,646	1,746	4,049	335,441
2028	331,216	1,901	1,087	334,204	432,919	2,383	4,996	440,299
2029	440,018	2,284	1,303	443,605	557,252	3,137	5,992	566,381
2030	561,768	2,690	1,532	565,991	684,167	4,012	7,023	695,201
2031	692,558	3,119	1,776	697,453	814,239	5,012	8,086	827,337
2032	835,887	3,765	2,143	841,795	947,954	5,835	9,414	963,203
2033	943,804	4,251	2,420	950,475	1,073,091	6,606	10,657	1,090,353
2034	1,054,497	4,750	2,704	1,061,950	1,200,696	7,391	11,924	1,220,011
2035	1,168,048	5,261	2,995	1,176,304	1,331,671	8,197	13,224	1,353,093
2036	1,283,000	5,779	3,290	1,292,069	1,464,313	9,014	14,542	1,487,868
2037	1,399,445	6,303	3,588	1,409,336	1,598,697	9,841	15,876	1,624,414
2038	1,517,605	6,836	3,891	1,528,332	1,735,053	10,680	17,230	1,762,964
2039	1,637,541	7,376	4,199	1,649,116	1,873,413	11,532	18,604	1,903,550
2040	1,761,103	7,932	4,516	1,773,551	2,015,585	12,407	20,016	2,048,008
2041	1,882,579	8,480	4,827	1,895,886	2,155,765	13,270	21,408	2,190,443
2042	2,001,434	9,015	5,132	2,015,580	2,293,356	14,117	22,775	2,330,248
2043	2,116,819	9,535	5,428	2,131,782	2,417,802	14,883	24,010	2,456,696
2044	2,242,458	10,101	5,750	2,258,308	2,548,451	15,687	25,308	2,589,446
2045	2,367,933	10,666	6,072	2,384,670	2,678,825	16,490	26,603	2,721,918
2046	2,492,621	11,227	6,391	2,510,239	2,808,653	17,289	27,892	2,853,834
2047	2,615,660	11,782	6,707	2,634,149	2,937,577	18,083	29,172	2,984,832
2048	2,735,951	12,323	7,015	2,755,290	3,065,215	18,868	30,440	3,114,523
2049	2,851,981	12,846	7,313	2,872,140	3,191,051	19,643	31,689	3,242,384
2050	2,961,533	13,340	7,594	2,982,466	3,314,215	20,401	32,912	3,367,529

Beneficial Electrification Forecast

The Company's Beneficial Electrification forecast was developed based on the programs related to the DSM Strategic Issues filing and assumptions around market electrification through 2026. Beyond 2026, the impacts of BE are assumed to ramp to meet the emissions goals of the Amended Preferred Portfolio in the Company's Rebuttal Testimony in its Clean Heat Plan proceeding by 2030. Impacts are then extrapolated to the end of the forecast period. At the time this forecast was developed, the Clean Heat proceeding and order had not been finalized. The same assumptions for beneficial electrification are used in both the Base and Low forecasts. Table 2.2.8 shows the appliance saturations assumed in the forecasts.

Table 2.2-8 Appliance Conversions by Type

	All Scenarios				
	Residential Hybrid Heat	Residential All-Electric Heat	Residential Water Heat *	Commercial Space Heat	Commercial Water Heat
2024	3,064	865	1,194	20	20
2025	10,916	3,056	3,986	60	60
2026	25,989	7,253	9,289	202	202
2027	46,700	29,712	122,278	537	537
2028	67,410	52,172	235,266	947	947
2029	88,121	74,631	348,255	1,433	1,433
2030	108,832	97,091	461,244	1,972	1,972
2031	135,331	120,958	562,592	2,457	2,457
2032	162,238	145,175	662,419	2,894	2,894
2033	189,225	169,457	760,366	3,287	3,287
2034	216,166	193,693	856,397	3,641	3,641
2035	243,015	217,843	950,567	3,959	3,959
2036	269,734	241,874	1,042,884	4,246	4,246
2037	296,318	265,780	1,133,512	4,504	4,504
2038	322,780	289,576	1,223,775	4,736	4,736
2039	349,106	313,249	1,313,643	4,945	4,945
2040	375,294	336,796	1,403,116	5,133	5,133
2041	401,362	360,234	1,492,249	5,302	5,302
2042	427,327	383,578	1,581,088	5,454	5,454
2043	453,200	406,837	1,676,710	5,591	5,591
2044	479,011	430,041	1,764,613	5,714	5,714
2045	504,761	453,189	1,836,961	5,826	5,826
2046	530,420	476,253	1,870,835	5,925	5,925
2047	555,947	499,199	1,904,341	6,015	6,015
2048	581,415	522,090	1,937,679	6,096	6,096
2049	606,822	544,925	1,970,845	6,169	6,169
2050	637,415	572,418	2,008,576	6,235	6,235

* Includes water heater conversion for all-electric heating customers

Forecast for Large Load Additions

The Base Case forecast includes two assumptions for additional data center and manufacturing loads. First, the Base forecast includes all loads that are assessed as having an 80 percent or greater probability of connection. Second, the Base forecast includes half of the probabilistic weighted load for requests that have a 50 to 79 percent probability of connection. For example, for a project with a 50 percent probability of connection, the Base forecast will include 25 percent of the project's projected load. Similarly, 35 percent of the load will be included if the project has a 70 percent probability of connection. For each type of load, a pace of load ramp is assumed. New loads contribute 14,787 GWh to the annual energy forecast and 1,895 MW to the annual peak Base forecast by 2031. The energy and peak demand impacts of the large load assumptions for 2024-2050 are shown in Tables 2.2-11 and 2.2-12 below.

For the Low forecast, large load additions are included only for projects that had signed contracts at the time the forecast was developed.

Forecast for Oil and Gas Electrification

The Base Case forecast for oil and gas electrification includes load starting at 27 MW in 2024 and ramping to 364 MW by the end of the RAP. Energy impacts level off at about 790 GWh starting in 2030.

Time-of-Use Rates

The Base Case forecast includes an adjustment to the Residential load profile to account for the load-shifting effects of the RE-TOU rate. The impact is weighted by the percentage of customers on the RE-TOU rate. The effects are estimated based on a comparison of load profiles for customers on the R and RE-TOU rates from June 2023 through June 2024. Separate impacts were estimated for Summer and Winter months, with an additional distinction for weekday and weekend. Table 2.2-9 shows the load profile impacts included in the modeling. The lightly shaded area represents the shoulder-peak period and the darker shading represents the on-peak period. The impact of time-of-use rates on customers' load is greater in the Summer months than the Winter months.

The Base Case forecast does not include an adjustment for C-TOU rates since, at the time the forecast was developed, not enough data was available to analyze customers' response to the new rates. The peak demand reduction from C-TOU rates, once fully implemented, is expected to be under 10 MW.

Table 2.2-10 shows the demand impacts associated with the RE-TOU rate adjustments. The first column shows the maximum impact by year, while the second column shows the peak demand impacts at the time of the obligation peak. The impact at the time of the obligation peak declines in 2029 due to a shift in the peak hour, and yields increases to the peak demand forecast starting in 2039 after the system switches to a winter peak.

Table 2.2-9 Residential Time-of-Use Load Profile Impacts

Hourly Percentage of Daily Load												
	Weekday Summer			Weekend Summer			Weekday Winter			Weekday Winter		
Hour Ending	R	RE-TOU	**% Diff**	R	RE-TOU	**% Diff**	R	RE-TOU	**% Diff**	R	RE-TOU	**% Diff**
1	3.0%	3.1%	**2.6%**	3.0%	3.1%	**2.9%**	3.3%	3.3%	**0.7%**	3.3%	3.3%	**0.1%**
2	2.7%	2.8%	**3.0%**	2.7%	2.8%	**3.2%**	3.2%	3.2%	**0.4%**	3.2%	3.2%	**-0.2%**
3	2.5%	2.6%	**3.7%**	2.5%	2.6%	**4.2%**	3.2%	3.2%	**0.2%**	3.1%	3.1%	**-0.5%**
4	2.4%	2.5%	**4.0%**	2.4%	2.5%	**4.1%**	3.3%	3.3%	**0.0%**	3.1%	3.1%	**-0.8%**
5	2.5%	2.5%	**3.6%**	2.3%	2.4%	**3.9%**	3.5%	3.5%	**-0.1%**	3.2%	3.2%	**-1.2%**
6	2.6%	2.7%	**3.3%**	2.4%	2.5%	**3.8%**	3.9%	3.9%	**-0.4%**	3.5%	3.4%	**-1.5%**
7	2.8%	2.9%	**2.7%**	2.6%	2.7%	**3.3%**	4.2%	4.2%	**-0.7%**	3.8%	3.7%	**-1.4%**
8	3.0%	3.1%	**2.2%**	3.0%	3.1%	**3.3%**	4.2%	4.1%	**-0.8%**	4.1%	4.0%	**-0.7%**
9	3.3%	3.3%	**1.5%**	3.4%	3.5%	**2.5%**	4.1%	4.1%	**-0.5%**	4.3%	4.3%	**0.0%**
10	3.6%	3.6%	**0.9%**	3.8%	3.9%	**1.8%**	4.1%	4.1%	**-0.2%**	4.4%	4.4%	**0.6%**
11	4.0%	4.0%	**0.0%**	4.3%	4.4%	**1.1%**	4.1%	4.1%	**0.0%**	4.4%	4.5%	**0.8%**
12	4.5%	4.5%	**-0.7%**	4.8%	4.8%	**-0.1%**	4.1%	4.1%	**-0.1%**	4.5%	4.5%	**0.8%**
13	4.9%	4.8%	**-2.0%**	5.2%	5.1%	**-1.6%**	4.1%	4.0%	**-0.2%**	4.4%	4.5%	**0.8%**
14	5.3%	5.2%	**-2.8%**	5.6%	5.5%	**-2.8%**	4.1%	4.0%	**-0.3%**	4.5%	4.5%	**0.5%**
15	5.7%	5.4%	**-3.6%**	5.9%	5.7%	**-3.6%**	4.2%	4.2%	**-0.4%**	4.5%	4.5%	**0.4%**
16	6.0%	5.8%	**-3.5%**	6.2%	5.9%	**-3.8%**	4.6%	4.5%	**-0.6%**	4.8%	4.8%	**-0.2%**
17	6.2%	6.0%	**-3.2%**	6.2%	6.0%	**-3.4%**	5.2%	5.1%	**-1.2%**	5.2%	5.1%	**-1.0%**
18	6.2%	6.1%	**-2.5%**	6.1%	5.9%	**-2.6%**	5.4%	5.4%	**-1.0%**	5.3%	5.2%	**-0.8%**
19	6.0%	5.9%	**-0.8%**	5.7%	5.6%	**-1.4%**	5.4%	5.4%	**0.1%**	5.2%	5.2%	**-0.1%**
20	5.6%	5.6%	**1.4%**	5.3%	5.3%	**-0.2%**	5.3%	5.3%	**0.8%**	5.0%	5.1%	**0.5%**
21	5.3%	5.3%	**0.8%**	5.0%	5.0%	**0.2%**	5.0%	5.0%	**1.1%**	4.8%	4.8%	**0.6%**
22	4.6%	4.7%	**1.1%**	4.4%	4.5%	**0.9%**	4.4%	4.5%	**1.3%**	4.3%	4.3%	**0.9%**
23	4.0%	4.0%	**1.7%**	3.8%	3.9%	**1.7%**	3.9%	3.9%	**1.3%**	3.8%	3.8%	**1.0%**
24	3.4%	3.5%	**3.0%**	3.3%	3.4%	**3.2%**	3.5%	3.6%	**1.1%**	3.5%	3.5%	**0.6%**

Table 2.2-10 Residential Time-of-Use Demand Forecast Impacts

RE-TOU Demand Impacts (MW)		
	Maximum Demand Impact	Impact at time of Obligation Peak
2024	(76)	(56)
2025	(104)	(77)
2026	(105)	(79)
2027	(106)	(81)
2028	(108)	(82)
2029	(109)	(23)
2030	(112)	(24)
2031	(114)	(24)
2032	(115)	(25)
2033	(117)	(25)
2034	(118)	(26)
2035	(119)	(25)
2036	(120)	(26)
2037	(121)	(26)
2038	(121)	(26)
2039	(122)	22
2040	(122)	22
2041	(123)	22
2042	(124)	22
2043	(124)	29
2044	(125)	29
2045	(124)	30
2046	(126)	30
2047	(127)	30
2048	(128)	30
2049	(128)	17
2050	(129)	18

Wholesale Forecast

Methodology

Forecasts of sales for each rural electric association (“REA”) and municipality are received directly from the customers. The sales are then adjusted for losses to develop the energy forecast. Forecasts of peak demand for each REA and municipality are based on information received from the respective wholesale customers. These forecasts are then incorporated into the Company's hourly load forecast process, as described below.

Summary

As previously shown in Tables 2.2-5 and 2.2-6, wholesale energy and demand are expected to decline through the forecast period. CORE Electric Cooperative (formerly Intermountain Rural Electric Association (“IREA”)) is expected to no longer take power from Public Service by the end of 2025, and Yampa Valley and Grand Valley are expected to leave the Public Service system after 2028. The remaining customers leave the Public Service system after 2042. Figures 2.2-3 and 2.2-4 below graphically depict the energy and demand forecasts for wholesale.

Figure 2.2-3 Wholesale Energy Forecast

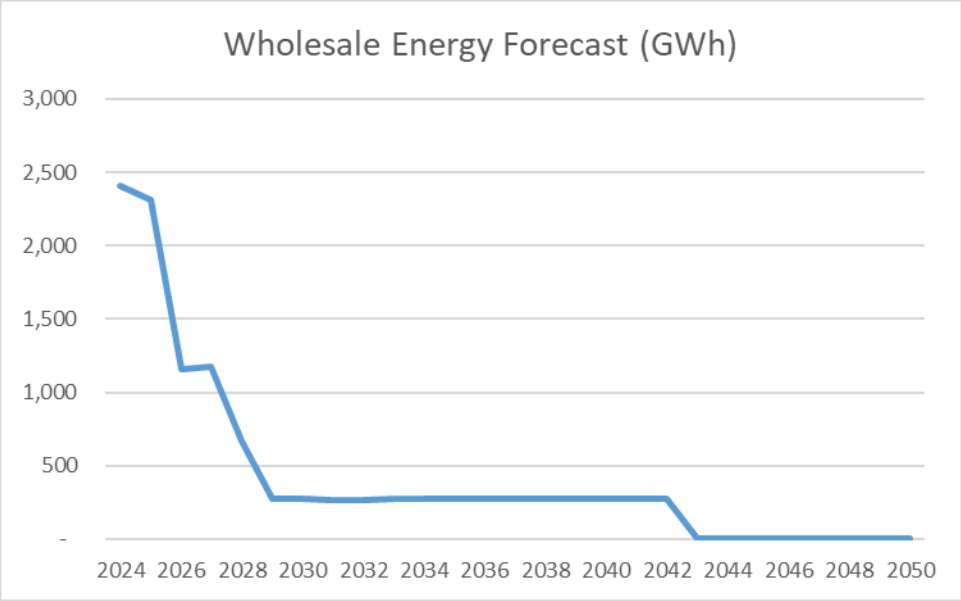
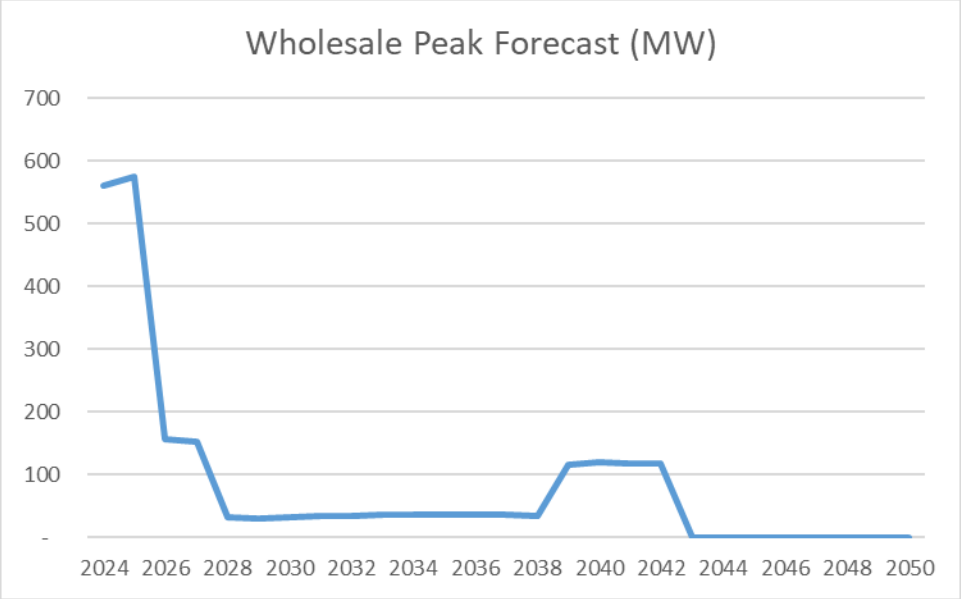


Figure 2.2-4 Wholesale Coincident Peak Demand Forecast



Base Retail Forecast

Methodology

Public Service uses monthly historical customer, sales, and peak demand data by rate class to develop its forecasts. Historical and forecasted economic and demographic data are obtained from IHS Markit. Historical weather data is obtained from the National Oceanic and Atmospheric Administration ("NOAA") and based on weather at Denver International Airport and Stapleton/Central Park.

Forecasted Weather Assumptions

The Company uses a 10-year average of monthly Cooling Degree Days ("CDDs") and Heating Degree Days ("HDDs") at Denver International Airport in its sales models. For this forecast, the 10-year period is from 2014-2023. The Company uses a 30-year average of monthly maximum daily CDDs and HDDs for its peak demand models, based on data at Stapleton/Central Park. For this forecast, the 30-year period is 1994-2023.

Sales and Energy Forecast

Public Service's Residential sales forecast was calculated by multiplying average use per customer times the number of customers. Forecasts of Residential average use and Commercial and Industrial sales (excluding the Primary Standby Service, Transmission General, and Transmission Standby Service rates) were developed using a Statistically-Adjusted End-Use ("SAE") modeling approach. The SAE method entails specifying energy use as a function of the primary end-use variables (heating, cooling, and base use) and the factors that affect these end-use energy requirements.

Each end-use variable (heating, cooling, and base) is defined as the product of an appliance index variable, which indicates relative saturation and efficiency of the stock of appliances, and a utilization variable, which reflects how the stock is utilized. The appliance index variables reflect both changes in saturation resulting from end-use competition, and improvements in appliance efficiency standards. The utilization variables are designed to capture energy demand driven by the use of the appliance stock. For the Residential sector, the primary factors that impact appliance use are weather conditions (for the heating and cooling end uses, as measured by heating degree days and cooling degree days), electricity prices, household income, household size, and average number of billed consumption days. For the Commercial and Industrial sector, the utilization of the stock of equipment is a function of electricity prices, business activity (as measured by Gross Metropolitan Product ("GMP")), weather conditions (for the heating and cooling end uses, as measured by heating degree days and cooling degree days), and average number of billed consumption days.

The Residential use per customer and Commercial and Industrial sales forecast models were estimated by regressing historical monthly use per customer or sales on the Cooling, Heating, and Base variables, monthly binary variables, seasonal binary variables, and

variables designed to estimate the impacts of the COVID-19 pandemic. In addition, the monthly number of Commercial and Industrial customers was included in the Commercial and Industrial sales forecast model. Monthly historical data through December 2023 was used in each of the models. The regression models effectively calibrated the end-use concepts to actual monthly sales. Monthly binary variables were included to account for historical data outliers and seasonal binary variables were included to account for non-weather-related seasonal factors.

Regression models provided the foundation for the customer forecasts of the Residential and the Commercial and Industrial classes. In these models, at least 15 years of monthly historical data was used to conduct the analysis, with service territory population as the independent variable along with occupied multi-family housing units in the Residential regression. The modeled relationships were simulated over the forecast period using projected levels of the independent predictor variables.

The Street Lighting sales forecast was developed by regressing street light sales on service territory population, commercial lighting intensity, monthly seasonal binary variables, and monthly binary variables. The Interdepartmental sales forecast was also developed using a regression model with monthly seasonal binary variables and monthly binary variables as independent variables. Public Authority sales were forecasted based on recent sales levels.

Due to the fewer number of customers and more widely varying business types, the Transmission General Service, Transmission Standby Service, and Primary Standby Service classes were forecasted outside of the SAE modeling framework. The Transmission General Service class was forecasted at a customer level. Each of the individual customers within this class was forecasted based on historical actual sales, the growth trends present in those sales, and input from the account managers who oversee these particular customer accounts. The forecast for the Transmission Standby Service class was developed in a similar fashion, with forecasts developed for each of the individual customers. The Primary Standby Service class was forecasted at the rate class level by analyzing historical annual growth rates, forecasting a future annual growth rate and allocating annual sales to a monthly basis using historical allocators.

The Residential and the Commercial and Industrial sales forecast results were adjusted to reflect the expected impact of DSM programs, the implementation of Integrated Volt-VAr Optimization (“IVVO”), and the incremental increase in adoption of electric vehicles (“EVs”), and electrification associated with the Clean Heat Plan (“BE”). The Commercial and Industrial forecast was also adjusted to include large, new loads. These new load adjustments were developed in conjunction with the Company’s Economic Development team.

Figure 2.2-5 and Table 2.2-11 show the impact of incremental EV adoption, BE, and large loads on retail energy in the Base forecast. These three adjustments significantly increase the outlook for Retail energy. The Retail energy forecast, without these adjustments, is expected to grow at an average rate of 0.6% through the RAP. After the adjustments, the

expected growth rate is 7.0%. By the end of the RAP, EV, BE, and large loads account for 39% of the retail energy forecast, and these adjustments are 59% of the outlook by the end of the forecast period.

Figure 2.2-5 Retail Energy Forecasts

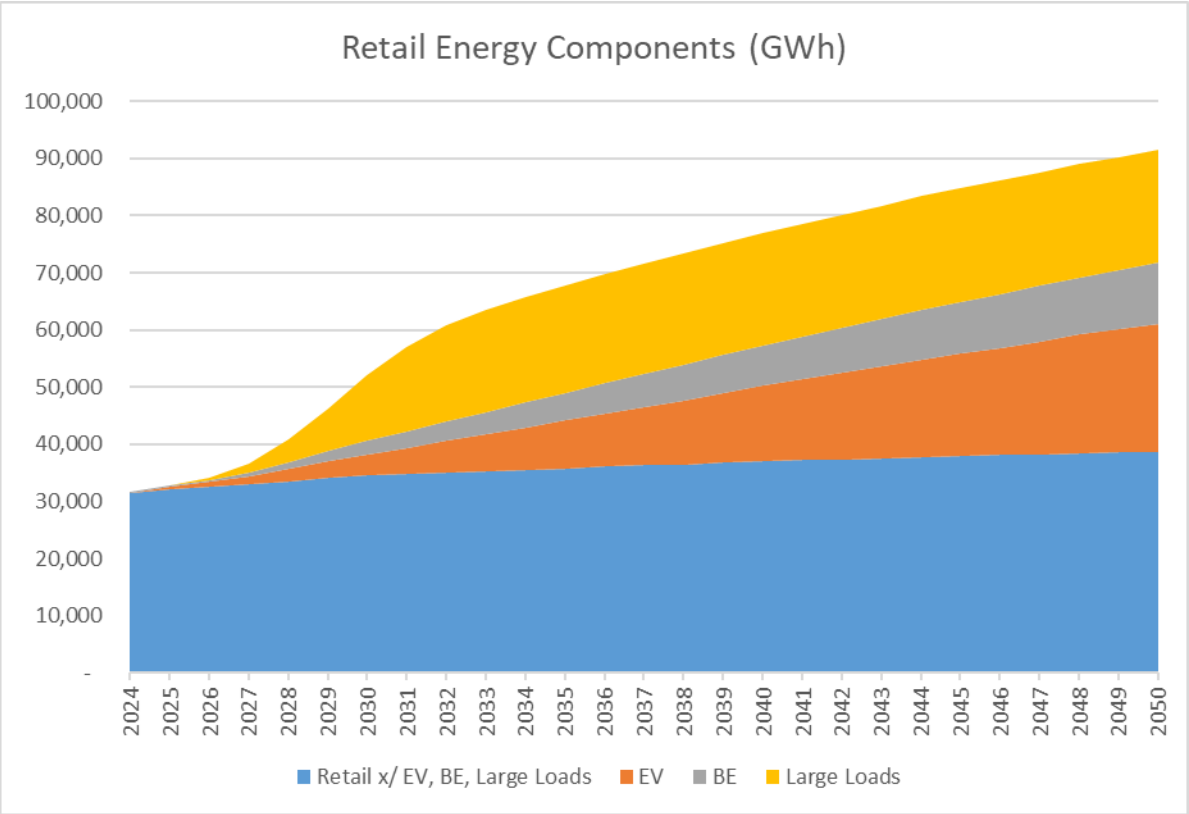


Table 2.2-11 Retail Energy Components

	Retail Energy (GWh)					% of Energy				
	Retail x/ EV, BE, Large Loads	EV	BE	Large Loads	**Total Retail**	Retail x/ EV, BE, Large Loads	EV	BE	Large Loads	**Total Retail**
2024	31,393	169	28	4	**31,594**	99%	1%	0%	0%	**100%**
2025	32,140	516	99	56	**32,810**	98%	2%	0%	0%	**100%**
2026	32,543	942	237	338	**34,060**	96%	3%	1%	1%	**100%**
2027	32,930	1,463	716	1,466	**36,575**	90%	4%	2%	4%	**100%**
2028	33,533	2,109	1,219	3,970	**40,831**	82%	5%	3%	10%	**100%**
2029	34,228	2,873	1,747	7,496	**46,344**	74%	6%	4%	16%	**100%**
2030	34,580	3,718	2,292	11,447	**52,036**	66%	7%	4%	22%	**100%**
2031	34,823	4,599	2,835	14,787	**57,044**	61%	8%	5%	26%	**100%**
2032	35,119	5,587	3,364	16,826	**60,896**	58%	9%	6%	28%	**100%**
2033	35,321	6,475	3,876	17,793	**63,466**	56%	10%	6%	28%	**100%**
2034	35,581	7,410	4,373	18,355	**65,719**	54%	11%	7%	28%	**100%**
2035	35,798	8,379	4,854	18,744	**67,776**	53%	12%	7%	28%	**100%**
2036	36,104	9,335	5,322	19,130	**69,891**	52%	13%	8%	27%	**100%**
2037	36,290	10,253	5,776	19,331	**71,650**	51%	14%	8%	27%	**100%**
2038	36,502	11,209	6,220	19,489	**73,421**	50%	15%	8%	27%	**100%**
2039	36,750	12,180	6,656	19,578	**75,163**	49%	16%	9%	26%	**100%**
2040	37,038	13,208	7,082	19,680	**77,008**	48%	17%	9%	26%	**100%**
2041	37,186	14,165	7,501	19,677	**78,528**	47%	18%	10%	25%	**100%**
2042	37,362	15,140	7,913	19,724	**80,138**	47%	19%	10%	25%	**100%**
2043	37,562	16,055	8,329	19,775	**81,720**	46%	20%	10%	24%	**100%**
2044	37,804	17,010	8,728	19,874	**83,417**	45%	20%	10%	24%	**100%**
2045	37,910	17,883	9,101	19,847	**84,741**	45%	21%	11%	23%	**100%**
2046	38,082	18,798	9,415	19,869	**86,164**	44%	22%	11%	23%	**100%**
2047	38,262	19,707	9,723	19,874	**87,566**	44%	23%	11%	23%	**100%**
2048	38,492	20,663	10,028	19,929	**89,112**	43%	23%	11%	22%	**100%**
2049	38,578	21,495	10,330	19,874	**90,276**	43%	24%	11%	22%	**100%**
2050	38,720	22,364	10,682	19,874	**91,640**	42%	24%	12%	22%	**100%**

Demand Forecast

The Company's demand forecast is developed using an hourly forecasting, or "8760" approach. This approach uses hourly profiles of each major component of PSCo's load forecast to determine the magnitude and timing of monthly peaks. Each component (Residential, Non-Residential, EV, BE, large new loads, DSM, and Wholesale) grows at a different rate over the forecast timeframe, and each has a unique hourly shape that impacts overall system load. The "8760" takes all of these effects into account, aggregates all components' load, and then identifies the monthly peaks and annual peaks. During this process, the Residential profiles are adjusted for the impact of time-of-use pricing.

Figure 2.2-6 and Table 2.2-12 show the impact of incremental EV adoption, BE, and large loads on retail peak demand in the Base forecast. The Retail peak forecast, without these adjustments, is expected to decline at an average rate of 0.4% through the RAP. After the adjustments, the expected growth rate is 3.9%. By the end of the RAP, EV, BE, and large loads account for 28% of the retail peak forecast. The system is expected to switch to winter peaking in 2039 and peak demand is driven by increases in EV adoption and BE as the peak hour moves to times of lower demand without these adjustments. By the end of the forecast period, EV, BE, and large loads make up 69% of the peak demand forecast.

Figure 2.2-6 Retail Peak Forecasts

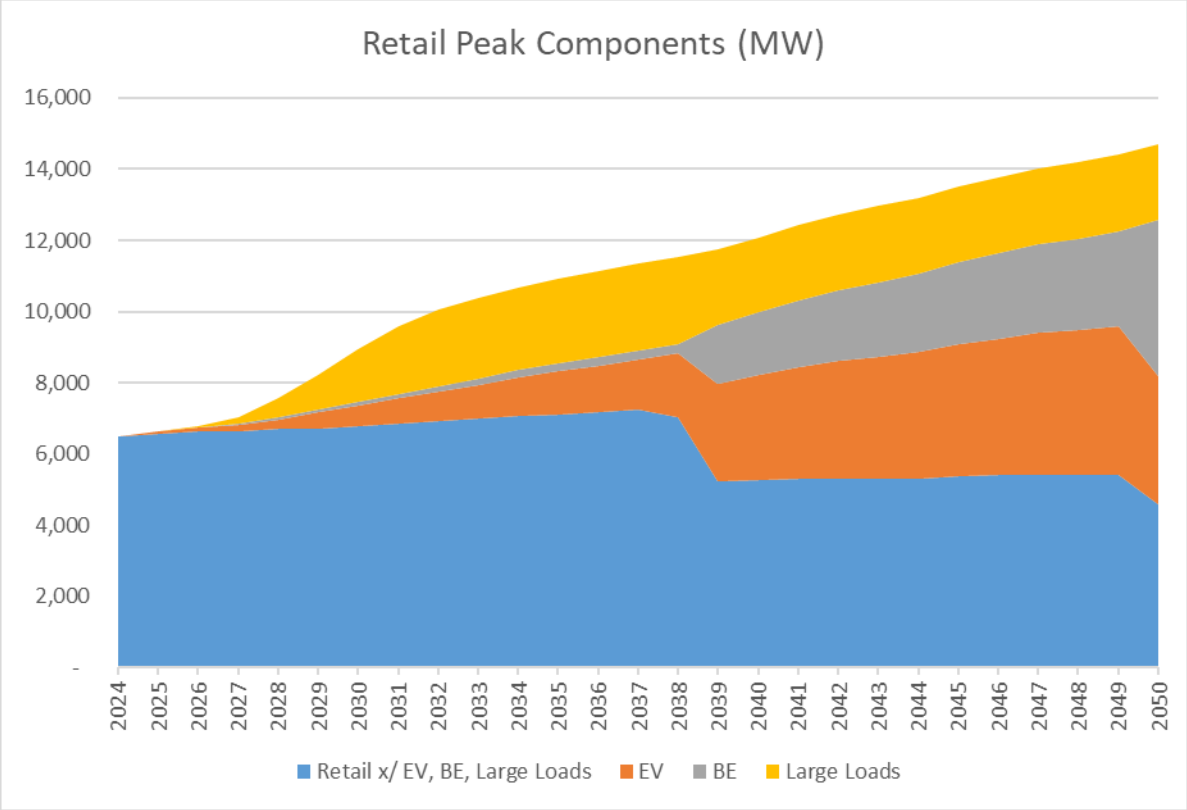


Table 2.2-12 Retail Peak Components

	Retail Peak Demand (MW)					% of Peak				
	Retail x/ EV, BE, Large Loads	EV	BE	Large Loads	**Total Retail**	Retail x/ EV, BE, Large Loads	EV	BE	Large Loads	**Total Retail**
2024	6,478	19	1	1	**6,499**	100%	0%	0%	0%	**100%**
2025	6,574	57	3	6	**6,640**	99%	1%	0%	0%	**100%**
2026	6,638	103	8	40	**6,789**	98%	2%	0%	1%	**100%**
2027	6,631	173	35	197	**7,036**	94%	2%	0%	3%	**100%**
2028	6,718	251	61	534	**7,565**	89%	3%	1%	7%	**100%**
2029	6,727	459	81	971	**8,238**	82%	6%	1%	12%	**100%**
2030	6,787	585	109	1,478	**8,959**	76%	7%	1%	16%	**100%**
2031	6,854	710	134	1,895	**9,593**	71%	7%	1%	20%	**100%**
2032	6,911	839	157	2,133	**10,040**	69%	8%	2%	21%	**100%**
2033	6,987	961	179	2,253	**10,380**	67%	9%	2%	22%	**100%**
2034	7,063	1,087	199	2,323	**10,672**	66%	10%	2%	22%	**100%**
2035	7,113	1,209	218	2,373	**10,914**	65%	11%	2%	22%	**100%**
2036	7,176	1,307	235	2,414	**11,132**	64%	12%	2%	22%	**100%**
2037	7,259	1,409	252	2,444	**11,364**	64%	12%	2%	22%	**100%**
2038	7,052	1,770	247	2,445	**11,515**	61%	15%	2%	21%	**100%**
2039	5,227	2,756	1,636	2,112	**11,731**	45%	23%	14%	18%	**100%**
2040	5,289	2,943	1,741	2,117	**12,089**	44%	24%	14%	18%	**100%**
2041	5,307	3,135	1,862	2,122	**12,426**	43%	25%	15%	17%	**100%**
2042	5,316	3,293	1,973	2,128	**12,711**	42%	26%	16%	17%	**100%**
2043	5,324	3,415	2,083	2,133	**12,955**	41%	26%	16%	16%	**100%**
2044	5,323	3,554	2,179	2,137	**13,194**	40%	27%	17%	16%	**100%**
2045	5,394	3,687	2,295	2,139	**13,515**	40%	27%	17%	16%	**100%**
2046	5,411	3,836	2,387	2,141	**13,775**	39%	28%	17%	16%	**100%**
2047	5,423	3,988	2,480	2,141	**14,032**	39%	28%	18%	15%	**100%**
2048	5,404	4,082	2,559	2,141	**14,187**	38%	29%	18%	15%	**100%**
2049	5,406	4,190	2,657	2,141	**14,394**	38%	29%	18%	15%	**100%**
2050	4,586	3,590	4,382	2,127	**14,686**	31%	24%	30%	14%	**100%**

Note: System becomes winter peaking in 2039

Low Scenario

Public Service's Low scenario energy and peak forecast is based on the slower adoption of EVs, oil and gas electrification, and additional large loads, as discussed earlier. These large load assumptions were developed in conjunction with the Company's Economic Development team and include a conservative estimate of the large load requests that are likely to connect to the system.

Table 2.2-13 shows the energy and peak impacts of the lower EV adoption, oil and gas electrification, and large loads, as compared to the Base Case. The peak impacts include the effects of the shift in peak hours.

Table 2.2-13 Impacts of Lower Oil and Gas Electrification, EVs, and Large Loads in Low Forecast

	Peak (MW)						Retail Energy (GWh)					
	Base	O&G Elec/Other Retail	EV	BE	Large Loads	**Low**	Base	O&G Elec/Other Retail	EV	BE	Large Loads	**Low**
2024	7,060	(12)	(8)	-	-	**7,041**	34,003	(57)	(89)	-	-	**33,857**
2025	7,215	(21)	(21)	-	-	**7,173**	35,124	(117)	(266)	-	(6)	**34,736**
2026	6,945	(30)	(37)	-	(10)	**6,869**	35,216	(173)	(466)	-	(111)	**34,466**
2027	7,189	43	(64)	0	(147)	**7,021**	37,749	(312)	(685)	-	(1,075)	**35,677**
2028	7,597	20	(84)	3	(458)	**7,077**	41,498	(474)	(925)	-	(3,370)	**36,730**
2029	8,268	33	(206)	11	(854)	**7,252**	46,620	(737)	(1,158)	-	(6,599)	**38,127**
2030	8,992	37	(240)	15	(1,324)	**7,479**	52,315	(796)	(1,360)	-	(10,245)	**39,914**
2031	9,628	(109)	(173)	-	(1,713)	**7,633**	57,312	(796)	(1,529)	-	(13,343)	**41,644**
2032	10,074	(109)	(177)	-	(1,921)	**7,867**	61,161	(797)	(1,700)	-	(15,142)	**43,522**
2033	10,416	(109)	(190)	-	(2,006)	**8,111**	63,740	(795)	(1,865)	-	(15,836)	**45,243**
2034	10,708	(109)	(216)	-	(2,042)	**8,341**	65,993	(793)	(2,129)	-	(16,125)	**46,945**
2035	10,950	(109)	(241)	-	(2,062)	**8,538**	68,050	(792)	(2,399)	-	(16,274)	**48,584**
2036	11,168	(109)	(263)	-	(2,080)	**8,716**	70,165	(794)	(2,674)	-	(16,471)	**50,226**
2037	11,400	(109)	(286)	-	(2,090)	**8,916**	71,925	(791)	(2,938)	-	(16,514)	**51,681**
2038	11,549	159	(573)	22	(2,074)	**9,082**	73,695	(791)	(3,213)	-	(16,536)	**53,155**
2039	11,846	388	(1,115)	(47)	(1,779)	**9,293**	75,438	(790)	(3,492)	-	(16,541)	**54,615**
2040	12,208	350	(1,206)	(53)	(1,779)	**9,521**	77,282	(791)	(3,787)	-	(16,593)	**56,111**
2041	12,544	359	(1,303)	(59)	(1,780)	**9,760**	78,802	(789)	(4,060)	-	(16,551)	**57,402**
2042	12,828	368	(1,396)	(65)	(1,781)	**9,954**	80,412	(789)	(4,339)	-	(16,555)	**58,729**
2043	12,955	(100)	(1,094)	-	(1,782)	**9,978**	81,720	(790)	(4,577)	-	(16,560)	**59,792**
2044	13,194	(99)	(1,134)	-	(1,782)	**10,178**	83,417	(791)	(4,796)	-	(16,612)	**61,218**
2045	13,515	(100)	(1,172)	-	(1,782)	**10,461**	84,741	(789)	(4,974)	-	(16,568)	**62,411**
2046	13,775	(100)	(1,212)	-	(1,782)	**10,681**	86,164	(788)	(5,164)	-	(16,570)	**63,642**
2047	14,032	(100)	(1,254)	-	(1,783)	**10,896**	87,566	(788)	(5,355)	-	(16,570)	**64,853**
2048	14,187	(99)	(1,290)	-	(1,783)	**11,015**	89,112	(789)	(5,567)	-	(16,617)	**66,139**
2049	14,394	(936)	(1,865)	1,531	(1,785)	**11,337**	90,276	(787)	(5,756)	-	(16,570)	**67,162**
2050	14,686	(79)	(1,177)	-	(1,771)	**11,659**	91,640	(786)	(5,975)	-	(16,570)	**68,308**

System Load Shapes

Figures 2.2-7 through 2.2-10 show the hourly system loads for the Base Case summer and winter peak days in 2025, 2030. 2040, and 2050.

Figure 2.2-7 2025 Peak Day Load Shape

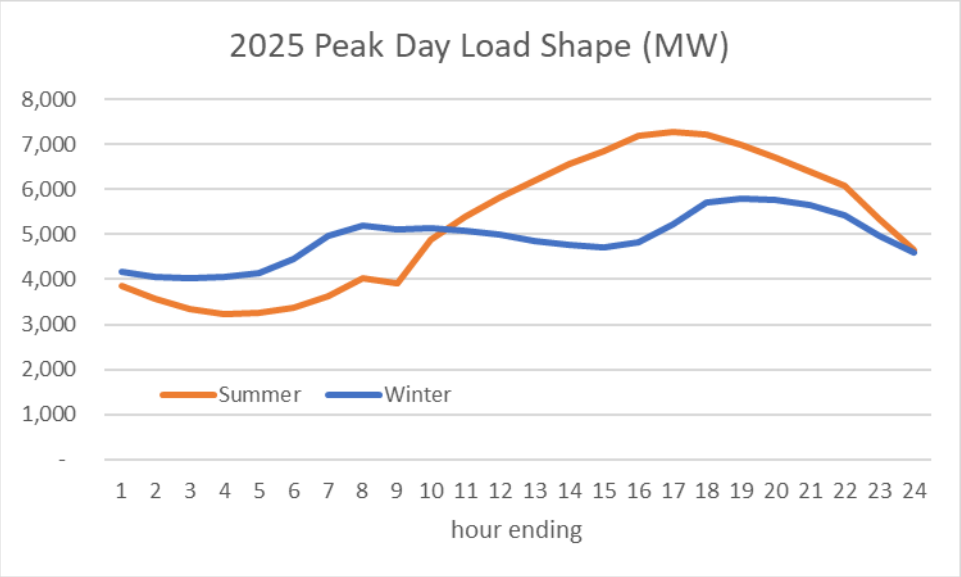


Figure 2.2-8 2030 Peak Day Load Shape

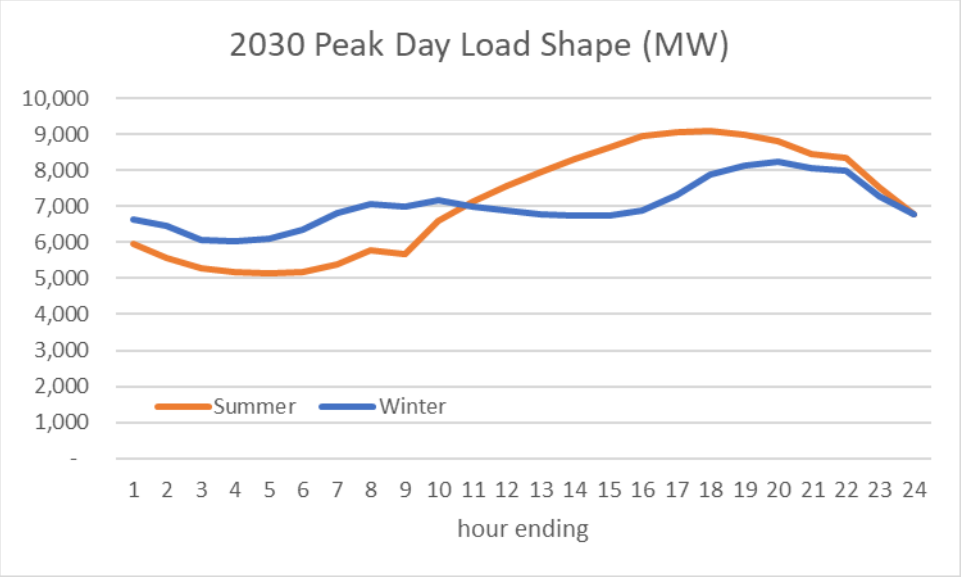


Figure 2.2-9 2040 Peak Day Load Shape

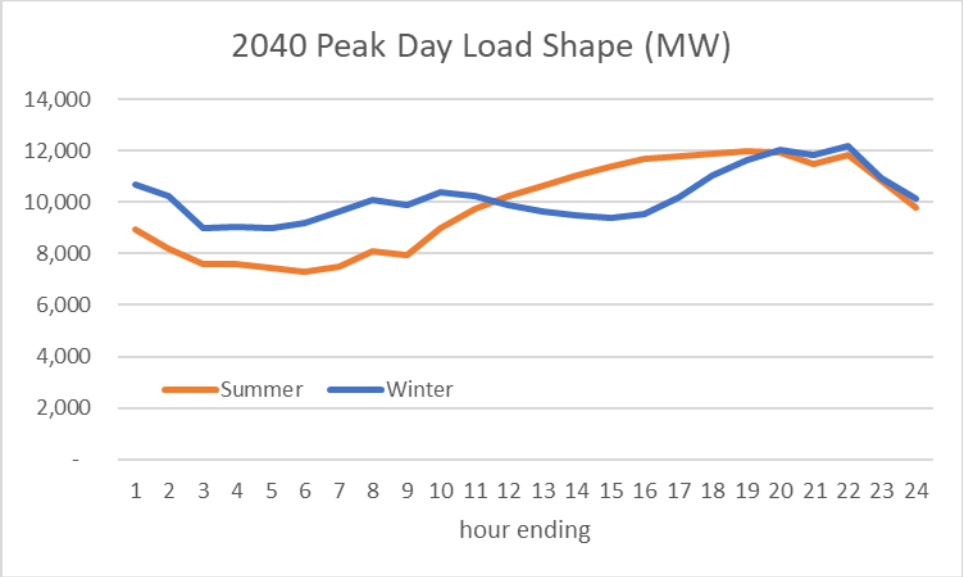
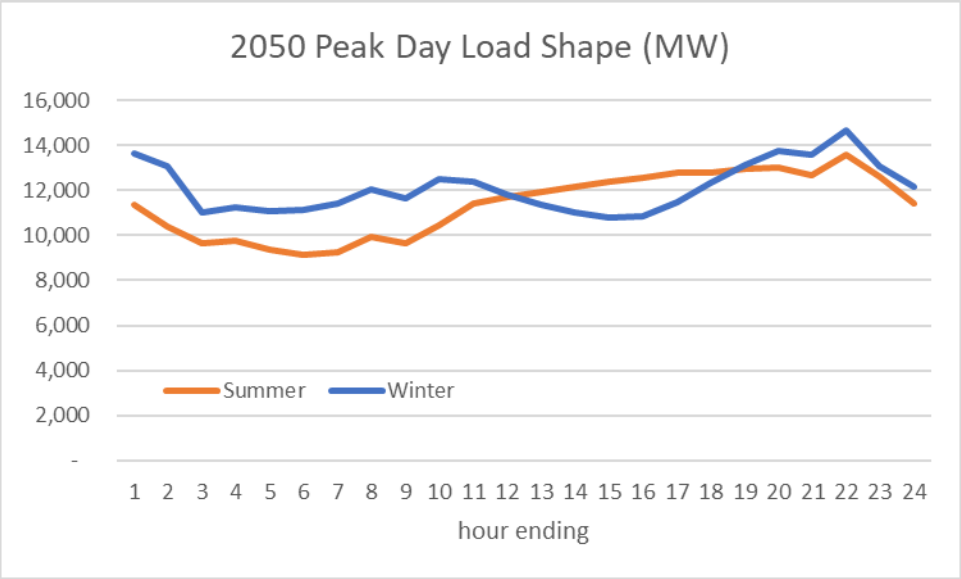


Figure 2.2-10 2050 Peak Day Load Shape



These illustrations show the change in both the overall level of demand as well as the peak day load shapes through time. The changes are driven by the three main load modifiers assumed in the forecast: electric vehicle charging, beneficial electrification, and large loads. Figures 2.2-11 and 2.2-12 show the impacts of these load modifiers on the summer and winter peak days in 2050.

Figure 2.2-11 2050 Summer Peak Day Load Shape by Concept

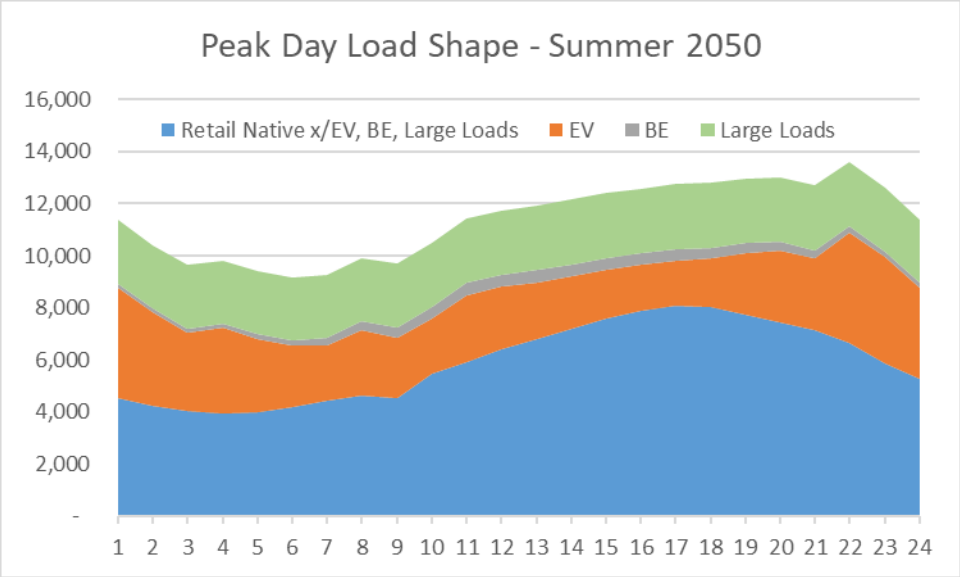
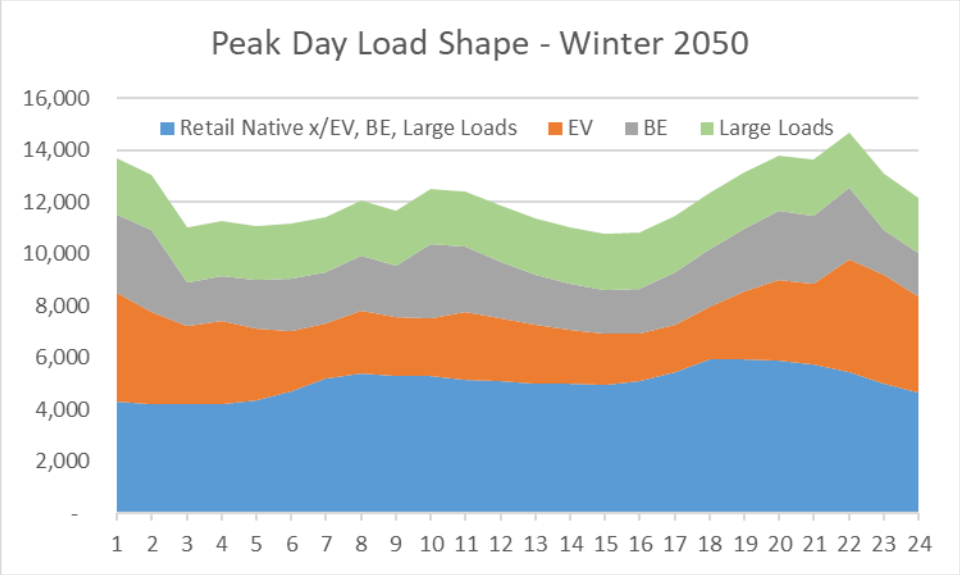


Figure 2.2-12 2050 Winter Peak Day Load Shape by Concept



Comparison to 2021 ERP

Table 2.2-14 and Figures 2.2-13 and 2.2-14 show a comparison of the current Base, Low, and 2021 ERP forecasts.

Table 2.2-14 Base and Planning Forecast Comparisons with 2021 ERP

	Peak Demand (MW)			Annual Energy (GWh)		
	2021 ERP	Base	Low	2021 ERP	Base	Low
2023	6,951	7,008	7,008	33,151	33,298	33,298
2024	6,978	7,060	7,041	33,766	34,003	33,857
2025	7,031	7,215	7,173	34,170	35,124	34,736
2026	6,906	6,945	6,869	33,737	35,216	34,466
2027	6,986	7,189	7,021	34,131	37,749	35,677
2028	7,063	7,597	7,077	34,685	41,498	36,730
2029	7,130	8,268	7,252	35,104	46,620	38,127
2030	7,219	8,992	7,479	35,627	52,315	39,914
2031	7,306	9,628	7,633	36,178	57,312	41,644
2032	7,413	10,074	7,867	36,895	61,161	43,522
2033	7,478	10,416	8,111	37,462	63,740	45,243
2034	7,558	10,708	8,341	38,118	65,993	46,945
2035	7,665	10,950	8,538	38,899	68,050	48,584
2036	7,774	11,168	8,716	39,805	70,165	50,226
2037	7,862	11,400	8,916	40,516	71,925	51,681
2038	7,963	11,549	9,082	41,313	73,695	53,155
2039	8,069	11,846	9,293	42,069	75,438	54,615
2040	8,159	12,208	9,521	42,823	77,282	56,111
2041	8,216	12,544	9,760	43,379	78,802	57,402
2042	8,285	12,828	9,954	44,002	80,412	58,729
2043	8,129	12,955	9,978	43,298	81,720	59,792
2044	8,195	13,194	10,178	43,969	83,417	61,218
2045	8,245	13,515	10,461	44,466	84,741	62,411
2046	8,313	13,775	10,681	45,091	86,164	63,642
2047	8,389	14,032	10,896	45,762	87,566	64,853
2048	8,461	14,187	11,015	46,520	89,112	66,139
2049	8,509	14,394	11,337	46,991	90,276	67,162
2050		14,686	11,659		91,640	68,308

Figure 2.2-13 Peak Forecast Comparisons with 2021 ERP

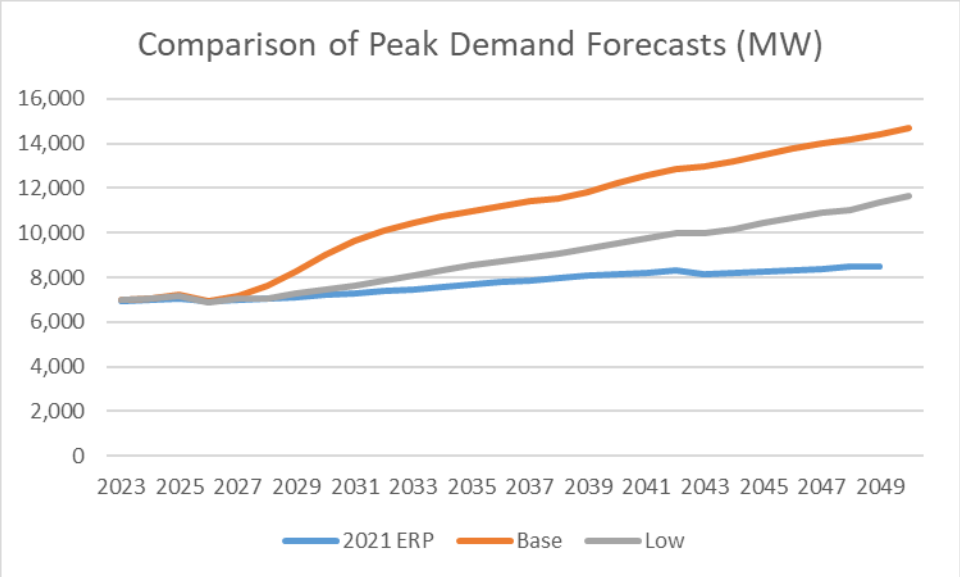
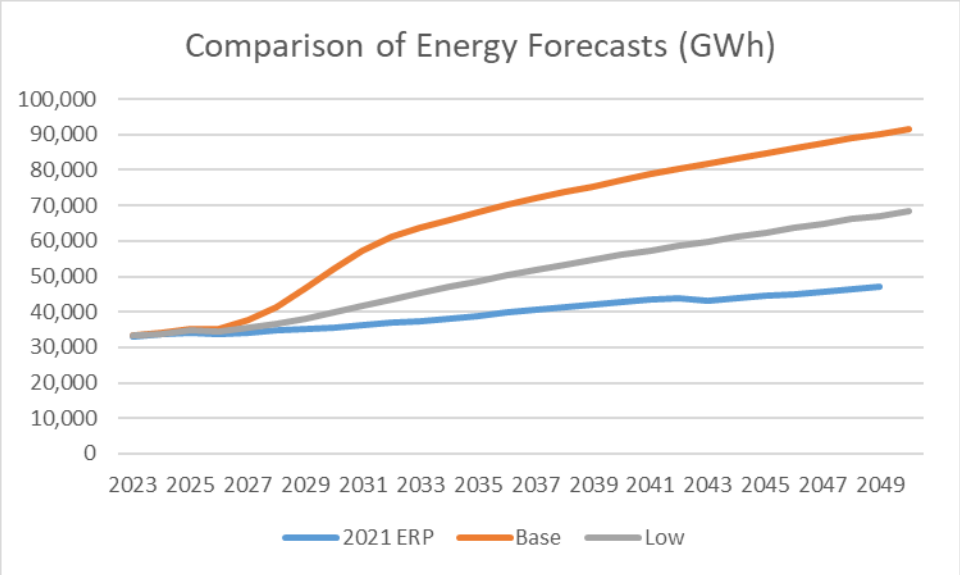


Figure 2.2-14 Energy Forecast Comparisons with 2021 ERP



Additional Energy and Demand Forecast Information

Tables 2.2-15 through 2.2-19 present additional information associated with the energy and demand forecasts.

Table 2.2-1515 Base Case and Low Coincident Summer and Winter Peak Demand

	Coincident Summer Peak Demand (MW)		Coincident Winter Peak Demand (MW)	
	Base Case	Low	Base Case	Low
2024	7,060	7,041	5,596	5,559
2025	7,215	7,173	5,806	5,729
2026	6,945	6,869	5,656	5,500
2027	7,189	7,021	6,107	5,718
2028	7,597	7,077	6,616	5,830
2029	8,268	7,252	7,459	6,213
2030	8,992	7,479	8,232	6,573
2031	9,628	7,633	8,893	6,932
2032	10,074	7,867	9,374	7,273
2033	10,416	8,111	9,797	7,614
2034	10,708	8,341	10,195	7,952
2035	10,950	8,538	10,555	8,257
2036	11,168	8,716	10,871	8,517
2037	11,400	8,916	11,176	8,780
2038	11,549	9,082	11,486	9,020
2039	11,773	9,281	11,846	9,293
2040	11,939	9,416	12,208	9,521
2041	12,109	9,551	12,544	9,760
2042	12,307	9,672	12,828	9,954
2043	12,479	9,755	12,955	9,978
2044	12,650	9,852	13,194	10,178
2045	12,802	9,978	13,515	10,461
2046	12,971	10,060	13,775	10,681
2047	13,135	10,133	14,032	10,896
2048	13,291	10,197	14,187	11,015
2049	13,431	10,265	14,394	11,337
2050	13,618	10,379	14,686	11,659

Table 2.2-16 Base Case: Energy/Coincident Summer Demand/Winter Peak Demand by Major Customer Class

	Energy (GWh)				Coincident Summer Peak Demand (MW)				Coincident Winter Peak Demand (MW)			
Year	Residential	Non-Residential	Resale	Total	Residential	Non-Residential	Resale	Total	Residential	Non-Residential	Resale	Total
2024	11,401	20,192	2,409	34,003	3,183	3,316	561	7,060	2,240	2,660	696	5,596
2025	11,724	21,086	2,314	35,124	3,232	3,408	575	7,215	2,310	2,790	707	5,806
2026	12,097	21,963	1,156	35,216	3,280	3,509	156	6,945	2,372	2,973	311	5,656
2027	12,775	23,800	1,174	37,749	3,306	3,729	153	7,189	2,500	3,290	317	6,107
2028	13,637	27,195	667	41,498	3,390	4,175	32	7,597	2,754	3,717	146	6,616
2029	14,545	31,800	276	46,620	3,456	4,782	30	8,268	3,000	4,308	151	7,459
2030	15,536	36,501	278	52,315	3,580	5,379	33	8,992	3,240	4,838	155	8,232
2031	16,557	40,487	268	57,312	3,707	5,886	35	9,628	3,481	5,256	156	8,893
2032	17,624	43,271	265	61,161	3,823	6,217	35	10,074	3,698	5,521	155	9,374
2033	18,649	44,817	274	63,740	3,949	6,432	36	10,416	3,938	5,704	155	9,797
2034	19,697	46,021	274	65,993	4,074	6,598	36	10,708	4,166	5,873	156	10,195
2035	20,710	47,066	274	68,050	4,178	6,736	36	10,950	4,372	6,026	156	10,555
2036	21,741	48,150	274	70,165	4,269	6,863	36	11,168	4,549	6,166	156	10,871
2037	22,715	48,936	274	71,925	4,381	6,983	36	11,400	4,727	6,293	155	11,176
2038	23,701	49,720	274	73,695	4,274	7,241	35	11,549	4,835	6,536	114	11,486
2039	24,696	50,467	274	75,438	4,354	7,384	35	11,773	5,049	6,682	115	11,846
2040	25,725	51,283	274	77,282	4,429	7,475	35	11,939	5,262	6,827	119	12,208
2041	26,670	51,857	274	78,802	4,505	7,569	35	12,109	5,478	6,948	118	12,544
2042	27,668	52,470	274	80,412	4,511	7,764	32	12,307	5,657	7,054	117	12,828
2043	28,649	53,071	0	81,720	4,606	7,873	0	12,479	5,810	7,145	0	12,955
2044	29,644	53,773	0	83,417	4,679	7,971	0	12,650	5,957	7,237	0	13,194
2045	30,530	54,212	0	84,741	4,718	8,084	0	12,802	6,154	7,361	0	13,515
2046	31,418	54,746	0	86,164	4,808	8,163	0	12,971	6,310	7,465	0	13,775
2047	32,299	55,267	0	87,566	4,872	8,262	0	13,135	6,471	7,561	0	14,032
2048	33,220	55,892	0	89,112	4,929	8,362	0	13,291	6,552	7,634	0	14,187
2049	34,023	56,253	0	90,276	4,979	8,453	0	13,431	6,679	7,715	0	14,394
2050	34,928	56,712	0	91,640	5,081	8,538	0	13,618	7,618	7,068	0	14,686

Table 2.2-1717 Base Case: Intra-Utility Energy and Capacity Use

(at the Time of Coincident Summer and Winter Peak Demand)

	Energy (GWh)		Coincident Summer Demand (MW)		Coincident Winter Demand (MW)	
	Interdepartment	Company Use	Interdepartment	Company Use	Interdepartment	Company Use
2024	3	21	1	2	3	5
2025	3	21	1	2	3	5
2026	3	21	1	2	3	5
2027	3	21	1	2	3	5
2028	3	21	1	2	3	5
2029	3	21	1	2	3	5
2030	3	21	1	2	3	5
2031	3	21	1	2	3	5
2032	3	21	1	2	3	5
2033	3	21	1	2	3	5
2034	3	21	1	2	3	5
2035	3	21	1	2	3	5
2036	3	21	1	2	3	5
2037	3	21	1	2	3	5
2038	3	21	1	2	3	5
2039	3	21	1	2	3	5
2040	3	21	1	2	3	5
2041	3	21	1	2	3	5
2042	3	21	1	2	3	5
2043	3	21	1	2	3	5
2044	3	21	1	2	3	5
2045	3	21	1	2	3	5
2046	3	21	1	2	3	5
2047	3	21	1	2	3	5
2048	3	21	1	2	3	5
2049	3	21	1	2	3	5
2050	3	21	1	2	3	5

Table 2.2-18 Base Case: Losses by Major Customer Class

	Energy Losses (GWh)			Coincident Summer Demand Losses (MW)			Coincident Winter Demand Losses (MW)		
Year	Residential	Non-Residential	Resale	Residential	Non-Residential	Resale	Residential	Non-Residential	Resale
2024	687	1,034	41	227	210	12	160	169	15
2025	707	1,071	39	231	216	12	165	177	15
2026	730	1,103	20	234	222	3	169	188	7
2027	770	1,159	20	236	236	3	179	209	7
2028	822	1,248	12	242	265	1	197	236	3
2029	877	1,363	5	247	303	1	214	273	3
2030	937	1,471	5	256	341	1	231	307	3
2031	998	1,565	5	265	373	1	249	333	3
2032	1,062	1,642	5	273	394	1	264	350	3
2033	1,124	1,692	5	282	408	1	281	362	3
2034	1,186	1,739	5	291	418	1	297	372	3
2035	1,246	1,784	5	298	427	1	312	382	3
2036	1,308	1,831	5	305	435	1	325	391	3
2037	1,366	1,868	5	313	443	1	338	399	3
2038	1,425	1,906	5	305	459	1	345	414	2
2039	1,485	1,946	5	311	468	1	361	424	2
2040	1,547	1,989	5	316	474	1	376	433	3
2041	1,604	2,023	5	322	480	1	391	440	3
2042	1,664	2,057	5	322	492	1	404	447	3
2043	1,723	2,089	0	329	499	0	415	453	0
2044	1,782	2,126	0	334	505	0	425	459	0
2045	1,836	2,153	0	337	512	0	439	467	0
2046	1,889	2,183	0	343	517	0	451	473	0
2047	1,943	2,212	0	348	524	0	462	479	0
2048	1,998	2,245	0	352	530	0	468	484	0
2049	2,047	2,268	0	356	536	0	477	489	0
2050	2,102	2,294	0	363	541	0	544	448	0

Note: System Loss estimates cannot be made for the transmission and distribution levels because the forecast was not developed at the transmission and distribution voltage level.

Table 2.2-19 Forecast Adjustments for DSM

	Forecast Adjustments for DSM		
	Energy Savings (GWh)	Coincident Summer Demand Savings (MW)	Coincident Winter Demand Savings (MW)
2024	(446)	(77)	(58)
2025	(886)	(153)	(116)
2026	(1,328)	(230)	(185)
2027	(1,682)	(278)	(235)
2028	(2,028)	(340)	(288)
2029	(2,372)	(390)	(338)
2030	(2,711)	(450)	(387)
2031	(3,040)	(503)	(433)
2032	(3,359)	(552)	(479)
2033	(3,669)	(607)	(524)
2034	(3,972)	(650)	(570)
2035	(4,142)	(677)	(584)
2036	(4,298)	(699)	(595)
2037	(4,436)	(711)	(604)
2038	(4,598)	(630)	(583)
2039	(4,438)	(614)	(565)
2040	(4,289)	(593)	(549)
2041	(4,148)	(580)	(532)
2042	(4,066)	(534)	(520)
2043	(3,989)	(525)	(510)
2044	(3,914)	(517)	(502)
2045	(3,842)	(516)	(495)
2046	(3,778)	(496)	(486)
2047	(3,720)	(489)	(479)
2048	(3,668)	(484)	(471)
2049	(3,621)	(478)	(465)
2050	(3,579)	(474)	(353)

Forecast Accuracy

Public Service reviews its demand and energy forecasts for accuracy annually. Tables 2.2-20 through 2.2-27 on the following pages compare the actual energy and demand forecasts to the forecasted energy and system demands, as required by the ERP rules. The Adjusted Actual Demand column in the summer peak demand table (Table 2.2-22) accounts for the additional load served due to Comanche 3 and Holy Cross being offline at the time of the peak in 2019 and 2020. The forecasts assume Comanche 3 will be operational, so this adjustment allows for a more direct comparison to the forecasts. Figures 2.2-15 through 2.2-17 contain a graphical description of the forecasts.

Table 2.2-20 Native Energy Forecast Comparison (GWh)

	Actual Energy	2023 Forecast	2022 Forecast	2021 Forecast	2020 Forecast	2019 Forecast
2019	33,282					33,216
2020	34,319				33,238	33,710
2021	33,679			33,109	33,101	33,454
2022	34,226		33,535	32,972	33,072	33,667
2023	32,972	33,550	33,293	32,989	33,386	34,030

Table 2.2-21 Forecast Energy Less Actual Energy (GWh)

	Actual less Forecast					Percent Difference				
	2023 Forecast	2022 Forecast	2021 Forecast	2020 Forecast	2019 Forecast	2023 Forecast	2022 Forecast	2021 Forecast	2020 Forecast	2019 Forecast
2019					-66					-0.2%
2020				-1,081	-609				-3.3%	-1.8%
2021			-570	-578	-225			-1.7%	-1.7%	-0.7%
2022		-690	-1,253	-1,154	-559		-2.1%	-3.8%	-3.5%	-1.7%
2023	578	321	18	414	1,058	1.7%	1.0%	0.1%	1.2%	3.1%

Table 2.2-22 Coincident Summer Demand Forecast Comparison (MW)

	Adj Actual Demand	Actual Demand	2023 Forecast	2022 Forecast	2021 Forecast	2020 Forecast	2019 Forecast
2019	6,743	6,992					6,795
2020	6,753	7,002				7,024	6,803
2021	7,195	7,195			6,968	6,926	6,806
2022	6,991	6,991		7,126	6,999	6,923	6,840
2023	7,008	7,008	7,153	7,094	6,970	6,929	6,887

Table 2.2-23 Forecast Demand Less Actual Summer Native Peak Demand (MW)

	Actual less Forecast (MW)					Percent Difference				
	2023 Forecast	2022 Forecast	2021 Forecast	2020 Forecast	2019 Forecast	2023 Forecast	2022 Forecast	2021 Forecast	2020 Forecast	2019 Forecast
2019					-197					-2.9%
2020				22	-199				0.3%	-2.9%
2021			-227	-269	-389			-3.3%	-3.9%	-5.7%
2022		135	7	-69	-152		1.9%	0.1%	-1.0%	-2.2%
2023	144	86	-38	-79	-121	2.0%	1.2%	-0.5%	-1.1%	-1.8%

Table 2.2-24 Weather Normalized Coincident Summer Demand Forecast Comparison (MW)

	Adj WN Demand	WN Demand	2023 Forecast	2022 Forecast	2021 Forecast	2020 Forecast	2019 Forecast
2019	6,801	7,050					6,795
2020	6,858	7,107				7,024	6,803
2021	7,176	7,176			6,968	6,926	6,806
2022	7,043	7,043		7,126	6,999	6,923	6,840
2023	7,062	7,062	7,153	7,094	6,970	6,929	6,887

Table 2.2-25 Forecast Demand Less Actual Weather Normalized Summer Demand (MW)

	Actual less Forecast (MW)					Percent Difference				
	2023 Forecast	2022 Forecast	2021 Forecast	2020 Forecast	2019 Forecast	2023 Forecast	2022 Forecast	2021 Forecast	2020 Forecast	2019 Forecast
2019					-255					-3.7%
2020				-83	-304				-1.2%	-4.5%
2021			-209	-251	-370			-3.0%	-3.6%	-5.4%
2022		83	-45	-121	-204		1.2%	-0.6%	-1.7%	-3.0%
2023	91	32	-91	-132	-174	1.3%	0.5%	-1.3%	-1.9%	-2.5%

Table 2.2-26 Coincident Winter Demand Forecast Comparison (MW)

	Actual Demand	2023 Forecast	2022 Forecast	2021 Forecast	2020 Forecast	2019 Forecast
2019	5,027					5,304
2020	5,176				5,354	5,292
2021	5,130			5,263	5,376	5,294
2022	5,535		5,322	5,366	5,379	5,298
2023	5,383	5,312	5,394	5,337	5,396	5,312

Table 2.2-27 Forecast Demand Less Actual Winter Demand (MW)

	Actual less Forecast (MW)					Percent Difference				
	2023 Forecast	2022 Forecast	2021 Forecast	2020 Forecast	2019 Forecast	2023 Forecast	2022 Forecast	2021 Forecast	2020 Forecast	2019 Forecast
2019					277					5.2%
2020				178	116				3.3%	2.2%
2021			133	246	164			2.5%	4.6%	3.1%
2022		-213	-169	-157	-237		-4.0%	-3.2%	-2.9%	-4.5%
2023	-71	11	-46	13	-70	-1.3%	0.2%	-0.9%	0.2%	-1.3%

Figure 2.2-15 Forecast Comparison to Actual Native Energy

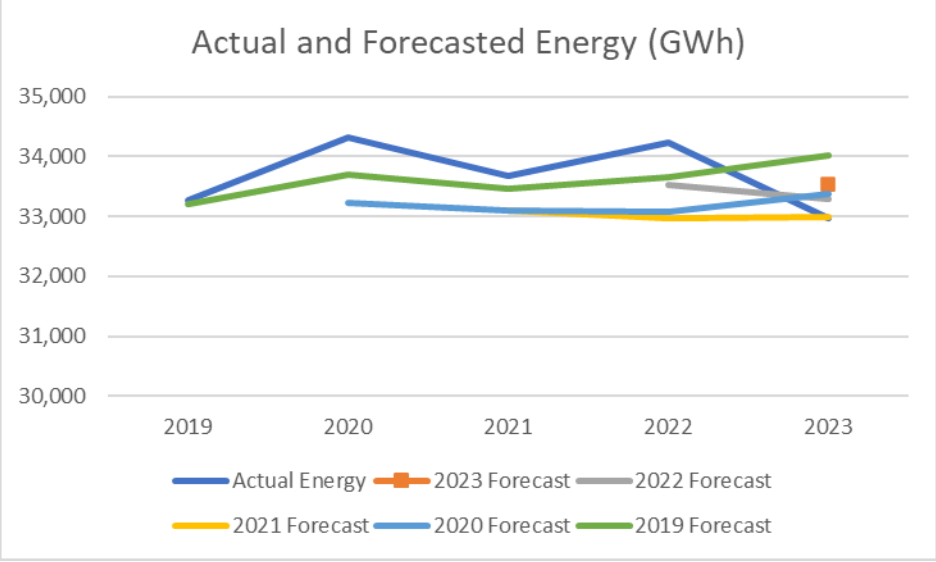


Figure 2.2-16 Forecast Comparison to Actual Summer Native Peak Demand

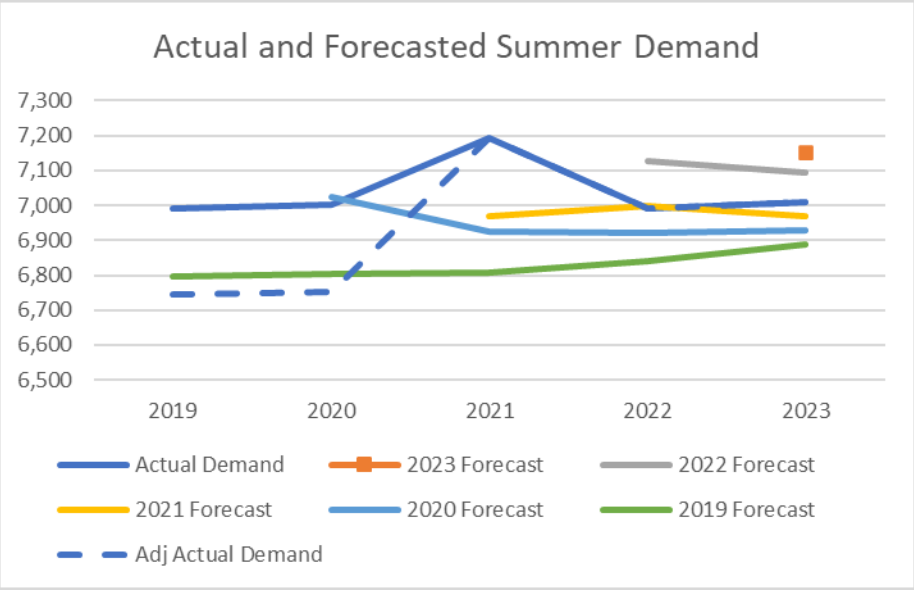
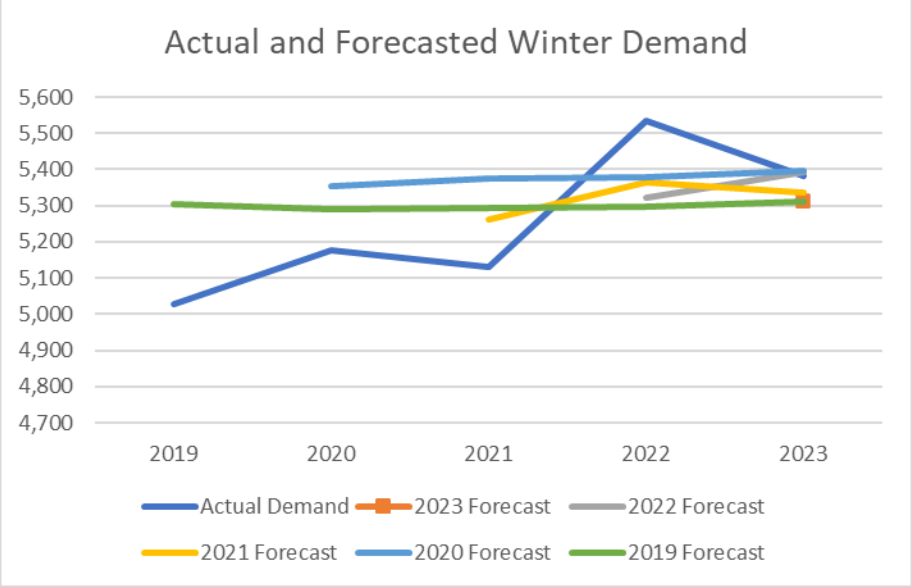


Figure 2.2-17 Forecast Comparison to Actual Winter Native Peak Demand



Description and Justification

Tables 2.2-28 through 2.2-44 show the parameters associated with Public Service's econometric forecasting models.

Table 2.2-28 Number of Residential Electric Customers

REGRESSION PERIOD: Jan 2009 through Dec 2023				
NUMBER OF OBSERVATIONS: 167				
LINEAR LEAST SQUARES MODEL WITH ARMA ERRORS				
Residential Customers = C1*Population + C2*Cumulative Occupied Multi-Family Units				
ARMA (1,0) process applied to errors				
Variable	Coefficient	StdErr	T-Stat	P-Value
C1	332.356	3.050	108.980	0.00%
C2	0.594	0.111	5.346	0.00%
AR(1)	0.976	0.008	127.273	0.00%
SAR(1)	0.591	0.063	9.419	0.00%
MA(1)	0.230	0.075	3.075	0.25%

Table 2.2-29 Residential Electric Customers – Regression Statistics

Regression Statistics	
Iterations	37
Adjusted Observations	167
Deg. of Freedom for Error	162
R-Squared	1.000
Adjusted R-Squared	1.000
AIC	12.424
BIC	12.517
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-1,269.35
Model Sum of Squares	645,616,229,977.56
Sum of Squared Errors	39,109,928.35
Mean Squared Error	241,419.31
Std. Error of Regression	491.34
Mean Abs. Dev. (MAD)	388.57
Mean Abs. % Err. (MAPE)	0.03%
Durbin-Watson Statistic	1.873
Durbin-H Statistic	#NA
Ljung-Box Statistic	38.99
Prob (Ljung-Box)	0.0274
Frequency of historical data is monthly	

Table 2.2-30 Residential Electric Customers – Definitions and Sources

Variable Name	Definition/Source
Residential Customers	Public Service residential electric customers / Public Service
Population	Population for the following metro cities: Denver, Aurora, Lakewood, Greeley, Boulder and Grand Junction.

Table 2.2-31 Residential Electric Sales per Customer

SAMPLE PERIOD: Jan 2009 through Dec 2023				
NUMBER OF OBSERVATIONS: 179				
LINEAR LEAST SQUARES MODEL WITH ARMA ERRORS				
AvgRes_Use = C1*Heating + C2*Cooling + C3*Other + C4*Jan + C5*Feb + C6*Mar + C7*Jun + C8*Jul + C9*Aug + C10*Sep + C11*Dec + C12*PostCOVID_Cooling + C13* COVID+Lockdown + C14*Aug11 + C15*Aug12 + C16*Aug23 + C17*Dec23				
ARMA(1,0) process applied to errors				
Variable	Coefficient	StdErr	T-Stat	P-Value
C1	0.949	0.073	12.999	0.00%
C2	0.860	0.049	17.578	0.00%
C3	0.956	0.035	27.317	0.00%
C4	89.378	8.604	10.387	0.00%
C5	24.494	8.076	3.033	0.28%
C6	23.515	7.093	3.315	0.11%
C7	58.249	5.615	10.374	0.00%
C8	110.001	8.898	12.362	0.00%
C9	71.513	12.064	5.928	0.00%
C10	19.684	9.715	2.026	4.44%
C11	44.767	6.426	6.967	0.00%
C12	0.086	0.029	2.955	0.36%
C13	40.147	12.124	3.311	0.12%
C14	62.999	18.578	3.391	0.09%
C15	-50.748	19.086	-2.659	0.86%
C16	69.965	19.145	3.654	0.04%
C17	-37.977	19.507	-1.947	5.33%
AR(1)	0.976	0.015	64.255	0.00%
MA(1)	-0.745	0.062	-11.957	0.00%

Table 2.2-32 Residential Electric Sales per Customer – Regression Statistics

Regression Statistics	
Iterations	22
Adjusted Observations	179
Deg. of Freedom for Error	160
R-Squared	0.971
Adjusted R-Squared	0.968
AIC	5.958
BIC	6.296
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-768.21
Model Sum of Squares	1,885,206.20
Sum of Squared Errors	55,988.25
Mean Squared Error	349.93
Std. Error of Regression	18.71
Mean Abs. Dev. (MAD)	14.13
Mean Abs. % Err. (MAPE)	2.21%
Durbin-Watson Statistic	1.937
Durbin-H Statistic	#NA
Ljung-Box Statistic	49.82
Prob (Ljung-Box)	0.0015
Frequency of historical data is monthly	

Table 2.2-33 Residential Electric Sales per Customer – Definitions and Sources

Variable Name	Definition/Source
AvgRes_Use	Residential kWh sales per customer/Public Service
Cooling	CoolIndex * CoolUse CoolUse = Price^(-0.15)) * (Income per Household^0.2) * (Household Size^0.25) * Cooling Degree Days/Public Service, IHS Markit.
Heating	HeatIndex * HeatUse HeatUse = Price^(-0.15)) * (Income per Household^0.2) * (Household Size^0.25) * Heating Degree Days/Public Service, IHS Markit.
Other	OtherEqpIndex * OtherUse OtherUse = Price^(-0.15)) * (Income per Household^0.1) * (Household Size^0.46) * Cooling Degree Days/Public Service, IHS Markit.
Jan-Dec	Binary variable for each month except April, May, Oct, & Nov
PostCOVID_XCool	XCool*Year >= 2021
COVID_Lockdown	Binary variable = 1 beginning May 2020 and ending July 2020
Aug11	Binary variable = 0 for all months except August 2011 = 1
Aug12	Binary variable = 0 for all months except August 2012 =1
Aug23	Binary variable = 0 for all months except August 2023 = 1
Dec23	Binary variable = 0 for all months except December 2023 =1

Table 2.2-34 Commercial & Industrial Electric Sales

SAMPLE PERIOD: Jan 2009 through Dec 2023				
NUMBER OF OBSERVATIONS: 180				
LINEAR LEAST SQUARES MODEL WITH ARMA ERRORS				
MWh = C1*CI_Custs + C2*XHeat + C3*XCool + C4*XOther + C5*PostCOVID_XCool + C6*COVID_XHeat + C7*COVID_Outliers + C8*Feb + C9*Apr + C10*May + C11*Nov				
ARMA(1,0) process applied to errors				
Variable	Coefficient	StdErr	T-Stat	P-Value
C1	4.420	0.262	16.858	0.00%
C2	0.693	0.079	8.745	0.00%
C3	1.138	0.073	15.609	0.00%
C4	0.487	0.031	15.960	0.00%
C5	-465554.267	107602.262	-4.327	0.00%
C6	-85135.744	37067.140	-2.297	2.29%
C7	-123206.059	24622.641	-5.004	0.00%
C8	-73652.717	13916.367	-5.293	0.00%
C9	-82230.190	13001.089	-6.325	0.00%
C10	-57180.520	13596.748	-4.205	0.00%
C11	-66150.482	14113.730	-4.687	0.00%
SMA(1)	0.277	0.080	3.466	0.07%

Table 2.2-35 Commercial & Industrial Electric Sales – Regression Statistics

Regression Statistics	
Iterations	14
Adjusted Observations	180
Deg. of Freedom for Error	168
R-Squared	0.905
Adjusted R-Squared	0.899
AIC	21.019
BIC	21.232
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-2,135.09
Model Sum of Squares	2,020,737,904,237.43
Sum of Squared Errors	211,677,778,329.07
Mean Squared Error	1,259,986,775.77
Std. Error of Regression	35,496.29
Mean Abs. Dev. (MAD)	27,416.63
Mean Abs. % Err. (MAPE)	1.97%
Durbin-Watson Statistic	1.647
Durbin-H Statistic	#NA
Ljung-Box Statistic	89.78
Prob (Ljung-Box)	0.0000
Frequency of historical data is monthly	

Table 2.2-36 Commercial & Industrial Electric Sales – Definitions and Sources

Variable Name	Definition/Source
MWh	Commercial/Industrial Electric Sales/Public Service
CI Custs	Historical and forecasted Commercial/Industrial customers/Public Service
Cooling	CoolIndex * CoolUse = Price^(-0.15)) * (Com.Output Index^0.25) * Cooling Degree Days/Public Service, IHS Markit.
Heating	HeatIndex * HeatUse = Price^(-0.15)) * (Com.Output Index^0.25) * Heating Degree Days/Public Service, IHS Markit.
Other	OtherEqpIndex * OtherUse = Price^(-0.15)) * (Com.Output Index^0.25) * Heating Degree Days/Public Service, IHS Markit.
PostCOVID_XCool	CoolUse*Year >= 2020
COVID_XHeat	HeatUse*(Year = 2020 or Year = 2021 or (Year = 2020 and Month < 3))
COVID_Outliers	Binary variable = 1 beginning May 2020 and ending June 2020
Feb, Apr, May and Nov	Binary variable for each month February, April, May and November

Table 2.2-37 Electric Street and Highway Lighting Sales – Regression Statistics

Regression Statistics	
Iterations	11
Adjusted Observations	179
Deg. of Freedom for Error	158
R-Squared	0.990
Adjusted R-Squared	0.989
AIC	11.497
BIC	11.871
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-1,262.01
Model Sum of Squares	1,420,821,510.12
Sum of Squared Errors	13,938,517.51
Mean Squared Error	88,218.47
Std. Error of Regression	297.02
Mean Abs. Dev. (MAD)	158.69
Mean Abs. % Err. (MAPE)	1.14%
Durbin-Watson Statistic	2.429
Durbin-H Statistic	#NA
Ljung-Box Statistic	28.62
Prob (Ljung-Box)	0.2347
Frequency of historical data is monthly	

Table 2.2-38 Electric Street and Highway Lighting Sales – Definitions and Sources

Variable Name	Definition/Source
Streetlight	Public Service Street and Highway Lighting Electric Sales/Public Service
Intensity_Light	Lighting Intensity
Population	Population for the following metro cities: Denver, Aurora, Lakewood, Greeley, Boulder and Grand Junction.
Jan-Dec	Binary variables for each month except December
Jan2013	Binary variable = 0 for all months except January 2013 = 1
Feb2013	Binary variable = 0 for all months except February 2013 = 1
Feb2016	Binary variable = 0 for all months except February 2016 = 1
Nov2019	Binary variable = 0 for all months except November 2019 = 1
Dec2019	Binary variable = 0 for all months except December 2019 =1
Jan2020	Binary variable = 0 for all months except January 2020 =1
Feb2020	Binary variable = 0 for all months except February 2020 =1

Table 2.2-39 Residential Contribution to System Peak Demand

SAMPLE PERIOD: Jan 2009 through Dec 2023				
NUMBER OF OBSERVATIONS: 168				
LINEAR LEAST SQUARES MODEL				
Res_Coincident = C1*Res_Native_Adj_Seasonal + C2*Jan_HDD_Index_Cust + C3*Feb_HDD_Index_Cust + C4*May_CDD_Index_Cust + C5*Jun_CDD_Index_Cust + C6*Jul_CDD_Index_Cust + C7*Aug_CDD_Index_Cust + C8*Sep_CDD_Index_Cust + C9*Nov_HDD_Index_Cust + C10*Dec_HDD_Index_Cust + C11*Hour_15 + C12*Hour_16 + C13*Hour_17 + C14*Hour_18 + C15*Hour_19 +C16*Sep2014 + C17*Apr2016 + C18*May2016 + C19*Jul2023				
ARMA(1,0,0) x (0,0,0) process applied to errors				
Variable	**Coefficient**	**StdErr**	**T-Stat**	**P-Value**
C1	1.882	0.041	46.404	0.00%
C2	2.726	0.371	7.355	0.00%
C3	1.788	0.346	5.164	0.00%
C4	11.920	4.450	2.679	0.82%
C5	46.273	1.825	25.359	0.00%
C6	48.695	1.802	27.024	0.00%
C7	51.830	2.050	25.285	0.00%
C8	50.662	2.357	21.497	0.00%
C9	1.350	0.486	2.779	0.62%
C10	3.380	0.387	8.725	0.00%
C11	0.000	0.000	0.000	100.00%
C12	-394.137	73.562	-5.358	0.00%
C13	-235.328	46.776	-5.031	0.00%
C14	100.962	45.624	2.213	2.84%
C15	247.836	41.242	6.009	0.00%
C16	788.954	142.883	5.522	0.00%
C17	-445.504	142.249	-3.132	0.21%
C18	-363.391	142.296	-2.554	1.17%
C19	431.943	145.169	2.975	0.34%
SAR(1)	-0.135	0.079	-1.701	9.11%

Table 2.2-40 Residential Contribution to System Peak Demand – Regression Statistics

Regression Statistics	
Iterations	12
Adjusted Observations	168
Deg. of Freedom for Error	148
R-Squared	0.937
Adjusted R-Squared	0.928
AIC	10.053
BIC	10.425
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-1,062.82
Model Sum of Squares	45,378,343.26
Sum of Squared Errors	3,074,715.50
Mean Squared Error	20,775.10
Std. Error of Regression	144.14
Mean Abs. Dev. (MAD)	109.64
Mean Abs. % Err. (MAPE)	5.76%
Durbin-Watson Statistic	2.086
Durbin-H Statistic	#NA
Ljung-Box Statistic	26.64
Prob (Ljung-Box)	0.3217
Frequency of historical data is monthly	

Table 2.2-41 Residential Contribution to System Peak Demand – Definitions and Sources

Variable Name	Definition/Source
Res_Conincident	Residential class contribution to system peak (MW) / Public Service
Res_Native_Adj_Seasonal	Seasonal average of actual and forecast Residential kWh sales / Public Service (calculated internally in the sales model)
CDD_Index_Cust	Max Cooling Degree Days (base 65) * Residential Cooling Index * Customer counts for the months of May, June, July, August, and September
HDD_Index_Cust	Max Heating Degree Days (base 65) * Residential Heating Index * Customer counts for the months of January, February, November, and December
Peak_Hr_Bin	Binary variable = 0 for all months except for hours_15, hour_16, hour_17, hour_18 and hour_19 = 1 if the peak occurred in the designated hour
Sep2014	Binary variable = 0 for all months except September 2014 = 1
Apr2016	Binary variable = 0 for all months except April 2016 = 1
May2016	Binary variable = 0 for all months except May 2016 = 1
Jul2023	Binary variable = 0 for all months except July 2023 = 1

Table 2.2-4242 Non-Residential Contribution to System Peak Demand

SAMPLE PERIOD: Jan 2002 through Dec 2023				
NUMBER OF OBSERVATIONS: 264				
LINEAR LEAST SQUARES MODEL				
NonRes_Coincident = C1 + C2*NonRes_Native_Adj + C3*Jun_CDD_Index_Cust + C4*Jul_CDD_Index_Cust + C5*Aug_CDD_Index_Cust + C6*Sep_CDD_Index_Cust + C7*Jan + C8*Feb + C9*Mar + C10*Apr + C11*Oct + C12*Nov + C13*Dec + C14*Hour_18 + C15*Apr2006 + C16*Apr2007 + C17*Sep2008 + C18*Apr2012 + C19*Jan2014 + C20*May2015 + C21*May2017 + C22*Sep2020 + C23*May2023				
Variable	**Coefficient**	**StdErr**	**T-Stat**	**P-Value**
C1	2042.047	326.814	6.248	0.00%
C2	0.001	0.000	2.956	0.34%
C3	0.133	0.023	5.853	0.00%
C4	0.188	0.022	8.681	0.00%
C5	0.183	0.025	7.415	0.00%
C6	0.108	0.035	3.076	0.23%
C7	-403.536	50.064	-8.060	0.00%
C8	-441.850	50.199	-8.802	0.00%
C9	-589.325	50.433	-11.685	0.00%
C10	-639.029	47.685	-13.401	0.00%
C11	-409.993	48.435	-8.465	0.00%
C12	-284.757	50.674	-5.619	0.00%
C13	-259.268	50.620	-5.122	0.00%
C14	-149.418	28.107	-5.316	0.00%
C15	572.669	164.162	3.488	0.06%
C16	748.432	164.008	4.563	0.00%
C17	-734.880	162.874	-4.512	0.00%
C18	650.216	164.303	3.957	0.01%
C19	-465.282	165.048	-2.819	0.52%
C20	-606.438	163.491	-3.709	0.03%
C21	-394.482	164.869	-2.393	1.75%
C22	-620.043	171.007	-3.626	0.04%
C23	-635.144	164.717	-3.856	0.02%
MA(1)	0.254	0.064	3.952	0.01%

Table 2.2-43 Non-Residential Contribution to System Peak Demand – Regression Statistics

Regression Statistics	
Iterations	10
Adjusted Observations	264
Deg. of Freedom for Error	240
R-Squared	0.842
Adjusted R-Squared	0.826
AIC	10.300
BIC	10.625
F-Statistic	55.466
Prob (F-Statistic)	0.0000
Log-Likelihood	-1,710.25
Model Sum of Squares	34,800,475.99
Sum of Squared Errors	6,546,965.58
Mean Squared Error	27,279.02
Std. Error of Regression	165.16
Mean Abs. Dev. (MAD)	117.72
Mean Abs. % Err. (MAPE)	4.28%
Durbin-Watson Statistic	1.963
Durbin-H Statistic	#NA
Ljung-Box Statistic	41.60
Prob (Ljung-Box)	0.0143
Frequency of historical data is monthly	

Table 2.2-44 Non-Residential Contribution to System Peak Demand – Definitions and Sources

Variable Name	Definition/Source
NonRes_Conincident	Commercial and industrial class contribution to system peak (MW) / Public Service
NonRes_SalesTrend	12 month moving average of actual and forecast Non-Residential kWh sales / Public Service (calculated internally in the sales model)
CDD_Index_Cust	Max Cooling Degree Days (base 65) * Residential Cooling Index * Customer counts for the months of June, July, August and September
Jan-Dec	Binary variables for each month except May, June, July, August, September, and October
Hour_18	Binary variable = 0 for all months except for hour_18 = 1 if the peak occurred in the designated hour
Apr2006	Binary variable = 0 for all months except April 2006 = 1
Apr2007	Binary variable = 0 for all months except April 2007 = 1
Sep2008	Binary variable = 0 for all months except September 2008 =1
Apr2012	Binary variable = 0 for all months except April 2012 =1
Jan2014	Binary variable = 0 for all months except January 2014 =1
May2015	Binary variable = 0 for all months except May 2015 =1
May2017	Binary variable = 0 for all months except May 2017 =1
Sep2020	Binary variable = 0 for all months except September 2020 =1
May2023	Binary variable = 0 for all months except May 2023 =1

2.3 TYPICAL DAY LOAD PATTERNS

In this Section, the Company provides typical day load patterns on a system-wide basis for each major customer class (by voltage level), provided for peak day, average day, and representative off-peak days for each calendar month as required by Rule 3606(a)(VI).

The following monthly class load shapes are developed from Company load research data for the year 2022. The following statistics were used for each requirement:

Requirement	Statistic
Peak Day	System Peak Day
Average Day	Average Weekday Excluding Holidays
Representative Off-Peak Day	Average Weekends and Holidays

The residential and commercial and industrial profiles were developed from aggregated load research classes. These profiles were calculated using the population weighted average load of all the rate classes in each group.

Appendix A contains Figures 2.3-1 through 2.3-60 with tables and graphs for each of the load patterns described above.

Residential	Figures 2.3-1 through 2.3-12
Commercial & Industrial (Secondary)	Figures 2.3-13 through 2.3-24
Commercial & Industrial (Primary)	Figures 2.3-25 through 2.3-36
Commercial & Industrial (Transmission)	Figures 2.3-37 through 2.3-48
Wholesale	Figures 2.3-49 through 2.3-60

Please note that the wholesale data provided for two customers who are part owners in Comanche 3 contains their total load (what is served by both Public Service and Comanche 3). Public Service is required to serve their total load in the event that Comanche 3 is not online. In addition, the WAPA allocations for the wholesale data are not subtracted from the total load provided because hourly WAPA data is not available.

2.4 EVALUATION OF EXISTING RESOURCES

This Section includes existing resources information required by Rule 3607. Specifically, Rule 3607(a) requires the Company to describe its existing resources, all utility-owned generation facilities and energy storage systems for which the utility has obtained a Certificate of Public Convenience and Necessity ("CPCN") from the Commission pursuant to § 40-5-101, C.R.S. at the time the plan is filed, and existing or future purchases from other utilities or non-utilities pursuant to agreements effective at the time the plan is filed. The Company notes that of the resources included as part of the Alternative Portfolio approved in Phase II of the 2021 ERP & CEP, as of the time of filing the JTS, the Company has obtained a CPCN for the Arroyo 2 solar project and the Rocky Mountain solar plus storage project (Proceeding No. 24A-0140E) as discussed below, and the Company is continuing further due diligence and contract negotiations regarding acquisition of the PPA resources included in the Alternative Portfolio. Accordingly, Rocky Mountain and Arroyo 2 are the only resources as part of the Alternative Portfolio approved in Phase II of the 2021 ERP & CEP reflected in the existing resources information below.

Company-Owned Resources

Table 2.4-1 on the following page lists the names and locations (by county) of generation facilities and energy storage systems owned by Public Service as required by Rule 3607(a)(I).

Table 2.4-1 Name and Location of Public Service-Owned Generation Facilities and Energy Storage Systems

Facility Name	Unit	Location
Alamosa	1,2	Alamosa County
Ames	1	San Miguel County
Arroyo 2	2	Pueblo County
Blue Spruce	1,2	Arapahoe County
Cabin Creek	A,B	Clear Creek County
Cherokee	4,5,6,7	Adams County
Cheyenne Ridge	-	Cheyenne and Kit Carson Counties
Comanche	2,3	Pueblo County
Craig	1,2	Moffat County
Fruita	1	Mesa County
Form Energy		Pueblo County
Ft. Lupton	1,2	Weld County
Ft. St. Vrain	1,2,3,4,5,6	Weld County
Hayden	1,2	Routt County
Manchief	11,12	Morgan County

Pawnee		Morgan County
Pawnee	1	Morgan County
Pena Station	1	Denver County
Rocky Mountain		Pueblo County
Rocky Mtn Energy Center	1,2,3	Weld County
Rush Creek I	-	Elbert County
Rush Creek II	-	Lincoln County
Salida	2	Chaffee County
Shoshone	A,B	Garfield County
Tacoma	1,2	La Plata County
Valmont	6,7,8	Boulder County

Table 2.4-2 below provides the following information for Public Service-owned generation facilities and energy storage systems as required by Rule 3607(a)(II), (III), and (V):

- Gross Maximum Capacity
- Summer Net Dependable Capacity
- Accredited Capacity
- Fuel Type
- Heat Rate
- Estimated In-Service Year
- Estimated Remaining Useful Life (i.e., Estimated Retirement Year)

Table 2.4-2 Public Service-Owned Generation Facilities and Energy Storage Systems

Facility Name & Unit	Gross Maximum Capacity (MW)	Summer Net Dependable Capacity (MW)	Accredited Capacity (MW) (1)	Fuel Type	Heat Rate (MMbtu/kWh) (2)	Estimated In-Service Year (3)	Estimated Retirement Year (3)
Alamosa 1	17	13	12	Gas	14.98	In-Service	2026
Alamosa 2	18	14	13	Gas	16.04	In-Service	2026
Ames	3	3	1	Hydro	n/a	In-Service	2050
Arroyo 2	335	335	70	Solar	n/a	2027	2058
Blue Spruce 1	146	130	115	Gas	10.54	In-Service	2050
Blue Spruce 2	150	134	119	Gas	10.43	In-Service	2050
Cabin Creek A	170	170	98	Storage	n/a	In-Service	2054
Cabin Creek B	170	170	98	Storage	n/a	In-Service	2054
Cherokee 4	335	310	228	Gas	10.63	In-Service	2027
Cherokee 5	182	168	145	Gas	10.00	In-Service	2055
Cherokee 6	182	168	145	Gas	10.00	In-Service	2055
Cherokee 7	248	240	207	Gas	6.79	In-Service	2055

Cheyenne Ridge	498	498	106	Wind	n/a	In-Service	2045
Comanche 2	363	330	296	Coal	10.34	In-Service	2025
Comanche 3 (4)	536	500	412	Coal	9.49	In-Service	2030
Craig 1 (5)	43	42	38	Coal	10.37	In-Service	2025
Craig 2 (5)	42	40	36	Coal	10.22	In-Service	2028
Fruita 1	18	14	13	Gas	15.30	In-Service	2026
Form Energy	10	10	10	Storage	n/a	2026	2045
Ft. Lupton 1	50	44	23	Gas	12.67	In-Service	2025
Ft. Lupton 2	50	44	25	Gas	12.67	In-Service	2025
Ft. St. Vrain 1	322	308	275	Gas	7.72	In-Service	2041
Ft. St. Vrain 2	177	150	134	Gas	10.84	In-Service	2041
Ft. St. Vrain 3	175	142	127	Gas	10.84	In-Service	2041
Ft. St. Vrain 4	173	142	127	Gas	10.84	In-Service	2041
Ft. St. Vrain 5	157	140	119	Gas	10.23	In-Service	2049
Ft. St. Vrain 6	157	140	121	Gas	10.35	In-Service	2049
Hayden 1 (6)	149	135	120	Coal	10.31	In-Service	2028
Hayden 2 (7)	107	98	90	Coal	10.01	In-Service	2027
Manchief 11	139	125	94	Gas	10.11	In-Service	2040
Manchief 12	139	125	94	Gas	10.11	In-Service	2040
Pawnee 1 (8)	536	505	462	Coal/Gas	10.65	In-Service	2025/2041
Pena Station	1	1	0	Solar	n/a	In-Service	2036
Rocky Mountain - Solar	325	325	68	Solar	n/a	2026	2060
Rocky Mountain - Storage	200	200	115	Storage	n/a	2026	2060
Rocky Mtn. Energy Center 1	170	146	131	Gas	10.69	In-Service	2049
Rocky Mtn. Energy Center 2	170	146	131	Gas	10.69	In-Service	2049
Rocky Mtn. Energy Center 3	317	300	269	Gas	7.51	In-Service	2049
Rush Creek I	400	400	85	Wind	n/a	In-Service	2043
Rush Creek II	200	200	42	Wind	n/a	In-Service	2043
Salida 2	0.6	0.6	0	Hydro	n/a	In-Service	2027
Shoshone A	8	8	4	Hydro	n/a	In-Service	2058
Shoshone B	8	8	4	Hydro	n/a	In-Service	2058
Tacoma 1	2	2	1	Hydro	n/a	In-Service	2050
Tacoma 2	2	2	1	Hydro	n/a	In-Service	2050
Valmont 6	51	43	28	Gas	12.80	In-Service	2026
Valmont 7	40	36	26	Gas	9.92	In-Service	2038
Valmont 8	42	40	24	Gas	9.84	In-Service	2038

(1) Accredited capacity values incorporate resource-specific Effective Load Carrying Capabilities (ELCC) and represent 2028 values to align with the first year of the RAP. If a unit retires before 2028, the accredited capacity value represents the unit's final year of operation.
(2) Unit heat rates are considered confidential information, and therefore the information provided is the average of summer, winter, and spring/fall heat rates.
(3) In-service year is the first year the unit is available for the summer peak and retirement year is the last summer peak the unit is available.
(4) PSCo capacity only (66.67% of total unit).
(5) PSCo capacity only (9.72% of total unit).
(6) PSCo capacity only (75.5% of total unit).
(7) PSCo capacity only (37.4% of total unit).
(8) Pawnee will convert from coal to natural gas combustion in 2026.

Table 2.4-3 below shows the projected annual capacity factor of Public Service-owned generation facilities and energy storage systems over the RAP as required by Rule 3607(a)(III).

Table 2.4-3 Projected Capacity Factors

Base Plan (SCC) Projected Capacity Factors							
Facility Name & Unit	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
COAL UNITS							
Comanche 2	85%						
Comanche 3	60%	55%	50%	44%	33%	32%	
Craig 1	55%						
Craig 2	57%	57%	73%	44%			
Hayden 1	72%	69%	73%	55%			
Hayden 2	71%	62%	76%				
Pawnee - Coal	64%						
GAS COMBINED CYCLE UNITS							
Cherokee	50%	44%	43%	28%	29%	28%	24%
Fort St. Vrain	33%	24%	22%	14%	20%	19%	16%
Rocky Mountain Energy Center	37%	35%	32%	13%	19%	20%	15%
GAS COMBUSTION TURBINE UNITS							
Alamosa 1	0%	0%					
Alamosa 2	0%	0%					
Blue Spruce 1	7%	4%	4%	1%	1%	2%	1%
Blue Spruce 2	11%	6%	5%	2%	5%	7%	4%
Fort Lupton 1	0%						
Fort Lupton 2	0%						
Fort St Vrain 5	10%	5%	5%	2%	2%	5%	3%
Fort St Vrain 6	7%	3%	3%	2%	1%	2%	1%
Fruita	0%	0%					
Manchief	5%	2%	1%	0%		1%	0%
Valmont 6	0%	0%					
Valmont 7-8	1%	0%	0%	0%	0%	0%	0%
GAS STEAM UNITS							
Cherokee 4	30%	30%	30%				
Pawnee - Gas		14%	11%	11%	11%	11%	9%
HYDROELECTRIC UNITS							
Ames	29%	29%	28%	29%	29%	29%	29%
Salida	33%	33%	33%				
Shoshone	68%	68%	68%	68%	68%	68%	68%
Tacoma	24%	24%	24%	24%	24%	24%	24%
PUMPED STORAGE UNITS							
Cabin Creek	15%	14%	14%	11%	15%	15%	12%
WIND UNITS							
Cheyenne Ridge	44%	44%	44%	44%	44%	23%	22%
Rush Creek	42%	42%	42%	27%	23%	20%	19%

Table 2.4-4 shows the projected annual availability factor of Public Service-owned generation facilities and energy storage systems over the RAP as required by Rule 3607(a)(III).

Table 2.4-4 Projected Availability Factors

Base Plan (SCC) Projected Availability Factors							
Facility Name & Unit	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
COAL UNITS							
Comanche 2	93%						
Comanche 3	78%	78%	73%	79%	79%	73%	
Craig 1	92%						
Craig 2	92%	92%	92%	94%			
Hayden 1	92%	92%	88%	84%			
Hayden 2	95%	91%	95%				
Pawnee - Coal	70%						
GAS COMBINED CYCLE UNITS							
Cherokee	85%	86%	84%	86%	85%	86%	84%
Fort St. Vrain	91%	89%	87%	87%	91%	89%	87%
Rocky Mountain Energy Center	75%	93%	91%	76%	93%	91%	76%
GAS COMBUSTION TURBINE UNITS							
Alamosa 1	92%	92%					
Alamosa 2	95%	95%					
Blue Spruce 1	89%	80%	89%	89%	89%	80%	89%
Blue Spruce 2	90%	90%	90%	81%	90%	90%	90%
Fort Lupton 1	54%						
Fort Lupton 2	59%						
Fort St Vrain 5	88%	88%	88%	77%	88%	88%	88%
Fort St Vrain 6	90%	90%	90%	79%	90%	90%	90%
Fruita	86%	86%					
Manchief	74%	74%	77%	77%	74%	74%	77%
Valmont 6	69%	69%					
Valmont 7-8	69%	69%	69%	69%	69%	69%	69%
GAS STEAM UNITS							
Cherokee 4	61%	62%	61%				
Pawnee - Gas		93%	93%	81%	93%	93%	81%
HYDROELECTRIC UNITS							
Ames	29%	29%	29%	29%	29%	29%	29%
Salida	33%	33%	33%				
Shoshone	68%	68%	68%	68%	68%	68%	68%
Tacoma	24%	24%	24%	24%	24%	24%	24%
PUMPED STORAGE UNITS							
Cabin Creek	83%	84%	81%	82%	84%	84%	86%
WIND UNITS							
Cheyenne Ridge	44%	44%	44%	44%	44%	44%	44%
Rush Creek	42%	42%	42%	42%	42%	42%	42%

In-Service Date for Facilities Granted a CPCN

Rule 3607(a)(IV) requires the Company to provide estimated in-service dates for utility-owned generation facilities for which a CPCN has been granted but which are not in service at the time the plan under consideration is filed.

On March 25, 2024, Public Service filed a single Application for two CPCNs to construct, own, and operate two generation resources, including: (1) the Rocky Mountain 325 MW solar plus 200 MW storage project and, (2) the 335 MW Arroyo 2 solar project (collectively,

the “Facilities”), both located in Pueblo County. The Facilities were included as two of the Company-owned generation resources comprising the Alternative Portfolio approved by the Commission in Phase II of the Company’s 2021 ERP & CEP in Proceeding No. 21A-0141E. On June 7, 2024, Public Service filed an Unopposed Comprehensive Settlement Agreement, which was approved without modification by Decision No. C24-0525 (issued July 23, 2024). The estimated in-service date for the Rocky Mountain and Arroyo 2 projects are December 2025 and October 2026, respectively.

The Company anticipates filing CPCNs for remaining Company-owned projects included in the approved Alternative Portfolio and backup bids, as necessary, in late 2024 and/or early 2025. There are no other utility-owned generation facilities for which a CPCN has been granted but is not in service at the time of filing this 2024 JTS.

Purchased Power

Public Service buys a significant amount of firm capacity and energy through power purchase agreements (“PPAs”) with various agreement term lengths and fuel resource types. These PPAs contain provisions that detail the amount and type of capacity available to Public Service. Some are “unit contingent,” meaning that the delivered capacity is contingent upon the availability of certain generating facilities. If one of these facilities is not available for operation, the supplying counterparty can reduce the amount of capacity provided to Public Service.

Table 2.4-5 below summarizes the following for all PPAs to which Public Service currently purchases firm capacity as required by Rule 3607(a)(VI):

- Resource Type
- Summer Net Dependable Capacity
- Accredited Capacity
- PPA Summer Expiration Year

Table 2.4-5 PPA Fuel Type, Summer Net Dependable Capacity, Accredited Capacity, and Duration

Power Purchase Agreement	Summer Net Dependable Capacity (MW)	Accredited Capacity (MW) (1)	Fuel Type	Expires (2)
Arapahoe 5,6,7	118	108	Gas	2025
Bighorn	240	49	Solar	2041
Bronco Plains	299	64	Wind	2045
Brush 2	68	64	Gas	2025
Brush 4D	131	121	Gas	2026
Cedar Creek	301	48	Wind	2027
Cedar Creek II	251	53	Wind	2035
Cedar Point	252	53	Wind	2031
City of Boulder - Betasso	3	2	Hydro	2027
City of Boulder - Lakewood	3	2	Hydro	2027
City of Boulder - Silver Lake	3	2	Hydro	2027
Colorado Green	162	34	Wind	2038
Comanche	120	24	Solar	2041
DWB - Dillon	2	1	Hydro	2026
DWB - Foothills	2	1	Hydro	2026
DWB - Gross Reservoir	8	4	Hydro	2026
DWB - Hillcrest	2	1	Hydro	2026
DWB - Roberts Tunnel	6	3	Hydro	2026
DWB - Strontia	1	1	Hydro	2026
Fountain Valley 1-6	236	213	Gas	2031
Golden West	249	53	Wind	2040
Greater Sandhill	16	3	Solar	2030
Hooper	50	10	Solar	2036
Limon I	200	42	Wind	2037
Limon II	200	42	Wind	2037
Limon III	201	43	Wind	2039
Logan	201	32	Wind	2027
Mountain Breeze	172	36	Wind	2045
Neptune - Solar	325	67	Solar	2047
Neptune - Storage	125	72	Storage	2047
Northern Colorado I	152	32	Wind	2033
Northern Colorado II	23	5	Wind	2029
Peetz Table	200	42	Wind	2032

Plains End I	112	105	Gas	2027
Plains End II	108	101	Gas	2027
Redlands Water & Power	1	1	Hydro	2024
San Luis	30	6	Solar	2031
Spindle Hill	272	252	Gas	2026
Spring Canyon	60	9	Wind	2025
STS (Mt. Elbert)	3	0	Hydro	2026
Sun Mountain	200	41	Solar	2037
SunE Alamosa I	7	2	Solar	2027
Thunder Wolf - Solar	248	51	Solar	2047
Thunder Wolf - Storage	100	57	Storage	2047
Titan	50	10	Solar	2038
Twin Buttes	75	12	Wind	2026
Waste Management	3	3	Biomass	2023

(1) Accredited capacity values incorporate resource-specific Effective Load Carrying Capabilities ("ELCC") and represent 2028 values to align with the first year of the RAP. If a unit retires before 2028, the accredited capacity value represents the unit's final year of operation.
(2) Final year in which capacity is available to serve peak summer load.

Table 2.4-6 provides a description of contract provisions that allow for modification of the amount of capacity or energy from generation facilities or energy storage systems for current Public Service PPAs as required by Rule 3607(a)(VI).

Table 2.4-6 PPA Contract Modification Terms

Power Purchase Agreement	Contract Modifications Terms
Arapahoe 5,6,7	Seller shall offer any Excess Energy and/or Excess Capacity providing Company a Commercially Reasonable period of time of not less than 10 Business Days to respond to the offer.
Cedar Creek	PSCo shall pay Seller at an energy payment rate equal to 50% or the Renewable Energy Payment Rate for all energy in excess of 120% of the Committed Renewable Energy.
Cedar Creek II	PSCo has the right to either accept or decline any Excess Renewable Energy (120% of Committed Renewable Energy) produced during any commercial operation year.
Cedar Point	PSCo has the right to either accept or decline any Excess Renewable Energy (120% of Committed Renewable Energy) produced during any commercial operation year.
Comanche	PSCo has the right to accept or decline any energy produced in excess of 115% of the Committed Solar Energy
Fountain Valley 1-6	Seller shall offer any Excess Energy and/or Excess Capacity providing Company a Commercially Reasonable period of time of not less than 10 Business Days to respond to the offer.
Hooper	PSCo has the right to accept or decline any energy produced in excess of 115% of the Committed Solar Energy.
Limon I	PSCo has the right to either accept or decline any Excess Renewable Energy (115% of Committed Renewable Energy) produced during any commercial operation year.
Limon II	PSCo has the right to either accept or decline any Excess Renewable Energy (115% of Committed Renewable Energy) produced during any commercial operation year.
Neptune	PSCo has the right to accept or decline any energy produced in excess of 115% of the Committed Solar Energy.
San Luis	PSCo has the right to accept or decline any energy produced in excess of 115% of the Committed Solar Energy.
Spindle Hill 1 + 2	Seller shall offer any Excess Energy and/or Excess Capacity providing Company a Commercially Reasonable period of time of not less than 10 Business Days to respond to the offer.
Sun Mountain	PSCo has the right to accept or decline any energy produced in excess of 115% of the Committed Solar Energy.
Thunder Wolf	PSCo has the right to accept or decline any energy produced in excess of 115% of the Committed Solar Energy.
Titan	Seller shall notify Company promptly upon Seller's delivery of Renewable Energy hereunder that exceeds 110% of the Committed Energy for a Commercial Operation Year. Within 10 Business Days of any such notice, Company shall elect by notice to Seller either to accept or to decline any Excess Energy generated by the Facility through the balance of such Commercial Operation Year.

Table 2.4-7 and Highly Confidential Appendix B provide the performance characteristics of Public Service-owned energy storage systems including but not limited to discharge rates and durations, charging rates, response time, and cycling losses and limitations as required by Rule 3607(a)(VIII).

Table 2.4-7 Performance Characteristics of Public Service-Owned Energy Storage Systems

Energy Storage System / Technology	Discharge Rate	Duration (1)	Charging Rate (2)	Response Time	Cycling Losses / Limitations (3)
Cabin Creek A / 170 MW Pumped Hydro	170 MW Maximum	8 Hours	18.5 Hours	10 minutes Maximum	Requires 1.5 MW to pump same amount of water required to generate 1 MW. Cabin Creek is allowed to maintain a maximum of 2,020 acre feet of water in inventory. This allows for 1407 MW-hrs of generation with a full upper reservoir. This will decrease if water inventory is less due to losses.
Cabin Creek B / 170 MW Pumped Hydro	170 MW Maximum	8 Hours	18.5 Hours	10 minutes Maximum	
Cabin Creek A+B / 340 MW Pumped Hydro	340 MW Maximum	4 Hours	9.5 Hours	20 minutes Maximum	
Form Energy / 10 MW Iron-Air	X	X	X	X	X
2021 ERP & CEP Phase II Approved Resources					
Rocky Mountain / XXX XX XXXXXXXX XXXXXXXXXX	X	X	X	X	X
Bid 1085 / XXX XX XXXXXXXX XXXXXXXXXX	X	X	X	X	X

(1) Duration for maximum discharge rate.
(2) For Cabin Creek A and B, the charging rate indicates the time to fill the storage reservoir. For Form Energy, Rocky Mountain, and Bid 1085, the charging rate indicates the maximum power at which the battery can charge.
(3) Round trip efficiency values reported for 2028 (or next closest COD) to align with accredited capacity values reported for 2028 in the Company-Owned and Purchased Power resources tables.
Note: Highly Confidential data is indicated by blue highlight.

Table 2.4-8 and Highly Confidential Appendix B provide the performance characteristics of energy storage systems purchased from utilities and non-utilities, including but not limited to discharge rates and durations, charging rates, response time; and cycling losses and limitations as required by Rule 3607(a)(IX).

Table 2.4-8 Performance Characteristics of Energy Storage Systems Contracted Through PPA (Highly Confidential)

Energy Storage System / Technology	Discharge Rate	Duration (1)	Charging Rate (2)	Response Time	Cycling Losses / Limitations (3)
Neptune / 125 MW Lithium Ion Batteries	X	X	X	X	X
Thunder Wolf / 100 MW Lithium Ion Batteries	X	X	X	X	X
Bid 0589 / 200 MW Lithium Iron Phosphate (LFP)	X	X	X	X	X
Bid 0149 / 72 MW Lithium Ion	X	X	X	X	X
Bid 0282 / 250 MW Lithium Ion or similar	X	X	X	X	X
Bid 0303 / 100 MW Lithium Ion or similar	X	X	X	X	X
Bid 0467 / 250 MW Lithium Ion or similar	X	X	X	X	X
Bid 0249 / 199 MW Lithium Ion	X	X	X	X	X
Bid 0251 / 199 MW Lithium Ion	X	X	X	X	X

(1) Duration for maximum discharge rate.
(2) Maximum power at which the battery can charge.
(3) Round trip efficiency values reported for 2028 (or next closest COD) to align with accredited capacity values reported for 2028 in the Company-Owned and Purchased Power resources tables.
Note: Highly Confidential PPA data is indicated by blue highlight.

Projected Emissions of Existing Resources

Tables 2.4-9 through 2.4-18 provide the projected emissions, in terms of pounds per MWH and short-tons per year, of sulfur dioxide (SO_2), nitrogen oxides (NO_x), particulate matter (PM_10), mercury (HG) and carbon dioxide (CO_2) for: (1) generation facilities and energy storage systems owned by Public Service, and generation facilities from which Public Service has PPAs in effect at the time of this plan filing as required by Rule 3607(a)(X); and (2) generic resources included in the Company's modeling as required by Rule 3604(g). Additional projected emissions information from other scenarios modeled in Phase I is provided in Appendix C.

Table 2.4-9 Projected CO_2 Emissions (Tons) From Existing Resources

Projected CO2 Emissions (Tons) From Existing Resources - Base Load SCC								
	Base Plan Annual PRM (SCC)	Base Plan (SCC)	ADER Plan Annual PRM (SCC)	ADER Plan (SCC)	No New Gas Plan Annual PRM (SCC)	No New Gas Plan (SCC)	Nuclear Plan (SCC)	Comp Advanced Tech (SCC)
2025	15,956,378	15,951,096	15,956,378	15,951,091	15,956,372	15,951,090	15,951,090	15,951,094
2026	8,623,389	8,623,271	8,623,390	8,623,269	8,623,390	8,623,271	8,623,274	8,623,272
2027	8,426,234	8,420,546	8,426,234	8,420,546	8,423,403	8,421,361	8,420,563	8,420,545
2028	4,998,035	5,035,978	4,991,411	4,988,962	5,269,862	4,971,203	5,070,347	5,036,003
2029	3,998,234	3,942,158	3,879,829	3,859,016	3,788,977	3,531,955	3,959,280	3,942,157
2030	3,918,007	3,959,379	3,722,111	3,864,099	3,403,524	3,323,410	4,100,383	3,959,385
2031	1,977,101	1,923,939	1,952,865	2,022,411	1,637,245	1,323,098	1,849,943	1,938,207
2032	2,855,578	2,855,202	2,830,274	2,932,338	2,698,735	2,325,675	2,757,262	2,752,037
2033	1,853,972	1,918,208	1,853,079	1,922,104	2,017,115	1,464,659	1,900,673	1,798,500
2034	2,138,541	2,270,565	2,142,243	2,243,331	2,512,324	1,883,651	2,257,640	2,052,288
2035	1,484,277	1,402,245	1,518,935	1,499,047	1,421,100	576,467	1,519,748	1,775,571
2036	1,708,898	1,645,143	1,766,318	1,772,742	1,731,328	809,346	1,818,752	2,129,029
2037	1,658,936	1,685,649	1,728,608	1,710,235	1,749,289	1,084,960	1,798,062	1,242,861
2038	2,125,178	2,130,972	2,181,334	2,189,989	2,369,466	1,661,737	2,317,043	1,638,278
2039	1,469,380	1,483,414	1,538,398	1,517,726	1,634,057	1,304,640	1,369,984	995,290
2040	1,547,763	1,519,540	1,624,609	1,666,905	1,835,449	1,553,866	1,401,953	975,300
2041	2,053,199	2,003,141	2,093,006	2,059,990	2,190,141	2,124,211	1,882,809	1,294,915
2042	990,497	995,534	996,525	999,568	963,274	900,601	1,020,581	1,011,880
2043	1,040,813	1,058,612	1,059,827	1,074,013	1,156,502	1,097,013	1,147,376	1,150,513
2044	952,074	889,015	904,423	904,131	1,456,718	1,453,711	773,320	812,075
2045	61,225	65,299	72,864	78,981	120,487	123,810	104,390	127,509
2046	233,032	216,687	227,305	213,764	615,436	519,119	299,814	416,926
2047	498,472	470,697	490,878	469,266	747,994	719,630	519,270	584,770
2048	62,673	59,162	62,688	56,833	12,120	526	59,404	63,598
2049	99,812	81,805	100,220	84,695	75,431	11,335	86,068	82,460
2050	17,046	14,208	16,541	14,079	11,939	230	13,704	14,305

Table 2.4-10 Projected CO_2 Emissions (Tons) From Generic Resources

Projected CO2 Emissions (Tons) From Generic Resources - Base Load SCC								
	Base Plan Annual PRM (SCC)	Base Plan (SCC)	ADER Plan Annual PRM (SCC)	ADER Plan (SCC)	No New Gas Plan Annual PRM (SCC)	No New Gas Plan (SCC)	Nuclear Plan (SCC)	Comp Advanced Tech (SCC)
2025	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-
2028	58,740	80,609	-	30,089	-	-	83,733	80,609
2029	161,363	157,208	116,248	104,461	-	-	159,053	157,208
2030	282,977	295,271	217,868	196,225	-	-	304,174	295,271
2031	127,281	183,067	120,555	191,464	-	-	174,850	238,753
2032	315,691	338,163	277,315	367,475	-	-	319,112	413,423
2033	111,243	94,255	106,599	93,877	-	-	101,496	172,702
2034	212,627	182,346	210,053	179,447	-	-	191,425	280,479
2035	120,143	98,746	112,403	110,801	-	-	92,275	131,875
2036	197,596	148,978	181,519	162,736	-	-	149,490	208,226
2037	126,233	116,155	104,287	95,625	-	-	81,514	79,569
2038	128,990	169,945	117,095	152,974	-	-	154,983	136,196
2039	64,899	87,806	71,605	68,332	-	-	59,912	60,180
2040	104,255	142,341	115,488	118,985	-	-	102,721	83,267
2041	148,674	194,160	150,985	169,705	-	-	155,443	73,782
2042	304,605	329,766	322,458	324,691	-	-	425,618	377,613
2043	430,393	452,118	445,041	433,768	-	-	499,235	483,444
2044	509,733	569,380	557,439	555,629	-	-	659,165	633,646
2045	26,224	34,688	31,851	45,861	-	-	32,530	32,820
2046	78,706	87,849	81,741	86,051	-	-	98,255	98,000
2047	112,113	130,080	116,177	121,468	-	-	152,322	167,443
2048	54,250	60,387	54,277	52,795	-	-	59,957	59,576
2049	95,296	113,948	95,007	107,330	-	-	113,968	110,686
2050	33,965	35,150	34,070	37,811	-	-	33,396	30,888

Table 2.4-11 Projected SO_2 Emissions (Tons) From Existing Resources

Projected SOX Emissions (Tons) From Existing Resources - Base Load SCC								
	Base Plan Annual PRM (SCC)	Base Plan (SCC)	ADER Plan Annual PRM (SCC)	ADER Plan (SCC)	No New Gas Plan Annual PRM (SCC)	No New Gas Plan (SCC)	Nuclear Plan (SCC)	Comp Advanced Tech (SCC)
2025	5,135	5,131	5,135	5,131	5,135	5,131	5,131	5,131
2026	2,153	2,146	2,153	2,146	2,153	2,146	2,146	2,146
2027	2,541	2,541	2,541	2,541	2,660	2,632	2,541	2,541
2028	1,489	1,480	1,546	1,585	1,886	1,629	1,477	1,480
2029	705	733	704	732	753	742	733	733
2030	761	805	806	881	946	932	831	805
2031	14	142	26	172	207	236	111	94
2032	182	178	188	174	646	462	185	114
2033	27	12	39	18	209	10	15	12
2034	114	35	223	28	586	23	35	35
2035	51	14	34	20	103	12	15	11
2036	118	36	134	43	409	45	30	40
2037	41	10	63	10	256	28	20	9
2038	129	25	132	31	432	28	28	28
2039	19	10	26	10	169	10	11	10
2040	92	30	119	55	542	156	25	16
2041	85	8	92	21	657	481	7	4
2042	10	3	9	3	579	575	4	5
2043	13	4	7	4	580	543	4	5
2044	106	3	97	3	996	903	3	3
2045	12	12	4	10	28	48	2	4
2046	3	1	1	1	454	422	6	7
2047	8	2	3	2	503	519	10	19
2048	95	124	85	83	4	1	97	118
2049	146	134	144	117	161	26	100	102
2050	28	9	30	9	35	0	6	8

Table 2.4-12 Projected SO_2 Emissions (Tons) From Generic Resources

Projected SOX Emissions (Tons) From Generic Resources - Base Load SCC								
	Base Plan Annual PRM (SCC)	Base Plan (SCC)	ADER Plan Annual PRM (SCC)	ADER Plan (SCC)	No New Gas Plan Annual PRM (SCC)	No New Gas Plan (SCC)	Nuclear Plan (SCC)	Comp Advanced Tech (SCC)
2025	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-
2028	0	0	-	0	-	-	0	0
2029	1	1	1	1	-	-	1	1
2030	2	2	1	1	-	-	2	2
2031	1	1	1	1	-	-	1	1
2032	2	2	2	2	-	-	2	2
2033	1	1	1	1	-	-	1	1
2034	1	1	1	1	-	-	1	2
2035	1	1	1	1	-	-	1	1
2036	1	1	1	1	-	-	1	1
2037	1	1	1	1	-	-	0	0
2038	1	1	1	1	-	-	1	1
2039	0	0	0	0	-	-	0	0
2040	1	1	1	1	-	-	1	0
2041	1	1	1	1	-	-	1	0
2042	2	2	2	2	-	-	2	2
2043	2	2	2	2	-	-	3	3
2044	3	3	3	3	-	-	4	3
2045	0	0	0	0	-	-	0	0
2046	0	0	0	0	-	-	0	0
2047	1	1	1	1	-	-	1	1
2048	0	0	0	0	-	-	0	0
2049	1	1	1	1	-	-	1	1
2050	0	0	0	0	-	-	0	0

Table 2.4-13 Projected NO_x Emissions (Tons) From Existing Resources

Projected NOX Emissions (Tons) From Existing Resources - Base Load SCC								
	Base Plan Annual PRM (SCC)	Base Plan (SCC)	ADER Plan Annual PRM (SCC)	ADER Plan (SCC)	No New Gas Plan Annual PRM (SCC)	No New Gas Plan (SCC)	Nuclear Plan (SCC)	Comp Advanced Tech (SCC)
2025	6,005	6,012	6,005	6,012	6,005	6,012	6,012	6,012
2026	2,493	2,500	2,493	2,500	2,493	2,500	2,500	2,500
2027	8,749	8,722	8,570	8,740	11,683	11,233	8,700	8,547
2028	2,973	2,869	4,067	4,800	10,415	6,013	2,595	2,847
2029	862	1,353	846	1,342	1,890	1,631	1,330	1,292
2030	2,305	2,873	3,617	4,170	6,912	6,896	3,023	2,935
2031	301	2,491	577	2,860	3,936	4,364	1,977	1,724
2032	3,208	2,926	3,336	3,068	12,801	8,916	3,355	2,117
2033	559	249	686	311	3,901	211	275	241
2034	2,120	530	3,684	435	11,427	539	521	503
2035	879	242	537	376	2,169	233	309	231
2036	2,122	639	2,448	757	8,044	853	553	707
2037	780	219	1,129	220	4,939	569	343	177
2038	2,341	478	2,505	580	8,739	513	528	500
2039	344	204	496	207	3,446	187	209	181
2040	1,593	555	2,059	906	10,512	2,942	507	385
2041	1,514	203	1,671	418	12,600	9,280	179	123
2042	176	69	175	70	11,151	11,117	71	114
2043	243	77	109	80	11,203	10,489	95	99
2044	1,757	59	1,435	60	19,867	17,633	52	54
2045	234	153	69	178	564	1,008	43	63
2046	45	16	16	15	8,734	8,059	103	137
2047	99	30	61	30	9,623	9,996	162	301
2048	1,666	2,085	1,460	1,499	96	19	1,677	2,104
2049	2,434	2,308	2,398	2,026	3,077	555	1,776	1,764
2050	470	140	500	143	692	2	79	121

Table 2.4-14 Projected NO_x Emissions (Tons) From Generic Resources

Projected NOX Emissions (Tons) From Generic Resources - Base Load SCC								
	Base Plan Annual PRM (SCC)	Base Plan (SCC)	ADER Plan Annual PRM (SCC)	ADER Plan (SCC)	No New Gas Plan Annual PRM (SCC)	No New Gas Plan (SCC)	Nuclear Plan (SCC)	Comp Advanced Tech (SCC)
2025	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-
2028	22	30	-	11	-	-	31	30
2029	59	58	43	39	-	-	58	58
2030	103	108	80	72	-	-	111	108
2031	47	67	44	71	-	-	64	88
2032	117	125	103	136	-	-	118	152
2033	41	35	39	35	-	-	37	63
2034	78	67	77	66	-	-	70	103
2035	44	36	41	41	-	-	33	48
2036	72	54	67	60	-	-	55	76
2037	46	42	38	35	-	-	30	29
2038	47	62	43	56	-	-	57	49
2039	24	32	26	25	-	-	22	22
2040	38	52	43	44	-	-	38	30
2041	55	71	56	63	-	-	57	27
2042	72	75	74	78	-	-	92	88
2043	101	102	103	103	-	-	108	117
2044	124	133	132	135	-	-	138	146
2045	7	9	8	12	-	-	8	8
2046	19	23	19	23	-	-	22	25
2047	26	31	26	29	-	-	33	39
2048	18	19	18	17	-	-	19	18
2049	31	36	30	34	-	-	35	35
2050	14	14	14	15	-	-	13	13

Table 2.4-15 Projected HG Emissions (Tons) From Existing Resources

Projected HG Emissions (Tons) From Existing Resources - Base Load SCC								
	Base Plan Annual PRM (SCC)	Base Plan (SCC)	ADER Plan Annual PRM (SCC)	ADER Plan (SCC)	No New Gas Plan Annual PRM (SCC)	No New Gas Plan (SCC)	Nuclear Plan (SCC)	Comp Advanced Tech (SCC)
2025	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0	0
2031	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-

Table 2.4-16 Projected HG Emissions (Tons) From Generic Resources

Projected HG Emissions (Tons) From Generic Resources - Base Load SCC								
	Base Plan Annual PRM (SCC)	Base Plan (SCC)	ADER Plan Annual PRM (SCC)	ADER Plan (SCC)	No New Gas Plan Annual PRM (SCC)	No New Gas Plan (SCC)	Nuclear Plan (SCC)	Comp Advanced Tech (SCC)
2025	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-

Table 2.4-17 Projected PM_10 Emissions (Tons) From Existing Resources

Projected PM_10 Emissions (Tons) From Existing Resources - Base Load SCC								
	Base Plan Annual PRM (SCC)	Base Plan (SCC)	ADER Plan Annual PRM (SCC)	ADER Plan (SCC)	No New Gas Plan Annual PRM (SCC)	No New Gas Plan (SCC)	Nuclear Plan (SCC)	Comp Advanced Tech (SCC)
2025	202	202	202	202	202	202	202	202
2026	157	157	157	157	157	157	157	157
2027	1,521	1,513	1,558	1,509	1,785	1,657	1,517	1,549
2028	472	362	689	786	1,635	913	414	367
2029	83	187	81	178	223	194	193	200
2030	391	582	645	835	1,134	1,016	603	569
2031	40	520	68	666	694	815	401	332
2032	666	695	682	638	2,077	1,524	656	400
2033	83	36	140	65	727	28	49	34
2034	393	149	863	117	1,917	65	148	156
2035	182	47	130	60	303	21	39	33
2036	412	127	468	156	1,336	139	100	140
2037	139	33	227	34	855	83	73	24
2038	458	86	444	108	1,350	94	95	95
2039	59	28	83	29	527	25	28	20
2040	363	123	465	234	1,810	547	100	54
2041	334	43	350	95	2,230	1,619	37	27
2042	42	18	40	18	1,928	1,899	18	23
2043	49	19	34	20	1,926	1,797	22	25
2044	414	17	414	17	3,232	3,035	15	16
2045	37	54	13	36	92	144	10	19
2046	19	5	5	4	1,508	1,413	24	29
2047	40	9	14	9	1,681	1,720	41	81
2048	347	470	320	297	9	5	362	425
2049	562	496	550	435	554	77	362	379
2050	107	35	115	33	120	0	24	34

Table 2.4-18 Projected PM_10 Emissions (Tons) From Generic Resources

Projected PM_10 Emissions (Tons) From Generic Resources - Base Load SCC								
	Base Plan Annual PRM (SCC)	Base Plan (SCC)	ADER Plan Annual PRM (SCC)	ADER Plan (SCC)	No New Gas Plan Annual PRM (SCC)	No New Gas Plan (SCC)	Nuclear Plan (SCC)	Comp Advanced Tech (SCC)
2025	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-
2028	2	3	-	1	-	-	3	3
2029	6	5	4	4	-	-	5	5
2030	10	10	7	7	-	-	10	10
2031	4	6	4	7	-	-	6	8
2032	11	12	10	13	-	-	11	14
2033	4	3	4	3	-	-	3	6
2034	7	6	7	6	-	-	7	10
2035	4	3	4	4	-	-	3	4
2036	7	5	6	6	-	-	5	7
2037	4	4	4	3	-	-	3	3
2038	4	6	4	5	-	-	5	5
2039	2	3	2	2	-	-	2	2
2040	4	5	4	4	-	-	4	3
2041	5	7	5	6	-	-	5	2
2042	15	16	16	16	-	-	22	18
2043	21	23	22	22	-	-	26	23
2044	25	28	28	27	-	-	35	32
2045	1	1	1	2	-	-	1	1
2046	3	4	4	4	-	-	5	4
2047	5	6	5	5	-	-	7	8
2048	2	2	2	2	-	-	2	2
2049	4	4	4	4	-	-	4	4
2050	2	2	2	2	-	-	2	2

Demand-Side Management

Rule 3607(a)(XI) requires the Company to describe the expected demand-side resources during the resource planning period from existing measures installed through Company-administered programs; and, from measures expected to be installed in the future through Company-administered programs in accordance with a Commission-approved plan.

For purposes of determining resource need the Company has used the approved demand response and electric energy savings goals from the Commission's decision (Decision No. C23-0413) in the 2022 Strategic Issues proceeding (Proceeding No. 22A-0309EG). Table 2.4-19 reflects the approved demand response goals.

Table 2.4-19 Demand Response Goals (MW)

Demand Response (DR)	2024	2025	2026
Summer DR Goal	630	651	675
Winter DR Goal	290	301	322

To incorporate the impacts of future energy efficiency savings, the Company has reduced its sales forecast energy efficiency programs through 2026 consistent with the Commission's order in Proceeding No. 22A-0309EG. Table 2.4-20 reflects the energy efficiency targets through 2026.

Table 2.4-20 Energy Efficiency Goals (GWh)

Energy Efficiency	2024	2025	2026
Energy Efficiency Target	450	450	450

2.5 TRANSMISSION RESOURCES

In this Section, the Company provides Transmission Resources information required by Rule 3608 as described below. This Section begins with an overview of the electric transmission system and existing transmission capabilities, and a discussion of transfer capability limitations on the transmission network. Next, this Section discusses transmission projects implemented since the 2021 ERP & CEP and other transmission facilities and upgrades planned through 2031. This section also provides an update on the status of Colorado's Power Pathway 345 kV Transmission Project and the associated May Valley-Longhorn Extension. Last, this Section discusses transmission service and coordination agreements.

Electric Transmission System Overview

As of 2024, Public Service owns and maintains approximately 5,000 circuit-miles of transmission lines, all of which are located inside Colorado. The transmission lines are rated 44 kV, 69 kV, 115 kV, 138 kV, 230 kV, and 345 kV. The Company also uses approximately 235 transmission and distribution substations to transform and deliver electric energy.

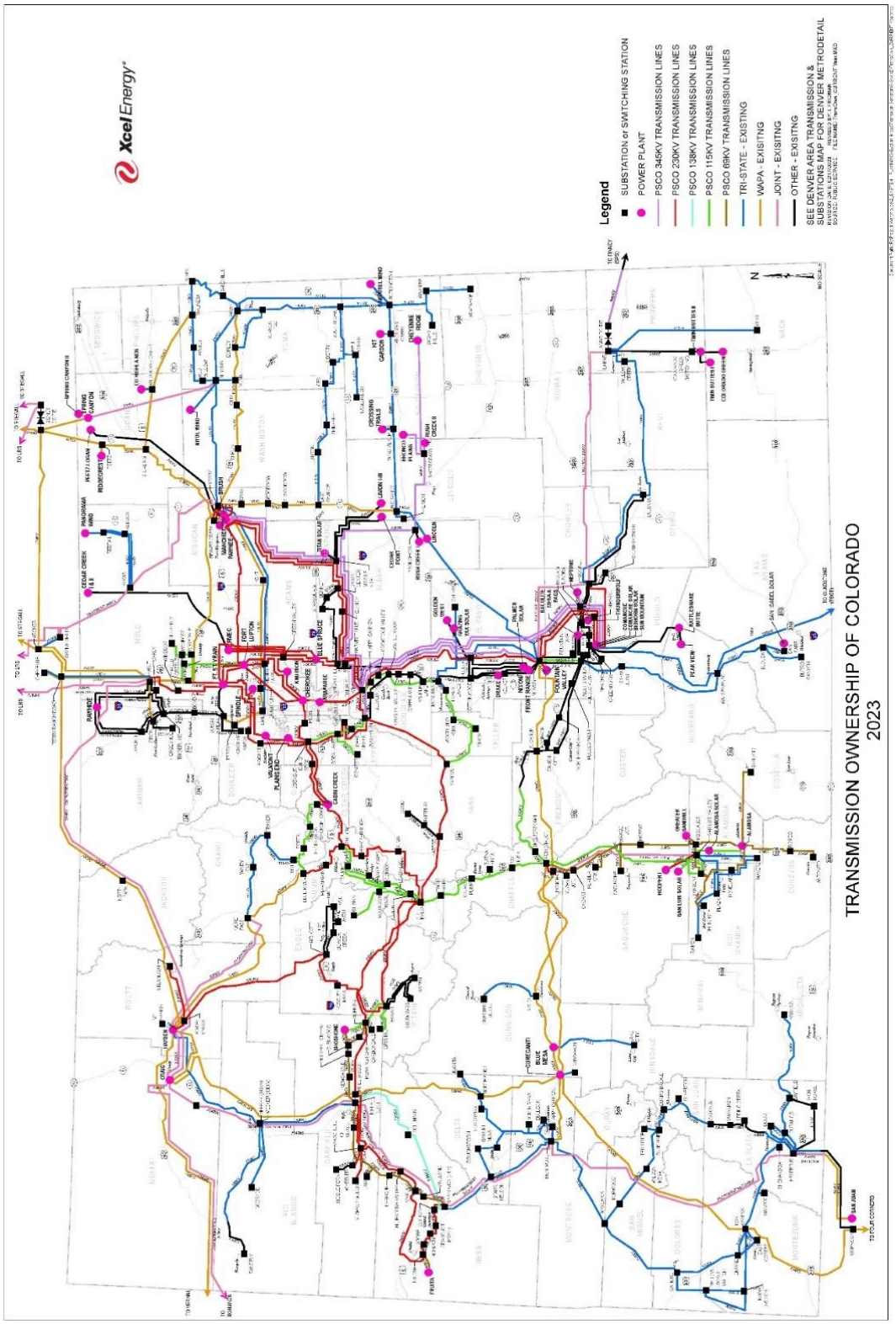
Colorado is on the eastern edge of the Western Electric Interconnection, which operates asynchronously from the Eastern Electric Interconnection. The Public Service–Southwestern Public Service Company Tie-line and 210 MW High Voltage Direct Current ("HVDC") back-to-back converter station, in-service since December 31, 2004, provides the first link in Colorado between the two interconnections.

Public Service has ownership in the jointly owned western slope transmission facilities extending from the Craig/Hayden area in Northwestern Colorado south to the Four Corners area.

The bulk power transmission system within the Denver/Boulder metro area consists primarily of a double-circuit 230 kV loop around the Denver metro region. This outer belt loop feeds into the 230 kV and 115 kV load-serving networks at various points on the system. 345 kV transmission helps serve the Denver metro loads with wind and solar generation resources located in the Pawnee, Limon, and Pueblo areas.

Figure 2.5-1 shows a map of the 2023 Colorado Transmission System including Public Service's transmission facilities.

Figure 2.5-1 Colorado Transmission Map



TOT Transfer Capability Limitations

In this Section, the Company provides information regarding the location and extent of transfer capability limitations on its transmission network as required by Rule 3608(a).

Public Service shares ownership in four jointly owned transmission corridors within the Colorado/Wyoming/Utah/New Mexico area. These jointly owned transmission corridors are called "TOTs," which is an acronym for "total of transmission." These TOTs are numbered 2A, 3, 5, and 7. The Total Transfer Capability ("TTC") across these TOTs is developed regularly by coordination and agreement of the owners of the TOT facilities.

The North American Electric Reliability Corporation ("NERC") is a not-for-profit international regulatory authority whose mission is to assure the reliability of the bulk power system in North America. NERC develops and enforces Reliability Standards, annually assesses seasonal and long-term reliability, monitors the bulk power system through system awareness, and educates, trains, and certifies industry personnel. The Southwest Power Pool ("SPP") also provides situational awareness and real-time monitoring of the TOTs in its role as the Reliability Coordinator ("RC") for Public Service.

The Rocky Mountain Operating Study Group ("RMOSG"), of which Public Service is a participating member, reviews and approves the TTCs for each of the four TOTs (2A, 3, 5 and 7). The RMOSG is one of four Regional Study Groups in the Western Electricity Coordinating Council ("WECC") that annually performs studies to determine the seasonal TTCs. Each Regional Study Group is responsible for reviewing and approving the seasonal TTCs and submitting the results to SPP.

Presently, Public Service's TTC allocations on these TOTs are committed to serve Public Service native load. Public Service posts available transmission capability ("ATC") on the WestTrans OASIS node at http://www.oatioasis.com. Transmission tariffs, including transmission terms, conditions, and pricing, are posted on the WestTrans OASIS node.

Figure 2.5-2 illustrates the most current TOT locations. The power transferred across these TOT paths is continuously monitored by the designated operating agent for each TOT to ensure that the path limits (TTCs) are not exceeded. All TOTs have been rated by WECC and the Transmission Providers that jointly own the TOTs. Public Service shows TOT 1A in Figure 2.5-2 but does not further describe the TOT in this report as Public Service does not have any transmission rights on TOT 1A.

Figure 2.5-2 Colorado TOT Transmission Path Map

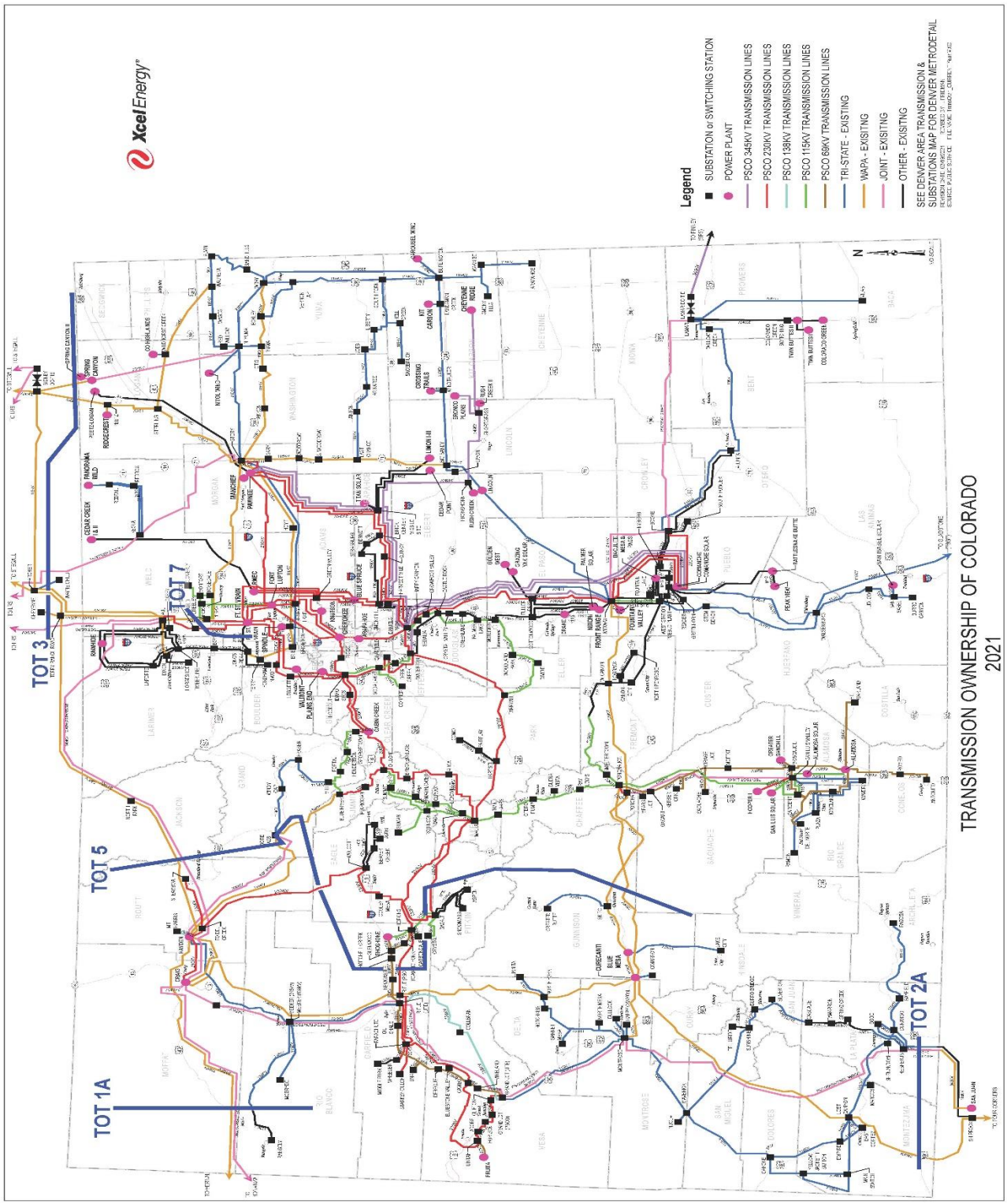


Table 2.5-1 shows Public Service's TOT capability on each path.

Table 2.5-1 TOT Transmission Transfer Capability Limitations (2024)

Path	Transmission Lines	Public Service Firm Path Transfer Capability (MW)		Public Service Capability Committed (MW)
TOT 2A	Waterflow-San Juan 345 kV Hesperus-Glade Tap 115 kV Lost Canyon-Shiprock 230 kV	135 north-south	200 south-north	135 north-south 200 south-north
TOT 3	Archer-Ault 230 kV LRS-Ault 345 kV Wayne Child-Keota 345 kV Cheyenne-Owl Creek 115 kV Sidney-Sterling 115 kV Sidney-Spring Canyon 230 kV Cheyenne-Ault 230 kV	56 north-south	56 south-north	56 north-south 0 south-north
TOT 5	North Park-Archer 230 kV Craig-Ault 345 kV Hayden-Gore Pass 230 kV Hayden-Gore Pass 138 kV Gunnison – Poncha 115 kV Curecanti-Poncha 230 kV Hopkins-Malta 230 kV Basalt-Malta 230 kV	480 west-east	480 east-west	480 west-east 480 east-west
TOT 7	Weld-Fort St. Vrain 230 kV Longs Peak -FSV 230 kV Ault-Fort St. Vrain 230 kV	516 north-south	516 south-north	516 north-south 2 south-north

TOT 2A

TOT 2A represents the transmission path that connects southwestern Colorado with New Mexico and Arizona. This path is comprised of three transmission lines and has a north to south limit of 690 MW minus net load in the Montrose-Curecanti-San Juan-Shiprock area of southwest Colorado. The limit is based on a single contingency of the Hesperus-San Juan 345 kV line. The path is jointly owned by WAPA, Tri-State, and Public Service. The south to north limit is not defined, but Public Service has ownership rights to 200 MW of transfer capability in the south to north direction on this path and a 135 MW share of the maximum north to south transfer capability of 690 MW. However, the limit is dynamic and monitored continuously. The limit is also highly dependent on local southwest Colorado loads and drops significantly as the loads increase and when southwest Colorado generation is off-line.

TOT 3

TOT 3 is the transmission path that connects Wyoming and Nebraska with northeastern Colorado. This path is comprised of seven transmission lines and presently has a maximum north to south transfer limit of 1,843 MW that is adjusted seasonally to account for load and local generation variations.

WAPA, Tri-State, Basin Electric Power Cooperative, Wyoming Municipal Power Agency, Municipal Energy Agency of Nebraska, Los Alamos County and Public Service jointly own the TOT 3 transmission lines. Public Service owns 3.57% of the path which equites to 60 MW of firm transfer capability on TOT 3 in the north to south direction. Since the south to north limit is not defined at this time, Public Service-owned transfer capability is the same 60 MW south to north.

Operationally, TOT 3 is the most constraining transmission path used to import power into eastern Colorado. Once the TOT 3 capacity limit is reached, further schedules into eastern Colorado over TOT 5 result in the overloading of TOT 3. In this condition the overloading of TOT 3 is due to the increased (west to east) flow on TOT 5's North Park-Terry Ranch Road 230 kV line into Wyoming, resulting in an increased (north to south) flow on TOT 3's Terry Ranch Road-Ault 230 kV line into Colorado.

TOT 5

TOT 5 represents the transmission path that connects western Colorado to eastern Colorado. The TOT 5 path is comprised of eight transmission elements and presently has a west to east operating transfer limit of 1,680 MW. The west to east rating of the path is defined through established operating practices. WAPA, Tri-State, Platte River Power Authority ("PRPA"), and Public Service jointly own the TOT 5 transmission lines. Public Service owns 480 MW of firm transfer capability on TOT 5 in the west to east direction and, since the east to west limit is not defined through the WECC process, it is studied by WAPA and Public Service-owned transfer capability is 388 MW east to west.

Public Service's firm transfer capability in the west to east direction on TOT 5 is fully committed to transmitting capacity and associated energy from the Company's purchased power resources and from Company-owned resources located in western Colorado. Public Service has committed the east to west direction as backup for western Colorado loads and for counter-scheduling needs.

TOT 7

TOT 7 is south of the TOT 3 path and consists of three transmission lines that transfer power to the north Denver metro area. The TOT 7 path has a north to south transfer limit of 890 MW. The south to north transfer limit is not defined at this time.

Public Service and PRPA jointly own TOT 7. Public Service owns 516 MW of firm transfer capability on TOT 7. Since TOT 7 is located east of TOT 5 and south of TOT 3, TOT 7 use generally requires coordinated use of both the TOT 3 and TOT 5 paths.

Senate Bill 07-100 New Transmission Additions

Rule 3608(b) requires the Company to provide a description of all transmission lines and facilities appearing in its most recent report filed with the Commission pursuant to § 40-2-126, C.R.S. that, as identified in that report, could reasonably be placed into service during the RAP.

Senate Bill 07-100 ("SB 07-100"), which is codified at § 40-2-126, C.R.S., was signed into law in 2007 to expand Colorado's electric transmission system and promote the use of renewable resources. It established requirements for utilities to continually evaluate and, if necessary, improve electric transmission facilities to meet the state's existing and future energy needs. Five Energy Resource Zones ("ERZs") with significant renewable energy potential were also identified. Historically, Public Service filed SB 07-100 Reports by October 31 of each odd-numbered year. In 2017, Decision No. R17-0747 in Proceeding No. 17R-0489E subsequently modified the Commission's Rules implementing SB 07-100 to allow the Company to demonstrate compliance with the requirements of SB 07-100 as part of the biennial 10-Year Transmission Plan filed pursuant to Rule 3627 ("Rule 3627 Report"), combining the two filings into a single proceeding. The SB 07-100 Report is now located within the Rule 3627 Report. The Company filed its most recent 10-Year Transmission Plan and 20-Year Conceptual Scenario Report in compliance with Rule 3627 in February 2024 (Proceeding No. 24M-0050E. The 2024 Rule 3627 Report is available on Xcel Energy's Transmission website.[3]

Energy Resource Zones

Public Service first designated ERZs in its 2007 SB 07-100 Report, and through its subsequent 2008 Informational Report and 2009 SB 07-100 Report revised those designated ERZs to the number and status described below:

> ERZ 1: In Northeast Colorado, ERZ 1 includes all or parts of Sedgwick, Phillips, Yuma, Washington, Logan, Morgan, Weld, and Larimer Counties. The geography of this ERZ is similar to the way it was described in the 2007 SB 07-100 Report, but it has been redrawn to provide clarity so that major metropolitan areas (particularly the greater Denver metro area) are not included in any ERZ.
>
> ERZ 2: ERZ 2 is in East Central Colorado, and includes all or parts of Yuma, Washington, Adams, Arapahoe, Elbert, El Paso, Lincoln, Kit Carson, Kiowa, and Cheyenne Counties. The geography of this ERZ is also similar to that described in the 2007 SB 07-100 Report but has been

[3] http://www.transmission.xcelenergy.com/Planning/Planning-for-Public-Service-Company-of-Colorado.

redrawn to remove the greater Denver metro area as well as parts of Colorado Springs.

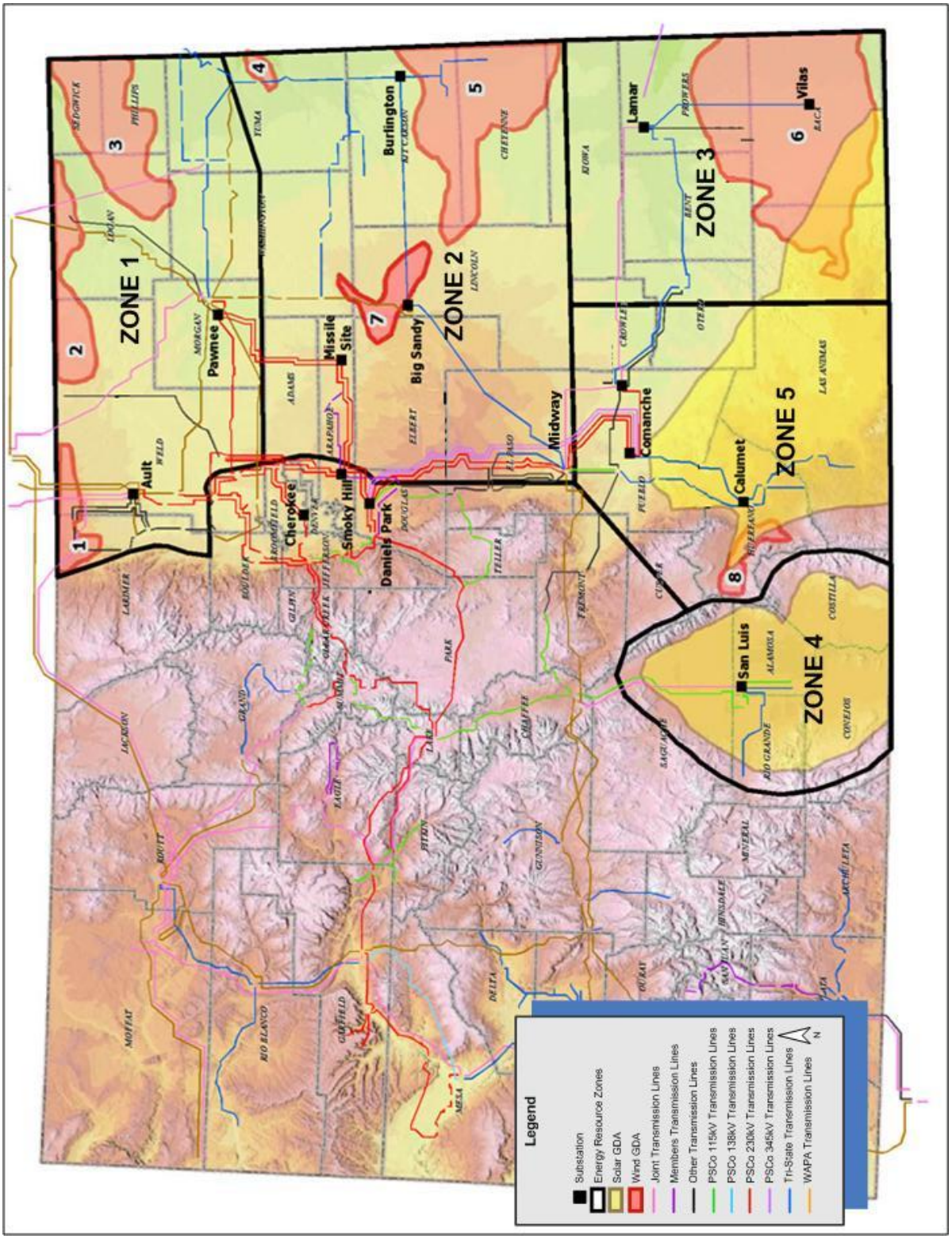
ERZ 3: ERZ 3 is in Southeast Colorado, and includes all or parts of Baca, Prowers, Kiowa, Crowley, Otero, Bent, and Las Animas Counties. This ERZ is somewhat smaller than the ERZ 3 that was described in the 2007 SB 07-100 Report; its western portion is now in ERZ 5.

ERZ 4: ERZ 4 is in the San Luis Valley, and includes all or parts of Costilla, Conejos, Rio Grande, Alamosa, and Saguache Counties. This ERZ is somewhat smaller than the ERZ 4 created for the 2007 SB 07-100 Report, as it now includes only the San Luis Valley region and does not include any of wind Generation Development Area ("GDA") 8 which is now located wholly within the new ERZ 5.

ERZ 5: ERZ 5 is in South-Central Colorado, and includes all or parts of Huerfano, Pueblo, Otero, Crowley, Custer, and Las Animas Counties.

Figure 2.5-3 illustrates the five ERZs overlaid upon the wind and solar GDAs that were identified in the 2007 Senate Bill 07-091 Task Force Report.

Figure 2.5-3 Energy Resource Zones with Generation Development Areas



Pursuant to Rule 3608(b) and 3608(c), Table 2.5-2 below provides a description of all transmission lines and facilities appearing in the Company's most recent report filed with the Commission pursuant to § 40-2-126, C.R.S. (i.e., the February 2024 Rule 3627 Report), that, as identified in that report, could reasonably be placed into service during the RAP.

The SB 07-100 project that is likely to be placed in service during the RAP is Colorado's Power Pathway 345 kV Transmission Project, which is described in detail below.

Table 2.5-2 SB 07-100 Projects Likely to be In-Service During the RAP

Project	ERZs	CPCN Status	Currently Scheduled In-Service Date	Estimated Cost ($ millions)	Injection Capability	Approximate Length (Miles)
Colorado's Power Pathway Transmission Project	1, 2, 3, 5	Filed on March 2, 2021	2025 – 2027	1,750	3000 – 3500	560

Implemented SB 07-100 Transmission Projects Since the 2021 ERP & CEP

No SB 07-100 Transmission Projects have been placed in service since the 2021 ERP; however, the Colorado's Power Pathway 345 kV Transmission Project is currently under construction and segments will be placed in service between 2025 and 2027 as described below.

Colorado's Power Pathway 345 kV Transmission Project

The Commission approved a CPCN for the Colorado's Power Pathway 345 kV Transmission Project (the "Pathway Project") in Proceeding No. 21A-0096E. The Pathway Project is a 550-mile, 345 kilovolt ("kV") double circuit transmission facility that will provide a high voltage networked transmission facility that interconnects the Eastern Plains and Southern Colorado to Public Service's load centers, providing developers the ability to develop and bid cost-effective projects into renewable-rich ERZs 1, 2, 3, and 5.

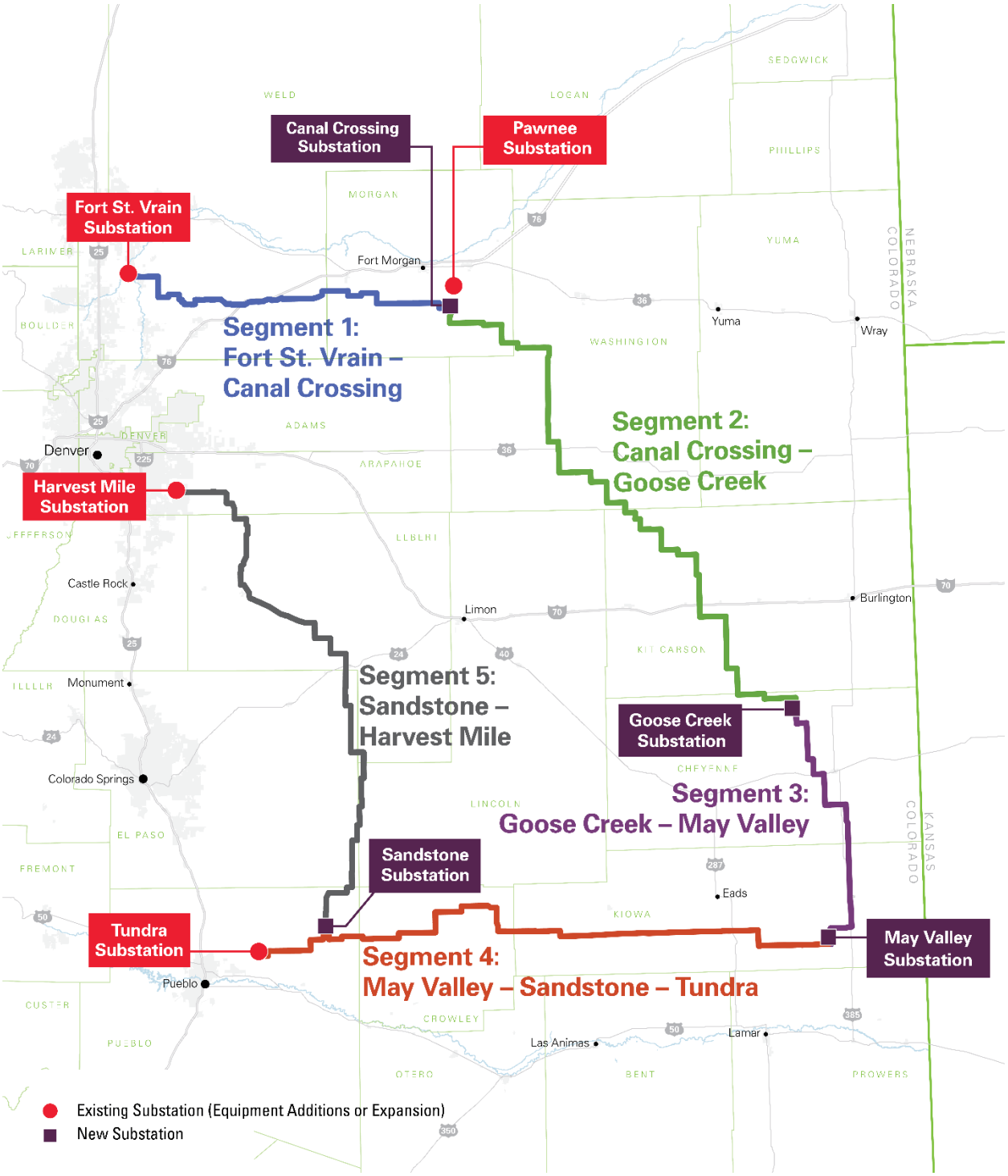
The northern terminus of the Pathway Project is at the Company's existing Fort St. Vrain Substation, located in Platteville, Colorado, in western Weld County. Segment 1 of the Pathway Project spans approximately 75 miles east to a new switching station, Canal Crossing, located near the existing Pawnee Substation. Segment 2 will proceed approximately 145 miles east/southeast to the new Goose Creek Switching Station in Cheyenne County, near the Cheyenne Ridge Wind Project. Segment 3 will proceed approximately 60 miles south to the new May Valley Switching Station near Lamar in Kiowa County, and then turn back west. Segment 4 of the Pathway Project was planned to run west from the May Valley Switching Station approximately 140 miles, terminating at the now existing Tundra Switching Station in Pueblo County. Segment 5 was to

proceed north from the Tundra Switching Station 120 miles and terminate at the existing Harvest Mile substation in Arapahoe County. The Company filed an application for a CPCN (filed on March 19, 2024 in Proceeding No. 24A-0131E) to slightly modify the scope of the Pathway Project by adding the new Sandstone Switching Station along Segment 4 approximately 15 miles east of the Tundra Switching Station and relocating the southern terminus of Segment 5 from the Tundra Switching Station to the Sandstone Switching Station. If approved, the addition of the Sandstone Switching Station to the Pathway Project will reduce the currently estimated cost of the Pathway Project and enable a greater number of future resource interconnections.

The Pathway Project is currently under construction, with Segments 2 and 3 and the Canal Crossing, Goose Creek, and May Valley Switching Stations planned to be placed in-service in 2025. Segment 1 is planned to be placed in service in 2026 and Segments 4 and 5 and the Sandstone Switching Station, if approved, are planned to be placed in service in 2027.

A map Pathway Project is shown in Figure 2.5-4 below.

Figure 2.5-4 Pathway Project Map



The Pathway Project will effectuate an interconnected transmission system that: (1) achieves improved reliability and operational flexibility while interconnecting needed clean generation resources; and (2) enables the delivery of electric energy from these generation resources to the Company's load centers. An additional benefit of the Pathway Project is that it will network a large portion of the existing, Rush Creek and Cheyenne Ridge 345 kV transmission line(s) that together effectively comprise a 153-mile radial generator tie-line currently connected to Public Service's networked transmission system only at Missile Site Substation.

May Valley-Longhorn Extension

In Proceeding No. 21A-0096E, the Company also put forth an optional portion of the Pathway Project known as the May Valley – Longhorn Extension ("MVLE"), or Segment 6. The MVLE would involve constructing approximately 60 miles of new 345 kV double circuit transmission line from the new May Valley Substation south to a new Longhorn Substation located near Vilas, Colorado. This extension to the Pathway Project would establish additional transmission interconnection opportunities for potential clean energy resource developers in the wind-rich southeastern area of the state. The Company anticipates that having a well-planned transmission line to this area will not only facilitate clean energy resource development, but also minimize the potential likelihood of clean energy project developers needing to construct multiple generation tie lines in this region to interconnect to the Pathway Project, at potentially high costs to individual generation projects bid into this and future ERPs.

The Commission conditionally approved a CPCN for the MVLE in Proceeding No. 21A-0096E. The unconditional granting of the CPCN was dependent on the inclusion of the MVLE in the resource portfolio approved by the Commission in Proceeding No. 21A-0141E. While the MVLE was not included in the approved resource portfolio, by Decision No. C24-0161 in Proceeding No. 21A-0141E (Phase II ARRR Decision), the Commission stated that it will maintain the conditional CPCN for the MVLE through the 2024 JTS. The Commission found that, consistent with what it contemplated in Proceeding No. 21A-0096E for the 2021 ERP & CEP, if the approved portfolio in the 2024 JTS includes the MVLE, the Company will receive a full CPCN for the MVLE. The Commission further found that given that the finding of need for the MVLE is inextricably linked to its cost, the Commission directed the Company to present updated cost estimates for the MVLE in Phase I of the 2024 JTS.

MVLE Updated Cost Estimate

The updated MVLE cost estimate uses the same major cost categories as those set forth in the Power Pathway CPCN Proceeding (21A-0096E), including: (1) Engineering, Permitting, and Project Management, (2) Land/Easements, (3) Materials, and (4)

Construction. The total project cost estimate also includes a Risk Reserve allocated across the four main cost categories plus overhead and escalation. Pursuant to the Commission's directive in its Phase II ARRR Decision, the Company prepared an updated cost estimate for the MVLE in July 2024. The updated total project cost estimate is approximately $271.6 million. Appendix D provides the MVLE updated cost estimate allocated across the cost categories described above.

Other Transmission Facility Additions Pursuant to § 40-2-126, C.R.S. (2024 Rule 3627 Report)

The Company has plans for new transmission facilities and system upgrades as outlined below.

Transmission Facilities/Upgrades completed since 2022 and/or scheduled for completion in 2024:

- Greenwood – Denver Terminal 230 kV Line
- Ault-Cloverly 230/115 kV Transmission Project
  - Ault – Husky 230 kV line
  - Husky – Collins Street – Cloverly 115 kV line
  - Husky 230/115 kV Substation
  - Collins Street 115 kV Station
- Generator Interconnection Facilities
  - Mirasol 230 kV Switching Station
  - Tundra 345 kV Switching Station
  - Generator Interconnection at Comanche Substation (CEPP Bid 077)
- Distribution Substations
  - Avery Distribution Substation
  - High Point Distribution Substation
- Bluestone Valley Substation Phase 2
- CEPP Voltage/Reactive Support Facilities
- Flying Horse Flow Mitigation

Transmission Facilities/Upgrades Planned through 2030:[4]

- Colorado's Power Pathway Project
  - Fort Saint Vrain 345 kV Switching Station Expansion
  - Segment 1 Fort Saint Vrain to Canal Crossing
  - Canal Crossing 345 kV Switching Station
  - Pawnee 345 kV Switching Station Expansion
  - Segment 2 Canal Crossing to Goose Creek
  - Goose Creek 345 kV Switching Station
  - Segment 3 Goose Creek to May Valley
  - May Valley 345 kV Switching Station

[4] Excluding the Pathway Project.

Segment 4 May Valley to Sandstone to Tundra
Sandstone 345 kV Switching Station
Tundra 345 kV Switching Station Expansion
Segment 5 Sandstone to Harvest Mile
Harvest Mile 345 kV Switching Station Expansion
Pathway Project Reactive/Voltage Support Facilities

- Avon – Gilman 115 kV Transmission Line
- Climax – Robinson Rack – Gilman 115 kV Line
- Leetsdale – Elati 230 kV Line Upgrade
- Denver Metro Area Network Upgrades
  - Note: scope has changed from descriptions in 2024 Rule 3627 Report. See https://www.rmao.com/public/wtpp/Operating_Studies/ERP%20Phase%20II_Transmission%20Planning%20Study_10.11.24.pdf
- San Luis Valley Network Upgrades
  - [Note: scope is under further evaluation and may change from descriptions in 2024 Rule 3627 Report]
- Distribution Substations
  Barker Distribution Substation
  Kestrel Distribution Substation
  Poder Distribution Substation
  Metro Water Recovery Substation
- Generator Interconnection Facilities
  Generation Interconnection at Midway Substation (GI-2024-6)
  Stagecoach Switching Station

For additional information required by Rule 3608(c), please see Proceeding No. 24M-0005E (2024 Rule 3206 Report) and Proceeding No. 24M-0050E (2024 Rule 3627 10-Year Transmission Plan, Appendix F) for additional details.

Transmission Injection Capability

Injection[5] capability at any system location is inherently a moving target that varies with the prevailing system conditions characterized by system load level and economic generation dispatch. This is primarily driven by: (1) the coincident[6] production of wind and solar at system peak times, and (2) the hourly output capacity and interconnection locations of each interconnected generation resource.

The injection capability determined for a given location in the transmission system is highly dependent on the assumed generation and storage dispatch pattern. Therefore, the maximum injection capability corresponds only to the most favorable system condition expected to occur, which is not a valid metric for the actual injection capability, as this rarely occurs. In the past, due to a very limited set of typical generation and storage

[5] The “injection” or output refers to the amount of electric energy produced by the generation facility and injected into the grid.
[6] The term “coincident” refers to the output levels produced at the same time by more than one generator or more than one type of generators.

dispatch patterns associated with the economic dispatch of conventional resources (e.g., coal, gas, and hydro) and use of storage resources such as Cabin Creek, transmission injection capability would typically fall within a narrower range and could be determined with a high level of certainty. However, with increasing levels of weather-dependent resources integrated into the PSCo Balancing Authority Area ("BAA"), the resulting generation and storage dispatch patterns have become increasingly variable. Assigning a single (standalone) injection capability to any location is unrepresentative of the actual capability at that location given that the injection capability range has a wider spread due to the highly variable dispatch patterns associated with wind and solar resources. Determining a maximum injection capability is akin to marking one bookend of the wide range of variable injection capability resulting from myriad combinations of variable loads, generation, and storage dispatch patterns. This is also the reason it is not appropriate to simply add up standalone injection capabilities for purposes of determining the simultaneous injection capability of the transmission system.

The transmission system is interconnected as a network, and generation injection or storage at one location on the system more often than not changes the injection capability at other locations, e.g., generation injections at Pawnee could decrease the generation injection level at Missile Site and vice versa. The generation injection capability values can change when Public Service performs additional transmission studies, whether for clustered Generator Interconnection Requests or for ERP portfolio alternatives, or simply when the projected system conditions change.

Therefore, assigning a fixed injection capability to any location is inappropriate because it does not represent the actual injection capability at that location for all system conditions. The actual injection capability is inherently a moving target that varies with the prevailing system conditions characterized by system load level and economic generation dispatch. In Phase I of the 2021 ERP & CEP, the Company requested a waiver of Rule 3608(c)(III)-(IV). In its Phase I Decision, the Commission granted the requested waiver of provisions regarding injection capability and agreed that providing a fixed injection capability to any location on the system is misleading given the dynamic and variable nature of the Company's system.[7]

Transmission Service Agreements

Public Service is party to a number of transmission service or "wheeling" agreements that are not specifically tied to PPAs. For example, Public Service has a number of retail and wholesale load centers residing within the PRPA, WAPA, and Tri-State transmission systems, and acquires network integration transmission service from each of these utilities pursuant to their open access transmission tariffs ("OATT").

The vast majority of Public Service's owned and purchased resources are located within the Public Service transmission system and have no specific wheeling agreement associated with them. Rather, in accordance with the requirements of FERC, the

[7] Decision No. C22-0459, at ¶468.

transmission function of Public Service maintains a list, posted on its OASIS website, of designated network resources that are delivered to Public Service's native load customers. This list is updated when a new resource has completed the required transmission study processes and is placed in service, and when a PPA terminates or a generator is retired.

Public Service has a long-term firm point-to-point service agreement with the transmission function of Public Service for the purchase of 188 MW of transmission service from the San Juan/Four Corners/Shiprock region to the Craig switchyard. This path is used to purchase capacity and energy at the Four Corners/San Juan marketplace. It is also anticipated that this path will be used to import economic energy from other Western Energy Imbalance Market partners when Public Service joins that market in 2022. This contract terminates on January 31, 2025 and may be renewed in accordance with the OATT.

Public Service also maintains short-term firm and non-firm transmission service agreements with over 30 transmission service providers, pursuant to the providers' OATTs. These agreements are not transaction-specific and have no specified MW quantity or term. Rather, these "umbrella" agreements allow (and are required in order for) Public Service to request and purchase short-term transmission services via the providers' OASIS sites. Such purchased transmission services are used to transmit short-term purchased resources to the Public Service system, or to facilitate off-system sales.

Coordination Agreements

Public Service purchases short-term energy and capacity under two coordination agreements: the Western Systems Power Pool ("WSPP") Agreement and the Northwest Power Pool ("NWPP") Reserve Sharing Program Agreement. The WSPP Agreement represents a marketing pool involving many supplier organizations throughout the United States. Many of Public Service's short-term firm and economy purchases are made under, and pursuant to the terms of, the WSPP Agreement.

Along with participating in the WAPA Balancing Authority, Public Service entered the NWPP Reserve Sharing Program in September 2019. The NWPP Reserve Sharing Program Agreement provides for sharing of contingency operating reserves among interconnected electric utilities operating in the Western Interconnection. There are presently 22 participating Balancing Authorities in the NWPP Reserve Sharing Program. By pooling their contingency reserves, these utilities are able to carry less contingency reserve capacity than if they operated independently. Under the NWPP Reserve Sharing Program Agreement, Public Service can call on and purchase contingency reserves (spinning and non-spinning), and the energy associated with such reserves, when they are activated in response to a sudden system disturbance. Public Service can also purchase emergency assistance under the NWPP Reserve Sharing Program Agreement.

2.6 RELIABILITY PLANNING, RESERVE MARGINS AND CONTINGENCY PLANS

In this Section, the Company provides information regarding its planning reserve margin, system reliability planning and assessment, and contingency plans as required by Rule 3609(a)-(c).

Reliability Planning at Public Service

Public Service strives to provide electric service at all times to our firm load customers. To accomplish this, the Company works to maintain an adequate supply of electric generation to meet the expected maximum demand of our customers (i.e., the "peak" demand or load) for a reasonable set of unforeseen events (power plant outages, higher than expected load, etc.) To maintain service to firm load customers, Public Service utilizes a combination of measures and practices, each focusing on different time horizons—real-time, mid-term, and long-term.

Real-time

Ultimately it is the real-time status of the system that determines whether generation supply is sufficient to maintain service to firm load customers. Real-time in this context refers to the measures and practices the Company employs each day in operating the electric system, including carrying sufficient operating reserves to ensure that ample resources are available to serve load. Operating reserves are generation capacity that is either online and unloaded, i.e., spinning, or that can be brought online and synchronized to the grid in short order.

As a member of the NWPP Reserve Sharing Group, Public Service carries operating reserves in accordance with the NWPP established methodology. Public Service's contingency reserve obligation in the NWPP is dynamic based on several factors, including the size of the largest contingency in the PSCo BAA, and real-time transmission available to deliver reserves from other NWPP members.

As a part of managing the real-time balance between load and generation on the system, the Company continuously monitors the current level of wind generation and ensures that a sufficient level of flexible resources is available to maintain system reliability in the case of a large wind ramping event. The level of flexible resources required for this purpose is a function of the amount of wind generation.

Operating Reserve is a general term used to define the combination of various reserves that are needed to perform in the duty of balancing generation and load. Operating Reserve for Public Service is made up of Contingency Reserve, Regulating Reserve, and Flex Reserve. Contingency Reserve is the reserve maintained to respond to the unplanned trip of generators. Contingency reserve is provided by resources that can respond very quickly to an event, within 10 minutes. Contingency reserves are split between spinning (i.e., connected to the grid) and non-spinning resources. The amount of contingency reserve that is to be carried by the Company is determined by the NWPP.

Regulating Reserve is the reserve maintained to respond to intra-hour changes in load, dispatchable generation, and weather-dependent generation, and it is also comprised of various types of service. The two types of regulating reserve are "fast moving reserve" and "load following reserve." To manage minute-to-minute changes in load, dispatchable generation, and weather-dependent generation on the system, Public Service carries fast-moving regulation reserve. To manage changes over a 10-minute period, the Company carries load following regulation reserve. The Company recently studied the amount of fast moving and load following regulating reserve required to reliably manage its system and has updated its Open Access Transmission Tariff accordingly.

The last type of Operating Reserve that Public Service carries on its system to maintain reliable service to customers is Flex Reserve. Flex Reserve is held on Public Service generating units to address the impacts of large downward ramping events caused by reductions in wind speed within the PSCo BAA. The Company determines the amount of Flex Reserve required to operate reliably with the wind it has, or will have, on its system. The calculation has evolved over time due to the increasing size of the wind generation on the system and our experience of performing efficient, reliable system dispatch with increasing levels of installed wind generation.

Mid-term

To better ensure sufficient resources are available to meet the real-time needs of the system, Public Service evaluates the need for short-term capacity and energy several months in advance of each summer and winter peak season. In the event that this mid-term supply adequacy evaluation determines that the installed or purchased generation for the upcoming summer or winter peak periods are likely insufficient to achieve a desired reserve margin, the Company will pursue purchasing short-term capacity.

Long-term

Long-term activities involve the acquisition of additional generation resources or demand reduction to meet the long-term electric demand projections. The amount of perfect generation capacity in excess of the summer and winter system peak demand is commonly referred to as "planning reserve margin" or "planning reserves." Long-term in this context refers to a future period of up to 10 years (or longer), over which the Company acquires additional generation supply resources through the Commission's ERP process. The reserve margin target used in the long-term planning of the system influences the Company's ability to meet the future, mid-term and, ultimately, the real-time capacity needs of the system. The remaining discussion will focus on the "planning reserve margin" Public Service proposes to employ in the acquisition of future resources in the 2024 JTS.

Reliability Assessment of 2024 JTS Portfolios

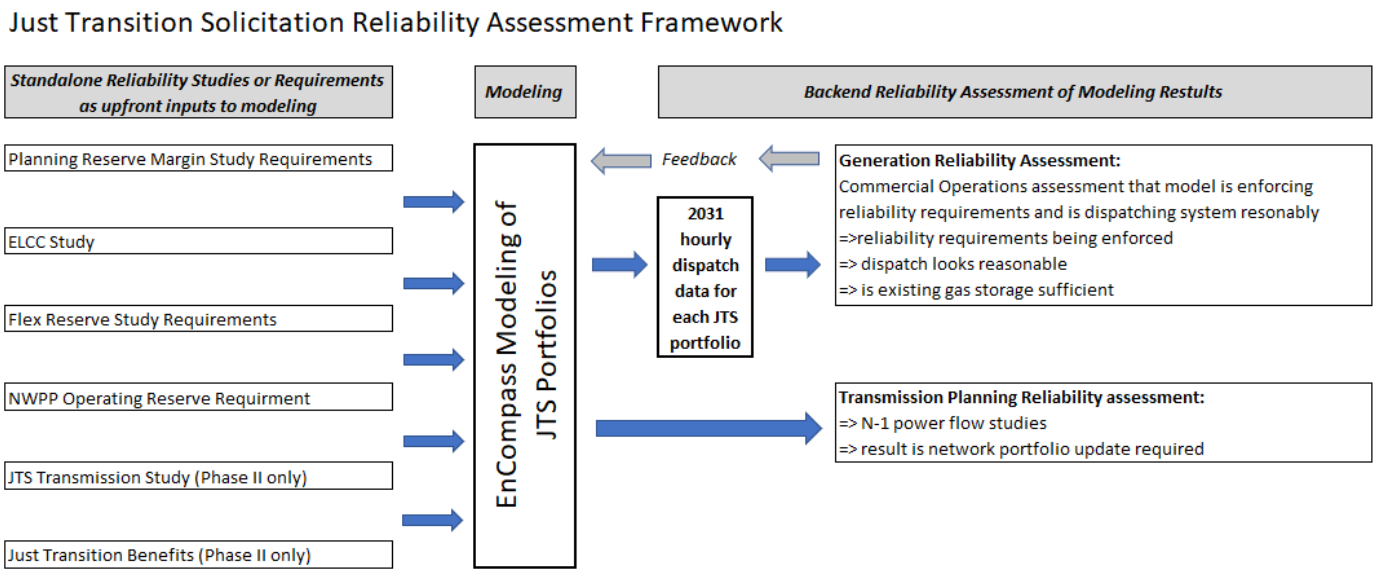
As shown in Figure 2.6-1, system reliability is factored into the development of portfolios in an iterative process that involves inputting various reliability requirements upfront into the EnCompass modeling process, post-modeling reliability review of model output/results, and then adjusting model inputs if needed and then rerunning the adjusted model. Reliability requirements from applicable technical studies, including planning reserve requirements and Effective Load Carrying Capabilities ("ELCC") capacity credit were applied within the EnCompass modeling of all portfolios. In addition to the results of these technical studies, the operating requirements established by the NWPP Reserve Sharing Group were reflected as inputs into the modeling process. Due to timing limitations and the nature of generic modeling for Phase I and the fact that the RECAP reliability model will not be brought in-house until Q4 2024, the post-EnCompass reliability analyses was not conducted on the generic portfolios but will be done for Phase II portfolio development and bid selection.

The post-modeling reliability review process involves reviewing hourly model output for 2031. A team of Company subject matter experts will review the overall generation composition of portfolios from both a generation reliability perspective and a transmission reliability perspective. For the generation reliability review process, the hourly data review process for generation reliability involves an assessment of the 8760 (i.e., the number of hours in a year) hourly model output to determine if the model is properly enforcing planning reserve, flex reserve, and NWPP operating reserve requirements. The review also analyzes whether the current gas supply system would be sufficient to reliably supply the hourly volumes and fluctuations in gas burns that the modeling predicts.

The hourly data review process for real-time transmission reliability also involves an assessment of the 8760 hourly model output. The purpose of the review is to determine if the current and planned transmission system could reliably deliver, in real-time, the output of the generation resources in each portfolio to customer load. However, the Company's transmission team conducted an analysis and planning process to support this 2024 JTS filing involving an assessment of the transmission system impact from representative resource planning portfolios to determine if the planned transmission system expansion could reliably deliver the Company's resource acquisition target, or if not, what potential upgrades might be required. For Phase II, if these reliability reviews identify that a particular reliability input requirement needs adjusting, then the adjustments would be made, the model would be rerun, and the output would be reviewed to see if the adjustment worked as intended. For example, if certain generating units were viewed as contributing more spinning reserves than they should or could, the modeling inputs that define a generating unit's contribution to spin would be adjusted and the model would be rerun. In addition, there are certain aspects of this type of modeling that are a function of the model output and therefore cannot be fully captured through the various upfront inputs into the model. For example, the required transmission upgrades that might be needed to reliably deliver the new generation resources that are added to the system as a result of the optimization cannot be known until after the model is run. In this instance,

the cost for any additional transmission requirements would be a post-modeling addition to the cost of the portfolio.

Figure 2.6-1 Overview of Reliability Assessment Framework



Though the Company doesn't currently use the Transmission Planning Reliability assessment results as a feedback mechanism for portfolio development or modeling, we aspire to do so in the future. The challenge with using transmission analysis as feedback to generation planning is that the two can "chase" each other in a circular process. For example, an optimized capacity expansion plan induces new transmission, which results in a unique, complementary transmission plan. If the Company were to adjust its capacity expansion plan in response to the resultant transmission plan to, say, reduce transmission costs, that would necessitate a new unique transmission plan. We aren't aware of any utilities that have solved this challenge, but we continue to work on how to integrate transmission planning either concurrently or as an effective iterative process into capacity expansion modeling.

Modeling Implementation and Reliability Inputs

Planning Reserve Margin ("PRM")

For purposes of developing the 2024 JTS, each Phase I portfolio included two PRM scenarios for comparison. The first scenario is provided as a comparison to the new methodology and applied an annual PRM construct such as the Company has used in past ERPs, with the PRM within the EnCompass model set to approximately 6% for the peak demand month of the year (July) on a long-term basis. The second scenario utilized the new recommended and preferred seasonal approach, where the PRM inputs were set to approximately 6% for the summer months, and between 8% and 14% for the winter

months.[8] The PRM targets used were a result of the updated study entitled, "*2024 Public Service Company of Colorado Resource Adequacy Study: Analysis of Planning Reserve Margin Requirements & Effective Load Carrying Capability*" ("2024 RA Study") developed by Energy & Environmental Economics, Inc. ("E3") and included as Attachment ZM-1 to the Direct Testimony of Zachary Ming. The probabilistic study evaluated every hour of years 2024 through 2031 for the capacity required to expect no more than 1 loss of load event ("LOLE") in 10 years. The inputs to the study included 44 historical years of weather correlated demand, wind, and solar hourly profiles and the last five years of generator outage profiles to capture the variability in resource availability and demand.

Public Service will implement the results of the 2024 RA Study in the 2024 JTS by acquiring generation resources in Phase II as necessary to achieve, at a minimum, the seasonal reserve margin targets plus the additional reserve in accordance with the Company's wholesale contract with Holy Cross Energy.

In Phase I, each expansion plan was required to meet the reserve margin as a minimum threshold requirement in both annual and seasonal scenarios. As part of its seasonal PRM setting, EnCompass only evaluates January–March to ensure Winter reserve margins are met. However, in the 2024 RA Study, the months where the highest risk for loss of load was observed were December through February. To ensure a complete winter season was properly planned for, if the max peak load for a winter season occurred in December, that peak was used to manually replace the higher peak load value of either January or February. For the years prior to 2028 where the Company could not reasonably expect to acquire resources in the JTS, a "generic short-term seasonal purchase" was included to cover any MW required to meet the reserve margin target, and the model added generic resources on a long-term basis to meet the reserve margin targets in 2028 through 2031.

Effective Load Carrying Capability

For resource planning purposes, different generation technologies provide different levels of their nameplate generation capacity rating toward reliably serving customer load. ELCC is a measure of how much of a resource's nameplate capacity should be included on the Company's load and resources table ("L&R table"). As part of the 2024 RA Study, all existing and planned resources that could either contribute towards serving load or reducing load were evaluated to determine the ELCCs that would be used in the 2024 JTS. New to this study, and recommended for adoption by the Company and E3, thermal resources and demand response programs are also evaluated and given ELCC values that indicate the reliability benefits they create. These resources will be counted on the resources side of the L&R tables in accordance with these ELCCs. Thus, in the new methodology all resources are treated equally, regardless of type.

[8] The Annual PRM setpoint ranges from 5.8 to 6.1 percent, while the Summer PRM setpoint ranges from 6.3 to 6.4 percent. The Winter PRM setpoint experiences the most change year over year, as it grows from 9 percent in 2025 to 13.3 percent in 2031. Additionally, the actual months used for planning purposes and shown in the L&R are Winter: December – February; Summer: June – August.

E3 also developed marginal ELCC curves that would be applied to determine the capacity contribution of future generic resources (or bid resources in Phase II) in the model. For further discussion on how each resource was modeled and studied, please see the 2024 RA Study provided as Attachment ZM-1 to the Direct Testimony of Zachary Ming.

Flex Reserve

Flex Reserve (wind driven) and Regulation (wind and solar driven) ancillary service requirements are directly related to the amount of new wind and solar added in the expansion plan. Studies that develop required values for these services were developed for the 2021 ERP and have been determined to still be suitable for the 2024 JTS and did not require updating. Thus, the prior Flex Reserve and Regulation assumptions used for the 2021 ERP will be used for the 2024 JTS. The Flex Reserve Study prepared in 2020 and approved in Phase I of the 2021 ERP & CEP is provided as Appendix E.

Regulating Reserve is the reserve maintained to manage short-term uncertainty and variability in load and solar generation output. The two types of Regulating Reserve are "fast moving reserve" and "load following reserve." Public Service carries fast-moving regulation reserve to manage minute-to-minute changes in load and solar generation output on the system. To manage changes over a 10-minute period, the Company carries load following regulation reserve. Regulating Reserve can be provided by the unloaded portion of dispatchable generation that is synchronized to the grid and is not being used to provide Contingency Reserve or Flex Reserve. Regulating Reserve is constantly cycling back and forth between a reserve state and deployment as energy. For this reason, energy limited resources such as battery energy storage and demand response programs are not used for Regulating Reserve.

The ancillary service requirements are pre-run inputs into the model and are not able to be dynamically resized within the model as the expansion plan is being developed. Thus, to fully represent each specific plan, an iterative approach to sequentially develop a plan, resize the Flex and Regulation, and repeat until they match/converge is required.

Given the generic nature of the Phase I plans, as well as the time constraints required to do iterations with the large number of Phase I scenarios and sensitivities, this process was not fully executed for Phase I. During the preliminary runs completed by the Company leading up to the final modeling, a relatively consistent and clear pattern of generic additions emerged. The Company developed two different "requirements" shapes through 2050 based on these expansion plan results and applied them to the appropriate scenarios for Phase I. Upon inspection of the final plans, these proved to be reasonably consistent and valid for the final modeling results. The two versions of the requirements were \$0/ton CO_2 Portfolios and SCC CO_2 Portfolios.

Operating Reserves

The real-time status of the Company's electric system determines whether supply is sufficient to maintain electric service to firm load customers. Real-time in this context refers to the measures and practices the Company employs each day in operating the electric system which entails carrying sufficient Operating Reserve to ensure that ample generating resources are available to accommodate total firm load, higher than expected firm load, changes in firm load (minute to minute and hour to hour), unexpected outages of generating units (forced outages), and variability in the output of renewable resources. These real-time measures and practices focus on maintaining sufficient levels of Operating Reserve.

Operating Reserve is a term used to define the combination of various reserves that are needed to perform the duty of continuously balancing generation and load throughout the day. Operating Reserve for Public Service is made up of Contingency Reserve, Regulating Reserve, and Flex Reserve.

Contingency Reserve is the reserve maintained to respond to the unplanned trip of generators or transmission elements and is provided by resources that can respond very quickly to an event, within 10 minutes. Contingency Reserve is split between spinning (i.e., connected to the grid) and non-spinning resources. The amount of Contingency Reserve that is required to be carried by the Company is determined by NWPP. In general, NWPP requires members to maintain Contingency Reserve equal to the greater of 3% of the balancing area load plus 3% of the balancing area generation or the most severe single contingency ("MSSC") with the additional requirement that at least half of the requirement be provided by spinning reserves. The remainder of the Contingency Reserve requirement not provided by spinning reserves may be provided by non-synchronized resources available within 10-minutes. The MSSC for Public Service will typically be either the Rush Creek Gen-Tie or the 750 MW Comanche 3 unit. The portion of any resource used to meet Contingency Reserve cannot be used to meet Regulating Reserve or Flex Reserve.

The Operating Reserves requirement is set by the NWPP and is an hourly value that is determined by a complex formula including Public Service hourly load and generation, the remainder of the balancing authority's hourly load and generation, hourly real-time available transmission support via the TOT tie lines, and the most severe single contingency ("MSSC") on the system, which currently is typically either Comanche 3 or the flow on the Rush Creek gen-tie line. To develop a reasonable proxy of this requirement, static hourly curves were developed for each of these variables from the associated model input data and were used to develop an hourly proxy shape for total operating reserve requirements using the actual NWPP formula. Within the model, one half (50%) of the operating reserves were required to be carried by spinning reserves that could be carried by online resources or 10-minute responsive quick-start units.

Contingency Plan

Rule 3609 requires the Company to develop contingency plans for the RAP given actual circumstances may differ from the most likely estimate of future resource needs; and provide, under seal, a description of its proposed contingency plans for the acquisition of additional resources if actual circumstances deviate from the most likely estimate of future resource needs developed pursuant to Rule 3610 or, replacement resources in the event that resources are not developed in accordance with a Commission-approved plan under Rule 3617.

Public Service recognizes that matching electric power supply with customer demand will not always proceed according to plan. Problems can arise as a result of delays in the in-service dates of new generation facilities, contract negotiations with power suppliers can breakdown, and unanticipated increases in customer demand can arise that Public Service is obligated to serve. While it is impossible to anticipate everything that can occur in the resource acquisition process, we can anticipate the more common situations and develop plans to address them.

In the discussion below, the Company describes what it believes to be the most likely situations the Company might face in the resource acquisition process and identifies contingency alternatives available to address them. The discussion focuses on events or situations that create the potential for a capacity shortfall if corrective action is not taken.

Contingency Events

Public Service anticipates that the more relevant and probable contingency events will include, but are not limited to:

1. Failed contract negotiations with winning bidders
    a. Bidders withdrawing proposal
    b. Bidders seeking revised terms and/or prices from those in their bid
2. Project development delays or cancellation
3. Transmission development delays
4. Higher than anticipated customer demand

Contingency Plan Options

The following is a list of options available to Public Service to remedy any unanticipated resource shortfall:

1. Initiate negotiations with other / replacement backup bidder(s)
2. Activate pre-construction development assets (“PCDA”) as discussed below
3. Accelerate the in-service date of other selected projects
4. Implement interim Load Management / Customer generation plans
5. Purchase short-term capacity from off-system, existing generation
6. Acquire incremental Distributed Energy Resources (including demand-side management resources)

7. Issue a targeted RFP to replace a selected project that has failed
8. Issue additional non-targeted RFP(s) to satisfy anticipated shortfalls
9. Construct and own additional new generation facilities
10. Arrange temporary generation
11. Modify contracts with existing power suppliers
12. Sole source with an IPP to construct additional generation
13. Reduce reserve margin

Critical Factors

Two critical factors dictate whether a corrective action provides a viable solution for a particular contingency event. These factors are:

1. The magnitude of the potential resource shortfall; and
2. The timing associated with the potential capacity shortfall – both the lead-time to the contingency and the duration of the event.

The magnitude of an anticipated capacity shortfall dictates the available options Public Service can pursue. For example, a capacity shortfall of 50-100 MW might be addressed through contracting short-term purchases from off-system existing generation. Short-term capacity purchases would likely be ineffective in addressing a larger shortfall, such as 500 MW for example.

Similarly, the timing of an anticipated capacity shortfall dictates the number of available options Public Service can pursue. Timing in this case includes both the duration of the shortfall and when it is expected to occur. Capacity shortfalls projected to occur within a year for example would likely exclude the option of constructing new generation and transmission facilities. By contrast, a capacity shortfall projected to occur several years in the future could be addressed through a variety of actions including new construction, initiating negotiations with other bidders, or issuing a targeted RFP.

Likewise, a delay of a new generation resource or of the transmission needed for a new resource might best be addressed by a temporary or interim solution, like temporary generation facilities, short-term purchases, or interim load management, as opposed to the permanent addition of another new generation project or new Company-constructed and owned generation facilities—unless there were a long-term need for additional resources.

Corrective Actions

In the event Public Service faces a capacity shortfall situation, the appropriate course of action will depend largely on the specifics of the shortfall itself (i.e., magnitude and timing), as well as a variety of other factors (e.g., market conditions and other acquisition activities underway). As such, Public Service will always need to exercise judgment as to how to proceed when deciding what corrective action to pursue. For this reason, the Public Service contingency plan reflects a large degree of flexibility in how the Company plans

to address various contingencies. Table 2.6-1 lists several possible approaches for addressing contingencies that might require corrective action over the RAP. This hierarchy depends on how long before the event Public Service becomes aware of the contingency, the expected duration of the contingency (e.g., a delay versus the permanent loss of a planned resource), and the magnitude of the contingency.

Table 2.6-1 Hierarchy of Contingency Plan Alternatives

1	Activate PCDA assets	In the event of a project failure, the Company would replace the failed project with a like-for-like project from the PCDA portfolio. For an IPP-for-IPP replacement, the Company would file a notice with the Commission of activation. For any utility-owned replacement, the Company would file a notice with the Commission including a robust alternatives analysis demonstrating the utility-owed like-for-like replacement was the optimal and prudent solution.
2	Initiate negotiations with other / replacement backup bidder(s)	If the contingency becomes known before Public Service has released bidders from their obligation, Public Service would use this corrective action. This corrective action is most appropriate for replacing 1st winning bids that drop out soon after selection or do not reach successful contract completion.
3	Accelerate the in-service date of other selected projects	If the contingency becomes known sufficiently ahead of time, negotiate an earlier in-service date for a resource planned for later in the acquisition period. This corrective action is most appropriate for a one to two-year delay in another resource.
4	Implement interim Load Management / Customer generation plans	Similar to the installation of temporary generation, this measure can be implemented in a relatively short lead-time, e.g. within 6 months, and is well suited to address resource delays.
5	Purchase short-term capacity from off-system, existing generation	Save for “late breaking” contingencies for which there might not be time to use one of the following corrective actions.
6	Acquire incremental Distributed Energy Resources (including DSM)	If the contingency becomes known in time, the Company could acquiring incremental Distributed Energy Resources, such as additional demand response resources. This could take 12-36 months.
7	Issue targeted RFP to replace a selected project that has failed	A targeted RFP for a particular technology similar to the failed bid(s) could be issued for expected shortfalls
8	Issue additional non-targeted RFP(s) to satisfy anticipated shortfalls	A non-targeted RFP open to various technology types could be issued for expected shortfalls
9	Construct and own additional new generation facilities	If the contingency becomes known in time for Public Service to build its own facility, Public Service will self-build a facility to cover the contingency through the use of the back-up bid that will be filed with the Commission at the time the bids for the RFP are due to be submitted to the Company.
10	Arrange temporary generation	The Company or an IPP can implement this measure with somewhat less lead-time than the installation of new permanent generation and it is well suited to cover a generation project or transmission delay that may last a year or possibly two.
11	Modify contracts with existing power suppliers	Ascertain if existing contracts can supply more capacity from facility
12	Sole source with an IPP to construct additional generation	This option could substitute for Public Service building its back-up bid if time does not permit the Company to complete the necessary construction in a timely manner. Effectively, Public Service would approach an IPP with whom it has had a good working relationship and sole source a new supply either from an existing facility or possibly an expansion of an existing facility.
13	Reduce reserve margin	If the contingency became known too late to add new resources in time and insufficient short-term purchases were available to cover the contingency, Public Service could operate with a reduced planning reserve margin but with the required operating reserve margin for a summer season until one or a combination of the other corrective actions could be put into place.

Public Service and other Xcel Energy Inc. electric utility operating companies have successfully applied many of these contingency actions in the past. Xcel Energy Inc.'s other utility operating companies also have experience with many of these measures and Public Service can draw upon a wide range of resources, experience, and capabilities in order to respond in the most appropriate way to contingencies that might develop during the RAP for the 2021 ERP & CEP.

Pre-Construction Development Assets

The Company's intends to implement a pre-construction development asset ("PCDA") contingency option intended to provide flexibility to quickly develop generation and capacity resources to address near-term system uncertainty caused by project failures and system load growth. PCDA will be a means to acquire but defer construction of some generation and capacity resources in the Phase II process. The concept essentially provides a low-cost option that limits customer cost exposure while supporting developers with some assurance their costs associated with developing a project will be returned.

The Company's proposed PCDA policy generally applies to any project regardless of technology or ownership structure (i.e., IPP or Company-owned) and is designed to place both types of bidders on as level a playing field as possible. The Company will allow bidders, IPPs or self-builds, to select the option to treat their bid as a PCDA. As part of the Phase II report process, the Company will review all PCDA projects and develop a portfolio of projects it believes warrant PCDA treatment, then present that portfolio for Commission review. This portfolio would be supplemental to the Company's preferred and/or alternative portfolios, as well as the backup bids, not in lieu of these portfolios. Upon Commission approval of a PCDA project portfolio, the Company would then engage in negotiations with IPPs to execute purchase power agreements, just as it would typically do with an approved IPP project, and/or the Company would file a CPCN as necessary for any self-build or build-transfer PCDA projects.

In addition to the minimum bid requirements outlined in the RFP, including pricing information, construction schedules, and other detailed requirements, the Company will require bidders who choose the PCDA option to provide a detailed milestone payment schedule with an explanation of why those milestone payments are necessary. The milestone payment schedule must detail the amount and frequency of payments the bidder requires in order to keep its bid viable for construction. Other requirements include the anticipated in-service date ("ISD") and a discussion of the time frame for a project to achieve the ISD from "shovel-ready" if the contingency plan is triggered, how the bidder will confirm milestone achievement to the Company consistent with the milestone schedule in the bid narrative. For independent power producer projects that would result in a PPA, bidders must agree to hold the PPA rate through the end of 2031 and execute a binding term sheet with the Company.

In addition to the per project milestone payment cap, there are three other customer protections. First, should a project enter into a PCDA agreement and later withdraw for

any reason outside of Force Majeure conditions, the bidder would be required to refund any milestone payments. Second, any IPP bid must enter into a contract with Public Service preserving the project exclusively for Public Service for the term of the PCDA contract. Third, any IPP must enter into a contract prior to receiving any funds while for any self-build or build-own-transfer ("BOT") project, the Company is required to report on the status of each project in the quarterly Electric Commodity Adjustment ("ECA") filing. In total, these provisions ensure that any PCDA project is exclusively retained for the benefit of Public Service customers and ensures that bidders cannot use the milestone payments to develop the project and then solicit alternative off takers. For utility-owned projects, continued reporting through quarterly ECA filings ensures the Commission and stakeholders have an understanding of how milestone payments are being invested and that projects are being appropriately managed in case of future need.

To activate PCDA projects the Company would follow the same process approved in the 2021 ERP & CEP. Upon project failure, the Company would first look to replace the failed project with a like-for-like project from the PCDA portfolio. For an IPP-for-IPP replacement, the Company would file a notice with the Commission of activation. For any utility-owned replacement, the Company would file a notice with the Commission including a robust alternatives analysis demonstrating the utility-owed like-for-like replacement was the optimal and prudent solution. For any project not activated during the contractual period, the project would be released and free to either find an alternative off-taker or rebid into a future Phase II solicitation. The bidder would not be required to return any milestone payments.

2.7 ENERGY STORAGE BENEFITS, OPERATIONS, AND MODELING

In this Section, the Company discusses energy storage benefits, operations, and modeling and provides information required by Rule 3604(m) and Rule 3610(b)(III).

Rule 3604(m) requires the Company's ERP to include:

> Modeling assumptions and analytical methodology proposed to assess the costs and benefits of energy storage systems including, but not limited to: integration of intermittent resources; improvement of reliability; reduction in the need for increased generation facilities to meet periods of peak demand; and avoidance, reduction, or deferral of investments.

In assessing its need to acquire additional resources, Rule 3610(b)(III) requires the Company to:

> Consider the benefits energy storage systems may provide to increase integration of intermittent resources, improve reliability; reduce the need for increased generation facilities to meet periods of peak demand; and avoid, reduce, or defer investments.

The discussion below describes:

- The "storage value stack";
- Quantification of specific value stack values through study reports or EnCompass modeling procedures;
- Existing and planned storage resources in the Company's portfolio;
- The Company's preferred storage types; and
- How storage resources will be evaluated in the Phase II competitive acquisition.

Energy Storage Devices

At a most basic level, energy storage devices are useful for moving energy from one time period to another. However, as this movement of energy across time comes with efficiency losses, the addition of energy storage to a system is net energy load added to the system. Cost-effective implementations of energy storage require putting the right type of device, with the right mix of power and energy and the right performance characteristics, in the correct location.

For purposes of the Company's ERP filing and ultimate resource acquisition, storage systems are restricted to those that can serve as a generation/supply-side resource, with the exception of Aggregated Distributed Energy Resources ("ADER"). A useful way to categorize the different types of storage devices as generation resources is through an examination of whether they are designed for power (large MW, but small MWh) or energy

(large MW, large MWh) applications.[9] Thus, a storage device's energy to power ratio (which equals its duration) is a useful way to categorize storage devices and track their potential ability to serve the "storage value stack" as described below. In addition, for chemical storage devices (e.g., batteries and reversible fuel cells), the specific cell chemistry has a large impact on the device's performance characteristics.

Storage Value Stack

As indicated above, storage systems for this ERP are restricted to those that can serve as a generation or load modifying resource. Thus, the following are not evaluated: (1) thermal storage resources that might convert electrical energy into thermal energy for sensible heating or cooling purposes, and (2) seasonal fuel storage, such as the storage of natural gas during non-winter months for winter heating usage. Generally, the type of storage contemplated converts electrical energy to some other form (e.g., thermal, mechanical, chemical) and then eventually converts it back into electrical energy to serve electrical system requirements. However, other storage mechanisms can store primary energy in some form other than electricity and then ultimately convert it into electrical energy (e.g., solar thermal power plants with embedded thermal storage). Such resources will be evaluated for acquisition.

System beneficial uses of energy storage devices (i.e., uses that make up a potential storage value stack) can be categorized into four broad categories:[10]

1. Bulk Energy Services
    a. Energy Arbitrage
        i. Weather-Dependent Generation Curtailment Reduction
    b. Generation Capacity Credit
    c. Dispatchability
2. Ancillary Services
    a. Operating Reserves
        i. Regulating
            1. Fast-moving
            2. Following
        ii. Contingency
            1. Spinning
            2. Supplemental (Non-spinning)
        iii. Flex
    b. Voltage Support
    c. Black Start
3. Transmission Infrastructure Services
    a. Upgrade Deferral

[9] Power is the rate at which energy can be delivered; typically measured in MW. Energy, for a storage device, is the product of the device's power rating (MW) times the device's duration (hrs); measured in MWh.

[10] The categorization and description of the beneficial uses of energy storage devices generally follows that from Sandia Report SAND2015-1002, "DOE/EPRI Electricity Storage Handbook in Collaboration with NRECA", 2015. Available at: https://www.sandia.gov/ess-ssl/publications/SAND2015-1002.pdf.

   b. Congestion Relief
4. Distribution Infrastructure Services
   a. Upgrade Deferral
   b. Voltage Support

Below, the Company describes each of these services.

1.a. – Energy Arbitrage

Storage devices can be used to store electricity ("charging") when costs are low and then deliver that energy back to the electric grid ("discharging") when costs and/or needs for electricity are high. Storage devices with high round-trip efficiency and low variable O&M costs provide the highest potential energy arbitrage benefits.

1.a.i. - Intermittent Generation Curtailment Reduction

A subset of Energy Arbitrage occurs when "excess" intermittent, or weather-dependent, generation is available relative to load; normally such "excess" weather-dependent generation is curtailed. Using a storage device in such situations allows a portion of the renewable generation that would otherwise be curtailed to be delivered to load at a later time.[11]

1.b. – Generation Capacity Credit

For long-term resource planning purposes, energy-limited resources like storage receive less than their nameplate discharge capacity on a loads and resources table; the ability of a storage device to reliably serve long-term forecasted loads can be measured through an ELCC methodology. In general, the storage device's duration (calculated as maximum MWh discharge energy divided by maximum MW discharge rate) and inclusion of weather-dependent generation and other energy-limited resources in the resource portfolio are the primary determinates of ELCC.

For daily operations, the generation capacity credit afforded a storage device is determined through the unit-commit and dispatch process and is more closely related to the shape of the forecasted daily load peak and the forecasted state of charge of the storage device prior to the forecasted peak.

1.c. – Dispatchability

Inherent to the concept of Bulk Energy Services is the ability for a utility to control the charging/discharging capabilities of the storage device, that is, to be able to dispatch the device in response to changes in net load.

[11] Only a portion of the otherwise curtailed weather-dependent generation can be delivered to load due to inefficiencies in charging, storing, and discharging storage devices.

2.a.i. – Regulating Reserves

Regulation service is associated with managing the flows of energy between control areas and addressing short-term fluctuations in demand within a control area. Its goals are to maintain grid frequency and meet NERC reliability standards. Regulation service is typically provided through regulating reserves. Regulating reserves have two separate components: (1) a fast-moving component that addresses minute-to-minute uncertainty in net load, and (2) a following component that addresses uncertainty at the 10-minute level (i.e., load following).

2.a.ii. – Contingency Reserves

Contingency reserves are generally intended to compensate for generation or transmission outages. Spinning reserves must be online (i.e. synchronized to grid frequency) but unloaded and able to respond within 10 minutes. Supplemental reserves may be offline but must be able to respond within 10 minutes; interruptible loads can also be used for supplemental reserve purposes if they can respond within 10 minutes.

2.a.iii. – Flex Reserves

Flex reserves are an additional operating reserve the Company developed to ensure its compliance with NERC reliability standards given the levels of wind generation in its portfolio. Flex reserves have three components which include: (1) additional regulating reserves from non-energy-limited resources, (2) any 10-minute responsive resources, and (3) any 30-minute responsive resources.

2.b. – Voltage Support

To manage reactance at the transmission grid level, system operators need voltage support resources to offset reactive effects of grid elements so that the transmission system can be operated in a stable manner. Cost-effective voltage support device usage is site-specific.

2.c – Black Start

In the event of a catastrophic failure of the grid, active reserves of power and energy within the grid are needed to energize transmission lines and provide station power to bring power plants back online. Black start devices are site-specific.

3.a – Transmission Upgrade Deferral

Depending upon circumstances, a relatively small MW and MWh of storage could delay the need for a specific transmission system capital investment. Cost-effective transmission upgrade deferrals are site- and situation-specific.

3.b. – Transmission Congestion Relief (Energy Device)

Depending upon circumstances, a sufficient MW and MWh of storage could be placed on either side of a congested transmission element and allow otherwise-curtailed economic generation to be delivered to load. Cost-effective transmission congestion relief opportunities are site- and situation-specific.

4.a – Distribution Upgrade Deferral

Depending upon circumstances, a relatively small MW and MWh of storage could delay the need for a specific distribution system capital investment. Cost-effective distribution upgrade deferrals are site- and situation-specific.

4.b – Distribution Voltage Support

Similar to transmission-sited voltage support, voltage support devices can be required to offset reactive loads on the distribution system. Cost-effective voltage support device usage is site-specific.

Caveats to the Storage Value Stack

In the development of cost-effective portfolios that reliably serve the Company's customers, it is important to acknowledge that any generation resources can be used (and are currently used) to meet almost all of the above services. That is, the concept of a "value stack" does not apply only to storage devices; it applies to all generation resources. The one service listed above that can only be served by energy storage is energy arbitrage.

No resource can provide all of the above values at the same time. However, over the course of a year, prudent charge and discharge decisions should allow storage resources to provide several of the services listed above at some point during the year, including:

- Energy Arbitrage;
- Generation Capacity;
- Weather-Dependent Generation Integration; and
- Reserves (under certain specific circumstances).

Some of the potential storage value services shown above are mutually exclusive. For example, Black Start capability must be available with no advance notice in the event of a total grid failure. Thus, a storage device (or the portion of a storage device)[12] dedicated to Black Start service cannot be used for any other service at any time. Similarly, a resource can only be used to provide a single Operating Reserve at a time.

[12] When the Company carries Black Start service on its Cabin Creek pumped hydro facility, it maintains a dedicated volume of water in the upper reservoir. The balance of the water in the upper reservoir is available for dispatch.

Energy storage, when charged with carbon-free generation, can serve many of these grid services without carbon emissions. However, the same can be true of any thermal generation resource; if the fuel consumed by a thermal generation resource is carbon-free or carbon neutral, those units can also serve these grid services without carbon emissions. If energy storage devices are charged with carbon emitting generation, then it is possible for the use of energy storage to result in a net increase in carbon emissions.[13]

It is also important to realize that the need for many of these services is limited. The incremental energy service value applied to incremental resources experiences diminishing returns; that is, the first tranches of incremental storage provide higher value than later tranches. The Company will have approximately 575 MW of 4-5 hour duration storage in its portfolio by the end of 2022, and the existence of these storage resources reduces the incremental value provided by incremental storage resources.

Company Storage Preferences

The following requirements are to be met for both PPA and Ownership bids regarding storage bids, as well as complying with the other terms of the model PPA/model Term Sheet and Technical Specifications.

- As a minimum use case, designs should assume 275 full equivalent (100%) depth of discharge cycles per year.
- The minimum storage duration of the battery shall be 4 hours.
- Battery augmentation will not be required but is strongly preferred by the Company. Whether or not augmentation is included in the bid, a degradation curve must be provided for all bids. The degradation curve must show battery capacity, AC useable capacity in MWh at the point of delivery (not at the battery itself), and the round-trip efficiency of the battery in each year.
- Batteries must be sufficiently designed to provide full-rated power for the as-bid duration. This means that a four-hour 200 MW battery must deliver 200 MW for 4 consecutive hours, totaling 800 MWh at the point of delivery. If it takes longer than 4 hours to deliver 800 MWh, the battery does not meet this requirement and the as-bid duration needs to be modified to reflect the actual capability of the project. All bidders will be subject to performance testing according to the terms set in the Ownership and PPA terms. Should a project fail to deliver the full rated power in the as bid storage duration, the project will be allowed to begin commercial operation, but will need to begin augmentation to remedy the performance shortfall within a set number of days.

[13] Whether or not the use of energy storage to meet a grid service results in a net increase in carbon emissions is dependent upon the carbon intensity of the charging generation, the round trip efficiency of the energy storage device, and the carbon intensity of the avoided generation resource that would otherwise have been used to meet the need.

Valuing the Value Stack

Quantification of Bulk Energy and Ancillary Services value for storage devices is conducted within the EnCompass model of the Company's electric system and the balance of the resource portfolio. Several of the services are quantified completely within the model (e.g., Energy Arbitrage and Operating Reserves) based on the impact that the charging and discharging of storage devices during certain hours and the assignment of reserves during other hours have on the dispatch of other dispatchable generators in the portfolio. Storage resources are assigned an ELCC according to the technology specifications, and the EnCompass model organically determines whether they are a cost-effective means of meeting the Planning Reserve Margin, and in what amounts.

Those values in the list that are site-specific (i.e., Voltage Support, Black Start, Transmission, and Distribution Infrastructure Services) are not calculated within the EnCompass model; such values would need to be quantified outside the model based on an ad hoc calculation given the specific issues on the local grid intended to be addressed. That is, if a specific distribution system upgrade is targeted for deferral/avoidance through the use of a storage device, the exact nature of the distribution issue needs to be evaluated to determine whether a storage device is a potential solution.

Table 2.7-1 indicates which values in the potential storage value stack are captured within the EnCompass model and which would need to be calculated outside the model, if applicable to a proposed project. The generic storage device in Phase I was assumed to be not capable of providing regulation services, but if a specific bid is submitted in Phase II that is designed to be capable of providing this service, it will be included in the model.

Table 2.7-1 Storage Resource Values Captured Within the EnCompass Model

Potential Energy Device Storage Value	Captured within EnCompass Model
Bulk Energy Services	
Energy Arbitrage	Yes
Weather-Dependent Generation Curtailment Reduction	Yes
Generation Capacity Credit[1]	Yes
Dispatchability	Yes
Ancillary Services	
Operating Reserves:	
Regulating - Fast-Moving	Yes
Regulating - Following	Yes
Contingency - Spinning	Yes
Contingency - Supplemental	Yes
Flex - 10-Minute Responsive	Yes
Flex - 30-Minute Responsive	Yes
Voltage Support[2]	No
Black Start[2]	No
Transmission Infrastructure Services	
Upgrade Deferral[2]	Partially
Congestion Relief[2]	Partially
Distribution Infrastructure Services	
Upgrade Deferral[2]	No
Voltage Support[2]	No
Other	
Carbon Emission Avoidance[3]	Yes

Notes:
1) Subject to ELCC evaluation
2) Site-specific
3) With carbon cap enforced

Sub-Hourly Calculation of Storage Values

The EnCompass model values certain storage values that can be categorized as “sub-hourly;” these include all the Ancillary Services shown in Table 2.7-1. As portfolio selection and costing in EnCompass will be conducted with an hourly representation of load and generation, other unidentified sub-hourly storage values are not captured.

Modeling Process for Renewable Hybrid Facilities

In the Phase I modeling, the Company modeled generic storage as a standalone resource to simplify the modeling. The Company included a percent reduction from the NREL Annual Technology Baseline ("NREL ATB") costs to represent the impact of the current federal investment tax credit ("ITC"). The changes to the tax credit requirements for hybrid storage enacted in the Inflation Reduction Act ("IRA") eliminated the restrictions on grid charging, making this modeling simplification justified.

In Phase II, bid proposals will be modeled in accordance with the actual economics and operational parameters of the specific proposed bids.

2.8 ASSESSMENT OF NEED FOR ADDITIONAL RESOURCES

In this Section, the Company provides information regarding its assessment of the need for additional resources as required by Rule 3610. Rule 3610(a) requires the Company to assess the need to acquire additional resources during the RAP by comparing the electric energy and demand forecasts developed pursuant to Rule 3606 with the existing level of resources developed pursuant to Rule 3607 and planning reserve margins developed pursuant to Rule 3609. Additionally, as discussed throughout the Company's 2024 JTS, the need for resources is driven by the planned retirement of Comanche 3 no later than January 1, 2031, the progress the resources make toward statewide emissions reduction goals of House Bill 19-1261, and the just transition related benefits and other impacts that the portfolios provide to the Pueblo and Routt County communities, and the State of Colorado.

Renewable Energy Standard Resources

In assessing its need to acquire additional resources, Rule 3610(b)(I) requires the Company to determine the additional eligible energy resources, if any, the Company will need to acquire to comply with the Commission's Renewable Energy Standard ("RES") rules. The RES requires the Company to generate 30 percent of electric retail sales from renewable resources beginning in 2020 and each compliance year thereafter, with three percent of that energy coming from renewable distributed generation. Public Service remains well-positioned to meet the Colorado RES going forward. As a result, acquisition of renewable energy resources in this 2024 JTS is driven by the economic value of renewable energy and its significant contribution toward achieving clean energy targets as opposed to the strict need to comply with the minimum requirements of the RES.

Demand-Side Resources

In assessing its need to acquire additional resources, Rule 3610(b)(II) requires the Company to take into account the demand-side resources it must acquire to meet the energy savings and peak demand reduction goals established under § 40-3.2-104, C.R.S. To that end, the Commission shall permit the utility to implement cost-effective demand-side resources to reduce the need for additional resources that would otherwise be met through a competitive acquisition process pursuant to Rule 3611.

Benefits of Energy Storage Systems

In assessing its need to acquire additional resources, Rule 3610(b)(III) requires the Company to consider the benefits energy storage systems may provide to increase integration of intermittent resources, improve reliability, reduce the need for increased generation facilities to meet periods of peak demand, and avoid, reduce, or defer investments. The Company is committed to energy storage systems, and has acquired storage resources in the last two All-Source RFPs, as part of the 2016 ERP and 2021 ERP.

Dispatchable Generation Resources

As discussed throughout the 2024 JTS filing, the Company emphasizes the continued need to maintain some level of dispatchable generation resources as part of the Company's generation supply fleet. In this context, the term "dispatchable generation resources" refers to resources that system operators can start and ramp up or down anytime, day or night, regardless of local meteorological conditions, and can operate continuously for multiple days.

The Company needs to ensure it has sufficient dispatchable resources to serve customers when renewable generation is not available for system reliability. The Company will assess the need for these types of resources through application of the PRM and ELCC values into the EnCompass computer model and application of reliability testing to portfolios (e.g., round-trip modeling). There is no requirement for a specific level of firm dispatchable resources, it is a function of creating reliable portfolios.

Aggregated Distributed Energy Resources

Aggregated Distributed Energy Resources ("ADER") (also commonly termed Virtual Power Plants or "VPPs") that integrate various distributed energy resources, including residential or commercial-sized batteries, rooftop/behind-the-meter solar panels, electric vehicles, water heaters, smart thermostats, and other load devices are encouraged to bid into the Phase II RFP. These resources can balance electricity supply and demand while offering grid services similar to traditional power plants. Additionally, ADER should be able to set operating parameters for dispatch, ramp rates up or down, deliver multiple grid services, and dispatch against a specific capacity target throughout the year.

Any proposed ADER programs shall not cannibalize existing participants or capacity from current demand response ("DR") or energy efficiency ("EE") programs in PSCo and are required to utilize incremental resources that do not already contribute their benefits to the PSCo system. All ADER programs must only leverage capacity from current Xcel Energy PSCo customers located within the Company's service territory.

Proposed ADER programs shall clearly define the total resource capacity available based on the expected impact the system will realize. For example, an ADER program leveraging managed electric vehicle ("EV") charging shall not report total capacity for every forecasted EV enrollment, but instead report expected capacity applying discounts for available EVs plugged in, EVs with enough capacity to participate in given events, etc.

ADER programs must also address seasonal capacity changes to show when they are available to provide system benefits throughout the calendar year. For example, an ADER program leveraging cooling loads will not show available capacity during the winter season.

2.9 LOAD AND RESOURCE ASSESSMENT

Reliability/Capacity Need Assessment

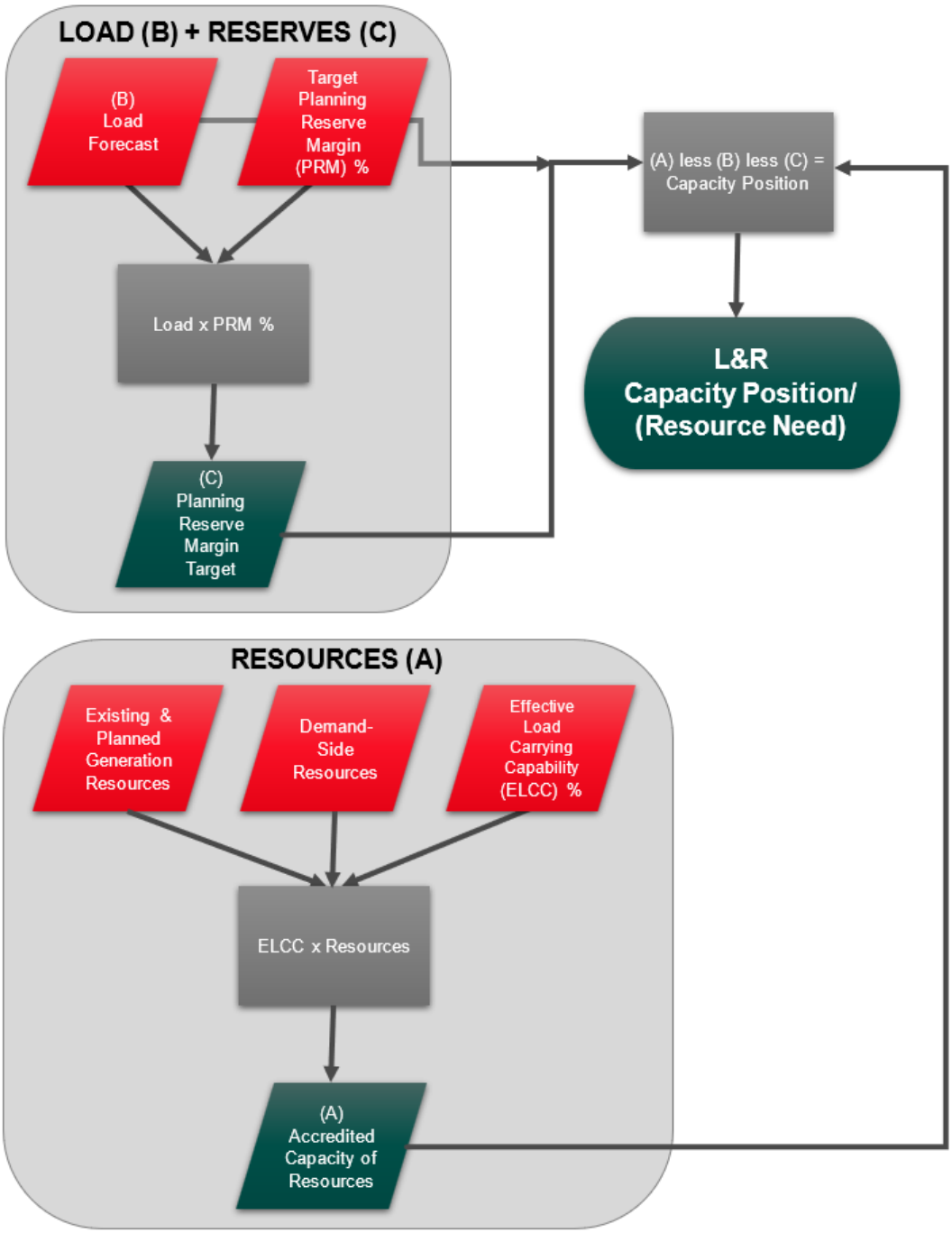
By comparing the forecast of electric demand with the existing/planned level of installed generation resources and planning reserve margins over the RAP, the Company determines whether there is a need for additional generation capacity on the system. This assessment is commonly referred to as a "load and resource balance" or "L&R." Over the course of this 2024 JTS process, the Company will provide L&R projections in both Phase I and Phase II. These Phase I and Phase II L&R projections serve different purposes and are expected to vary as described below.

- ERP Phase I L&R – developed and provided at the time the Company files its 2024 JTS. Its primary function is to provide an initial projection of capacity needs (i.e., resource need) that: (1) are used in the modeling of JTS portfolios, and (2) could be filled in the Phase II acquisition process. The Phase I L&R utilizes the Company's Spring 2024 forecast of firm electric demand to represent the "load side" of the balance and existing generation resources and planned generation resources to be acquired to represent the "resource side" of the balance (including demand-side resources). Both variations of the load forecast discussed in Section 2.2 (i.e., Base and Low) are used in Phase I to provide an indicative projection of how the resource portfolios might change with varying load profiles. The Phase I L&R is not intended to be the definitive representation of the resource needs the Company will fill in the Phase II competitive resource acquisition process.

- ERP Phase II L&R – developed before receipt of bids in the 2024 JTS Phase II acquisition process to represent the resource needs to be filled through that process. This Phase II L&R is certain to show a different level of resource need than that shown in Phase I. This is because the Phase II L&R will not only reflect an update to the Company's demand forecast but also the Commission decisions from Phase I of the 2024 JTS and other proceedings that impact the determination of resource needs. For example, these could include Phase I JTS decisions related to the Company's demand forecast methodology, ELCC levels for weather-dependent generation resources, and the Company' planning reserve margin. By updating the L&R balance at the time of the Phase II competitive acquisition process, the Company will better ensure that it acquires the appropriate amount of generation resources to reliably serve the peak demands during the RAP.

Figure 2.9-1 provides an illustrative diagram of the Company's assessment of the need for additional generation capacity. The resource need or capacity position is then a result of existing and planned generation resources and demand-side resources less the load and reserves.

Figure 2.9-1 Illustrative Diagram of Assessment of Need



2024 JTS Phase I Loads & Resources Table

Table 2.9-1 and Table 2.9-2 provide the 2024 JTS Phase I L&R projection of resource capacity need for summer and winter, respectively. The columns in each table present the capacity position in the given reliability season. Therefore, Summer 2024 refers to the capacity position relative to the gross peak occurring in the period of July through August 2024, and Winter 2025 refers to the position relative to the gross peak occurring in the period of December 2024 through February 2025. Table 2.9-3 and Table 2.9-4 provided in Appendix F show the summer and winter L&R using the Low load forecast, respectively. Table 2.9-5 and Table 2.9-6 provided in Appendix F show the annual L&Rs.

Table 2.9-1 Summer Load & Resources Table (MW)

	PSCo Summer L&R Table (MW)	2024	2025	2026	2027	2028	2029	2030	2031	
1	Owned Coal	1,462	1,462	663	661	567	412	412	-	
2	Purchased Coal	-	-	-	-	-	-	-	-	
3	**Total Coal-Fired Generation**	**1,462**	**1,462**	**663**	**661**	**567**	**412**	**412**	**-**	
4	Owned Gas Steam	230	230	695	693	462	463	463	480	
5	Owned Gas Combined Cycle	1,710	1,710	1,703	1,699	1,689	1,690	1,690	1,753	
6	Purchased Gas Combined Cycle	293	293	121	-	-	-	-	-	
7	Owned Gas Combustion Turbine	833	833	782	716	711	712	712	738	
8	Purchased Gas Combustion Turbine	676	676	673	420	213	213	213	221	
9	**Total Gas-Fired Generation**	**3,742**	**3,743**	**3,975**	**3,528**	**3,076**	**3,078**	**3,078**	**3,193**	
10	Owned Storage	224	234	195	215	205	224	230	210	
11	Purchased Storage	149	155	123	136	129	142	146	133	
12	Purchased Biomass	-	-	-	-	-	-	-	-	
13	Owned Hydro	12	12	12	12	12	12	12	12	
14	Purchased Hydro	17	16	16	5	-	-	-	-	
15	Owned Solar	0.3	0.4	0.3	0.3	0.3	0.2	0.2	0.2	
16	Purchased Solar	355	378	307	310	262	196	189	188	
17	Purchased BTM Solar	104	144	150	149	113	101	107	127	
18	Purchased Community Solar	32	52	55	62	54	59	72	92	
19	Owned Wind	186	166	180	176	233	234	220	235	
20	Purchased Wind	508	453	482	458	501	502	469	499	
21	2021 ERP/CEP Resources	-	-	457	1,500	2,105	2,118	2,115	2,059	
22	Demand Response	283	352	335	372	341	387	409	417	
23	Market Purchase	200	-	-	-	-	-	-	-	
24	**Total Renewable/Other Generation**	**2,069**	**1,962**	**2,313**	**3,395**	**3,954**	**3,973**	**3,969**	**3,971**	
25	**TOTAL ACCREDITED CAPACITY**	**7,274**	**7,167**	**6,951**	**7,585**	**7,597**	**7,463**	**7,459**	**7,163**	*A*
26	Native Load Forecast - Spring 2024 (Base)	7,256	7,426	7,139	7,450	7,835	8,540	9,228	9,828	
27	Estimated TOU Impact	(72)	(99)	(100)	(101)	(103)	(104)	(106)	(108)	
28	**FIRM OBLIGATION LOAD**	**7,185**	**7,327**	**7,039**	**7,348**	**7,732**	**8,437**	**9,123**	**9,720**	*B*
29	Target Planning Reserve Margin	451	469	442	469	492	540	586	617	
30	CORE & HCEA Backup Reserves	16	16	4	4	4	4	4	4	
31	**TOTAL PLANNING RESERVE MARGIN TARGET**	**467**	**485**	**446**	**473**	**496**	**543**	**590**	**621**	*C*
32	Actual Reserve Margin	89	(161)	(88)	236	(135)	(974)	(1,663)	(2,556)	*A-B*
33	**CAPACITY POSITION: LONG/(SHORT)**	**(378)**	**(646)**	**(534)**	**(237)**	**(631)**	**(1,517)**	**(2,253)**	**(3,177)**	*A-B-C*

Table 2.9-2 Winter Load & Resources Table (MW)

	PSCo Winter L&R Table (MW)	2024	2025	2026	2027	2028	2029	2030	2031	
1	Owned Coal	1,437	1,437	655	655	566	411	411	-	
2	Purchased Coal	-	-	-	-	-	-	-	-	
3	**Total Coal-Fired Generation**	**1,437**	**1,437**	**655**	**655**	**566**	**411**	**411**	**-**	
4	Owned Gas Steam	224	224	672	678	454	452	452	452	
5	Owned Gas Combined Cycle	1,808	1,808	1,797	1,799	1,795	1,786	1,786	1,786	
6	Purchased Gas Combined Cycle	303	303	130	-	-	-	-	-	
7	Owned Gas Combustion Turbine	907	907	849	770	768	764	764	764	
8	Purchased Gas Combustion Turbine	710	710	706	707	421	213	213	213	
9	**Total Gas-Fired Generation**	**3,953**	**3,953**	**4,154**	**3,954**	**3,439**	**3,215**	**3,216**	**3,216**	
10	Owned Storage	148	148	146	142	152	150	173	187	
11	Purchased Storage	98	98	96	87	94	93	108	117	
12	Purchased Biomass	-	-	-	-	-	-	-	-	
13	Owned Hydro	4	4	4	4	4	5	5	5	
14	Purchased Hydro	8	8	8	8	-	-	-	-	
15	Owned Solar	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	
16	Purchased Solar	0	0	27	51	28	60	39	14	
17	Purchased BTM Solar	0	0	5	11	24	38	22	-	
18	Purchased Community Solar	0	0	2	5	11	22	12	-	
19	Owned Wind	105	105	101	89	109	169	198	214	
20	Purchased Wind	286	286	270	239	233	363	420	456	
21	2021 ERP/CEP Resources	-	-	-	484	1,002	1,488	1,630	1,698	
22	Demand Response	69	77	80	79	111	123	155	182	
23	Market Purchase	-	-	-	-	-	-	-	-	
24	**Total Renewable/Other Generation**	**718**	**726**	**738**	**1,199**	**1,767**	**2,511**	**2,762**	**2,874**	
25	**TOTAL ACCREDITED CAPACITY**	**6,108**	**6,116**	**5,547**	**5,809**	**5,772**	**6,136**	**6,389**	**6,090**	*A*
26	Native Load Forecast - Spring 2024 (Base)	5,268	5,593	5,803	5,673	6,170	6,636	7,489	8,212	
27	Estimated TOU Impact	2	3	3	3	3	3	3	20	
28	**FIRM OBLIGATION LOAD**	**5,270**	**5,596**	**5,806**	**5,676**	**6,173**	**6,639**	**7,492**	**8,232**	*B*
29	Target Planning Reserve Margin	456	485	522	514	645	790	995	1,197	
30	CORE & HCEA Backup Reserves	22	22	5	5	6	7	8	9	
31	**TOTAL PLANNING RESERVE MARGIN TARGET**	**478**	**506**	**528**	**519**	**651**	**797**	**1,002**	**1,206**	*C*
32	Actual Reserve Margin	838	520	(259)	133	(401)	(503)	(1,104)	(2,143)	*A-B*
33	**CAPACITY POSITION: LONG/(SHORT)**	**360**	**13**	**(787)**	**(386)**	**(1,052)**	**(1,301)**	**(2,106)**	**(3,348)**	*A-B-C*

While the Phase I L&R is intended to be an initial projection of the generating system and expected resource needs used in generic modeling, the JTS is being filed during unique circumstances. The Company is currently executing on the Commission's 2021 ERP & CEP Phase II Decision, and while the overall portfolio capacity and resource mix remains largely the same. The CEP Delivery Plan was filed in Proceeding No. 21A-0141E on September 6, 2024, and the Company has determined it beneficial to present the L&R tables above so that they are representative of the most recent L&R inputs and assumptions the Company has as of this filing. This section will discuss the major changes between the JTS L&R tables presented above and the CEP Delivery Plan filing.

- CEP Delivery Plan Filing
  Table 2.9-1 above is mostly the same as Table 10 in Hearing Exhibit 166, Attachment JWI-5 in the 2024 CEP Delivery Plan (Proceeding No. 21A-0141E) and Table JWI-ST-7 in Hearing Exhibit 166, CEP Delivery Plan Testimony and Attachments of Jack W. Ihle and do not incorporate any of the actions proposed in the CEP Delivery Plan. However, the JTS L&Rs have the following changes:

  1. The JTS L&R tables presented above utilize the base load forecast as opposed to the low forecast, which is the main cause of the decrease in capacity position.

a. The CEP Delivery Plan filing included information about the low and base load forecast, with the base in Table 2.2-3 in Section 2.2 but does not break out the estimated impact of TOU rates. The row "Firm Obligation Load" would have been the same if both filings used the base forecast, but in this filing, the impact of TOU rates is explicitly stated in row 27 of both tables. This is in accordance with paragraph 22 of Decision No. C23-0557, which required the Company to include, as separate line items, its best estimate based on and supported by the most recent available data, of demand reductions resulting from the implementation of Schedules RE-TOU and C-TOU rates in the Company's L&R table in the JTS. Row 27 of the L&R tables is only representative of the RE-TOU rate. Further discussion about the development of this estimate and the reason to not include C-TOU rates can be found in Section 2.2.
b. JTS L&Rs with the low load forecast are included in Appendix F to Volume 2.

2. The CEP Delivery Plan's L&Rs used both the annual 2021 ERP & CEP ELCC and PRM conventions and included information about the updated seasonal ELCC and PRM methodologies discussed in Section 2.6, while the JTS L&Rs in Tables 2.9-1 and 2.9-2 only use the updated PRM/ELCC conventions.

3. In Tables 2.9-1 and 2.9-2, for a resource to be included in the generation resource mix for a specific summer or winter season, that resource must be available throughout the entire season. Meaning it must achieve COD prior to the beginning of the season and retire after the season is over. This is consistent with other Xcel Energy operating companies and other entities such as MISO. In previous years, the Company counted a resource if it was available in the month of the gross peak load. This previous convention is still present even in the CEP Delivery Plan filing, as the Company believes it best to incorporate this change in a Phase I proceeding. The impact to summer resource adequacy is minimal, as the majority of company owned resources and purchased power resources were planned to run throughout the summer season. There is a more significant impact on winter resource adequacy, as many planned retirements and contracts expirations occur on 12/31 of a given year. The winter season is December through February, so any resource retiring or expiring at the end of a calendar year would not contribute to the winter season in the L&R. From this change the JTS summer L&R has 3 MW less of accredited capacity for biomass in 2024 and 4 MW less of accredited capacity for hydro in 2027.

4. The CEP Delivery L&Rs have the 2021 ERP & CEP Resources with estimated of point of interconnection (“POI”) in-service dates (“ISD”) delays, and these are not incorporated into the JTS L&Rs due to the preliminary large generator interconnection agreements (“PLGIA”) not being completed, which means the POI dates are not final. For the purpose of the JTS, the as bid dates are assumed for purposes of modeling and the L&Rs. These delays result in 156 MW and 364 MW of less accredited capacity in 2026 and 2027 from the 2021 ERP/CEP Resources.

If the CEP Delivery Plan L&R used the updated ELCC/PRM methodology, the base load forecast, and does not include the 2021 ERP & CEP resources with the POI ISD delays, the L&Rs would match in all years except as noted above in 2024, 2026, and 2027.

2.10 PHASE I PLAN DEVELOPMENT AND MODELING DETAILS

This Section describes the process by which the Company developed a suite of indicative resource portfolios that meet the projected resource needs of the Company for the years 2025-2031 and the estimated costs of those portfolios over a 2050 planning period. Portfolios were developed using the EnCompass computer model to meet capacity expansion needs associated with meeting the Company's planning reserve margin target, reliability requirements, and other compliance requirements, including achieving 90 percent carbon emissions reduction from 2005 levels by 2033. See Appendix G for additional portfolio comparison tables and Appendix H for additional portfolio annual data tables.

JTS Portfolios

The Company modeled the five following JTS constructs, or scenarios:

- **Base scenario:** A Base plan that allows the model to select any generic resource;
- **ADER scenario:** A Base plan that adds 900 MW of Aggregate Distributed Energy Resources ("ADERs")—also known as Virtual Power Plants ("VPPs")—storage resources in 2028, which we call the "ADER" plan;
- **No New Gas scenario:** A Base plan that prohibits the model from selecting new gas resources, which we call the "No New Gas" plan. In lieu of selecting new gas resources, certain existing were extended beyond their existing retirement/expiration dates under the assumption that existing gas facilities would be leveraged to the fullest extent practicable to meet the firm dispatchable needs of the system. These facilities are: Plains End I&II PPA was extended from an early 2028 expiration through 2050. Fountain Valley 1-6 PPA was extended from an early 2032 expiration through 2050. In addition, Bid 1000 (two CTs) was included instead of Bid 0997 (one CT) from the 2021 ERP/CEP Resources, completing the three CTs approved in the 2021 CEP portfolio.
- **Advanced Technology scenario:** A Base plan that evaluates the impact of two advanced technology scenarios, including 1) a "Nuclear" plan that add 1,000 MW of AP1000 nuclear resources in 2039 and 2) a "Comprehensive Advanced Technology" plan that adds 500 MW of geothermal in both 2031 and 2033 and 1000 MW of AP1000 nuclear resources in both 2037 and 2039; and
- **Linear Reduction scenario:** A Base plan that replaces the 90% by 2033 emissions reduction cap with a linear reduction cap from 80% by 2030 to 100% by 2050, which we call the "Linear Reduction" plan.

For the Base, ADER, and No New Gas plans, the Company modeled both the Base and Low load forecasts (described in Section 2.2); both the Annual and Seasonal PRM methods (described in Section 2.6); and both the SCC and $0 per ton of CO_2 as cost of carbon assumptions. For the Nuclear and Comprehensive Advanced Technology plans, the Company modeled only the Base load forecast, only the Seasonal PRM method, and both the SCC and $0 per ton of CO_2 as cost of carbon assumptions. For the Linear

Reduction plan, the Company modeled only the Base load forecast, only the Seasonal PRM method, and both the SCC and $0 per ton of CO_2 as cost of carbon assumptions.

Table 2.10-1 below summarizes the 30 total JTS scenarios modeled. Each scenario is represented by an "X" in the two right-most columns of the table.

Table 2.10-1 JTS Phase I Portfolios

Portfolios*	Load Forecast	PRM Method**	SCC	$0 CO2
Base: *Any generic resource available for selection*	Base	Annual	X	X
	Base	Seasonal	X	X
	Low	Annual	X	X
	Low	Seasonal	X	X
ADER: *Adds 900 MW of ADER storage*	Base	Annual	X	X
	Base	Seasonal	X	X
	Low	Annual	X	X
	Low	Seasonal	X	X
No New Gas: *Cannot select generic gas resources*	Base	Annual	X	X
	Base	Seasonal	X	X
	Low	Annual	X	X
	Low	Seasonal	X	X
Advanced Technology:	Base	Seasonal	X	X
• ***Nuclear:*** *Adds 1,000 MW of AP1000 resources*				
• ***Comprehensive Advanced Technology:*** *Adds 3,000 MW of dispatchable CFE generation*	Base	Seasonal	X	X
Linear Reduction: *80% carbon-free by 2030, then linear reduction to 100% carbon-free by 2050*	Base	Seasonal	X	X

**Each set of portfolios, except for the Linear Reduction portfolios, meets 80% emission reduction target by 2030, 90% by 2033, and 100% by 2050.*
***In past ERPs, the Company used only the Annual PRM method. For the JTS, the Company modeled portfolios using both the Annual and Seasonal PRM methods, described in Section 2.6 of Volume 2. Public Service recommends the Seasonal PRM approach. The Annual PRM approach is included for illustrative and comparative purposes to the previous methodology.*

General Phase I Modeling Results Summary

All of the portfolios show relatively large additions of nameplate resources, both in the RAP and over the entire planning period. This is largely due to load growth, dispatchable resource retirements, and the declining ELCC's of renewable and storage resources given their already significant representation in the system. Additionally, the implementation of a static mass-based carbon cap compounds the issue given the absence of clean baseload/dispatchable generation technologies currently available for rapid implementation.

While all 30 of JTS portfolios economically selected long-duration energy storage ("LDES") resources, 22 economically selected hydrogen electrolyzer resources, and one economically selected ADER resources, none of the portfolios economically selected biomass, geothermal, AP1000, or SMR resources. This is largely dependent of the price forecasts for the various technologies, and given the development immaturity of these technologies, the price forecasts are correspondingly imprecise.

Company Witness Mr. Tomljanovic discusses in his Direct Testimony the various levels of technology maturity and readiness among advanced technologies, as well as some of

the important considerations the Company and stakeholders must evaluate as the maturity of various advanced technologies progresses.

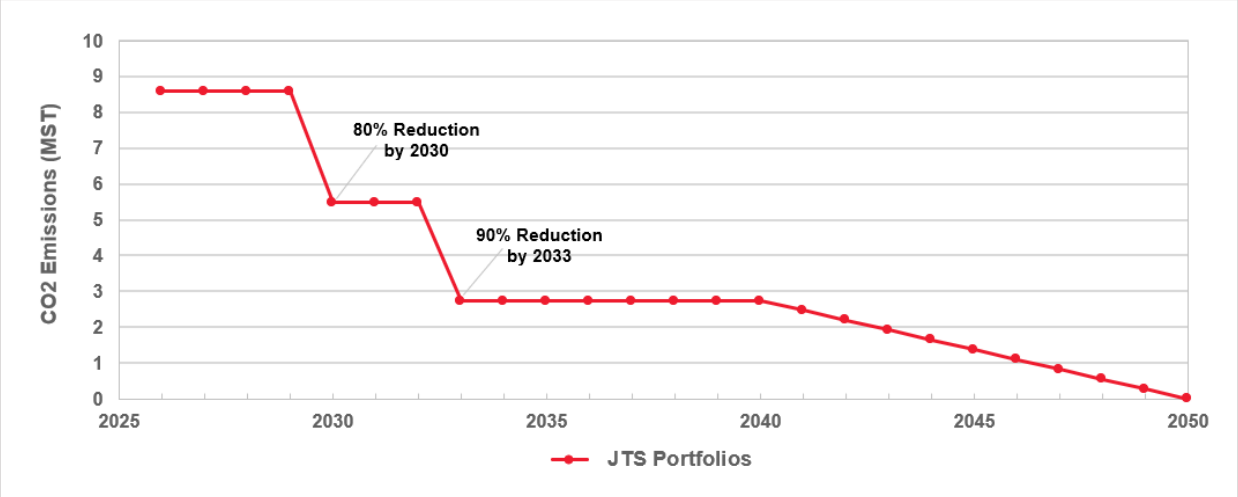
Modeling Input Assumptions

The base model was developed and populated with all the assumptions needed to represent the existing Public Service system and extend forecasts of required variables (i.e., load, fuel prices, etc.) through the planning period. For Phase I, costs and performance characteristics of generic resources were added. For Phase II, the actual individual bid costs and other bid characteristics, including just transition benefits to Pueblo and Routt counties, will be utilized. A full description of the modeling inputs and assumptions is included in Section 2.11.

Carbon Dioxide Emission Caps

The JTS portfolios were required modeled to meet annual CO_2 emission caps on a trajectory of 80% CO_2 reduction by 2030, 90% reduction by 2033, and 100% reduction by 2050, as shown in Figure 2.10-1, with the exception of the Linear Reduction portfolios described above.

Figure 2.10-1 JTS CO2 Emission Caps



EnCompass Phase 1 Modeling Steps: Portfolios were developed within the EnCompass model using a multi-step process.

Step 1 – Capacity Expansion Plan Development

In the first step of the modeling process, we developed capacity expansion portfolios that meet reliability standards and CO_2 emission caps using one typical on and off-peak day per month for the entire 2028-2050 planning period. For these runs, the EnCompass

"partial commitment" setting was used to balance model runtime while still providing accurate capacity expansion plan results.

Due to the variety of new advanced technology generic resources available to EnCompass for the JTS that weren't available in the 2021 ERP & CEP, as well as to reduce the chances of reliability shortfalls in the capacity expansion step that have to be remedied in a follow on process, the Company has evolved its Step 1 capacity expansion modeling process into two stages to ensure that appropriate levels of carbon-free resources are added to meet emissions goals and to ensure that capacity and energy adequacy are met when the portfolio is modeled in a full 8760 dispatch.

In the first part of step one, Step 1A, the capacity expansion run, the full planning period is modeled in a single simulation using a typical on and off-peak day per month and eleven time intervals per day. This aggregation of time intervals has been recommended by the EnCompass software vendor for long term simulations. From this expansion plan run, the size and timing of wind and solar resources added is extracted and are locked into the model proceeding into the second step, Step 1B, of the simulation.

In Step 1B, the model developed capacity expansion portfolios using all calendar days of the planning period, as opposed to only two days per month in Step 1A. Step 1B maintains the 11 time intervals per day, however, rather than modeling 24 hours for every day of the year. With this increased dispatch granularity in the optimization, the problem size increased significantly. To allow the model to solve within a reasonable amount of time, the optimization horizon in Step 1B is reduced to every two years. In Step 1B, the model also uses the wind and solar selections from Step 1A as a floor for the minimum wind and solar capacity needs in Step 1B. Step 1B allows EnCompass to capture most of the hourly granularity when evaluating resource options while balancing problem size and run time.

Step 2 – 8760-Dispatch

The second step involved performing 8760-hourly dispatch ("8760-dispatch") for each year of each optimized portfolio from 2025-2050. The planning period for this modeling step differs from the previous capacity expansion steps due to the need in this step to dispatch the years prior to the RAP. These 8760-dispatch runs were used to determine the production costs and dispatch metrics of each portfolio, and the results of these 8760-dispatch runs are used to produce all data shown in this filing relating to the model output (i.e., portfolio costs, CO_2 emissions, energy mix, etc.).

Step 2 runs were completed using a full chronological 8760 hour-per-year dispatch and included all ancillary service requirements and economic commitment and dispatch of all resources, including storage charge and discharge. For these runs, the Company used the "partial commitment" setting to again balance model runtime while still providing accurate annualized production cost information.

For the Step 2 8760-dispatch, the Company used $0 per ton of CO_2 as the cost of carbon. Absent any future regulatory action, the Company generally considers the 8760-dispatch

without the SCC in the dispatch decision as more reflective of current expectations and more realistic in modeling the real-life system dispatch decisions faced by system operators.

Application of CO_2 Costs: As illustrated in Table 2.10-1 above, all JTS portfolios were optimized using both the SCC and $0 per ton of CO_2 cost of carbon assumptions. The annual $/ton rate used to represent the SCC is discussed in Section 2.11.

Discounting of Fuel Costs for NPV
All NPV calculations use the inflation rate for discounting carbon-based fuel costs, and WACC for everything else, in accordance with Colorado SB 23-291.

Fuel Supply: All JTS portfolios were modeled in Phase I with firm fuel supply and incremental gas storage needs consistent with the previous ERP.

Transmission: The expansion plans were optimized using incremental generic transmission cost "adders" for each generic resource as discussed in Section 2.11.

Results: Base, Nuclear, and Comprehensive Advanced Technology Plans

Presented in Table 2.10-2 and Figure 2.10-2 are the detailed results for six of the 30 total JTS portfolio optimizations. Two of the six are Base portfolios, two are Nuclear portfolios, and two are Comprehensive Advanced Technology portfolios.

All six portfolios shown below were optimized in Step 1 using the Base load forecast and the Seasonal PRM method. Regarding cost of carbon assumptions in Step 1, one each of the Base, Nuclear, and Comprehensive Advanced Technology portfolios shown below were optimized using the SCC and the other Base, Nuclear, and Comprehensive Advanced Technology portfolios shown below used $0 per ton of CO_2.

The Present Value of Revenue Requirements ("PVRR") and EnCompass System Cost Rate 2031 values reported in Table 2.10-2 for each portfolio were developed from the 8760-dispatch of each portfolio over the 2025-2050 planning period.

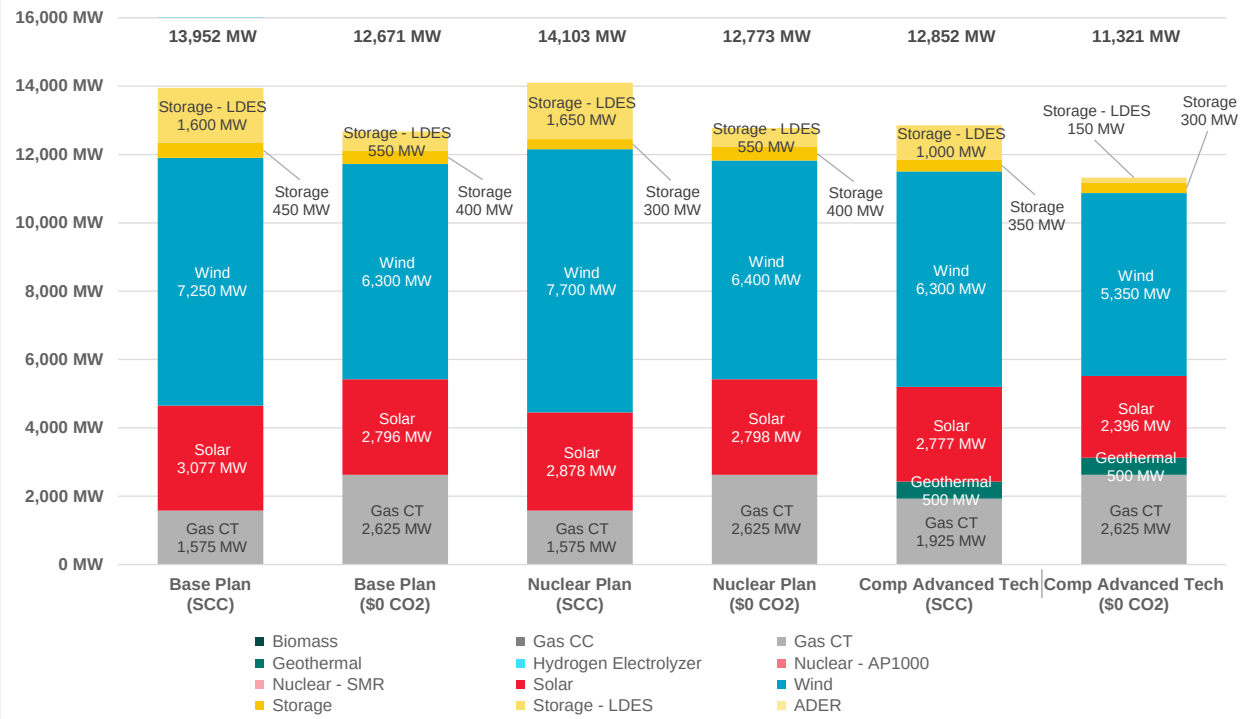
Table 2.10-2 Base, Nuclear, and Comprehensive Advanced Technology Plan Detailed Results

PSCo 2024 JTS Portfolios' Comparison

Resource Additions 2025-2031 (MW)	Base Plan (SCC)	Base Plan ($0 CO2)	Nuclear Plan (SCC)	Nuclear Plan ($0 CO2)	Comp Advanced Tech (SCC)	Comp Advanced Tech ($0 CO2)
Biomass						
Gas CC						
Gas CT	1,575	2,625	1,575	2,625	1,925	2,625
Geothermal					500	500
Hydrogen Electrolyzer						
Nuclear - AP1000						
Nuclear - SMR						
Solar	3,077	2,796	2,878	2,798	2,777	2,396
Wind	7,250	6,300	7,700	6,400	6,300	5,350
Storage	450	400	300	400	350	300
Storage - LDES	1,600	550	1,650	550	1,000	150
ADER						
TOTAL Nameplate Capacity Additions (MW)	**13,952**	**12,671**	**14,103**	**12,773**	**12,852**	**11,321**
Dispatchable	1,575	2,625	1,575	2,625	2,425	3,125
Renewable	10,327	9,096	10,578	9,198	9,077	7,746
Storage	2,050	950	1,950	950	1,350	450
TOTAL Accredited Capacity (MW)	**4,432**	**4,307**	**4,381**	**4,314**	**4,504**	**4,227**
Present Value Revenue Requirement (PVRR)						
PVRR RAP 2025-2031 ($M)	$ 14,859	$ 15,238	$ 14,883	$ 15,246	$ 14,134	$ 14,348
PVRR 2025-2040 ($M)	$ 38,598	$ 38,289	$ 37,610	$ 37,655	$ 40,428	$ 40,322
PVRR Planning Period 2025-2050 ($M)	**$ 64,437**	**$ 63,939**	**$ 65,104**	**$ 64,482**	**$ 72,079**	**$ 71,446**
PVRR Delta vs. Base Plan ($M)	$ -	$ (498)	$ 667	$ 45	$ 7,642	$ 7,009
Emissions						
CO2 2025-2031 (M Tons)	46,724,934	53,057,713	46,854,608	52,882,726	46,778,089	53,013,101
CO2 2025-2050 (M Tons)	73,945,580	81,751,436	74,655,613	80,980,174	72,415,007	79,645,799
CO2 Delta vs. Base Plan 2025-2050 (M Tons)	-	7,805,857	710,033	7,034,594	(1,530,572)	5,700,219
CO2 Reduction 2031 from 2005 (%)	-92.0%	-87.1%	-92.3%	-87.2%	-91.8%	-87.1%
NPV CO2 at SCC 2025-2050 ($M)	$ 5,520	$ 6,115	$ 5,563	$ 6,064	$ 5,426	$ 5,985
NPV Methane at SCM 2025-2050 ($M)	$ 83	$ 97	$ 83	$ 95	$ 80	$ 94
TOTAL Present Value Societal Cost (PVSC) ($M)	**$ 70,039**	**$ 70,151**	**$ 70,750**	**$ 70,641**	**$ 77,584**	**$ 77,524**
PVSC Delta vs. Base Plan ($M)	$ -	$ 112	$ 711	$ 602	$ 7,545	$ 7,485
Miscellaneous						
Natural Gas Burn 2025-2031 (GBtu)	362,404	463,689	363,847	460,305	363,600	463,261
Renewable Energy 2031 (%)	92.9%	88.4%	93.2%	88.5%	92.6%	88.4%
Avg. EnCompass System Cost Rate RAP ($/MWh)	$ 57.86	$ 59.14	$ 57.95	$ 59.18	$ 55.14	$ 55.81
Avg. EnCompass System Cost Rate Planning Period ($/MWh)	$ 83.05	$ 82.37	$ 84.52	$ 83.54	$ 94.67	$ 93.72

Notes: All portfolios in this table utilize the base load forecast, and seasonal PRMs and ELCCs. All capacity values are coincident with the July peak.

Figure 2.10-2 Base, Nuclear, and Comprehensive Advanced Technology Plan Capacity Expansion Results – RAP



Results Discussion: Base Plan (SCC) vs. Base Plan ($0 CO_2)

As indicated in Table 2.10-2, the Base portfolio optimized using the SCC achieves 92% CO_2 reduction in 2031 from 2005 levels, while the Base portfolio optimized using $0 per ton of CO_2 achieves a lower 87.1% CO_2 reduction. The Base portfolio with the SCC adds 1,050 MW fewer dispatchable resources, 1,231 MW more renewable resources, and 1,100 MW more storage resources. Regarding the cost differences, the Base portfolio with the SCC's PVRR is $379M lower than the Base portfolio with $0 per ton of CO_2 during the RAP but $498M higher through the end of the planning period. Regarding advanced technologies, the Base portfolio with the SCC selected 1,600 MW of long duration energy storage during the RAP and the Base portfolio with $0 per ton of CO_2 selected 550 MW of long duration energy storage during the RAP. Both portfolios added between approximately 6,250-6,350 MW of long duration energy storage and between 18-28 MW of hydrogen electrolyzers through the end of the planning period.

Results Discussion: Nuclear and Comprehensive Advanced Technology Plans

The Company developed the Nuclear and Comprehensive Advanced Technology portfolios to support the ongoing conversation with stakeholders about the variety of generation technologies that may contribute to a carbon-free electricity system by 2050. The results below don't indicate any specific proposal, recommendation, or decision by the Company related to advanced technologies, but are intended to show the role such technologies could play in a decarbonized electric system. Furthermore, the cost

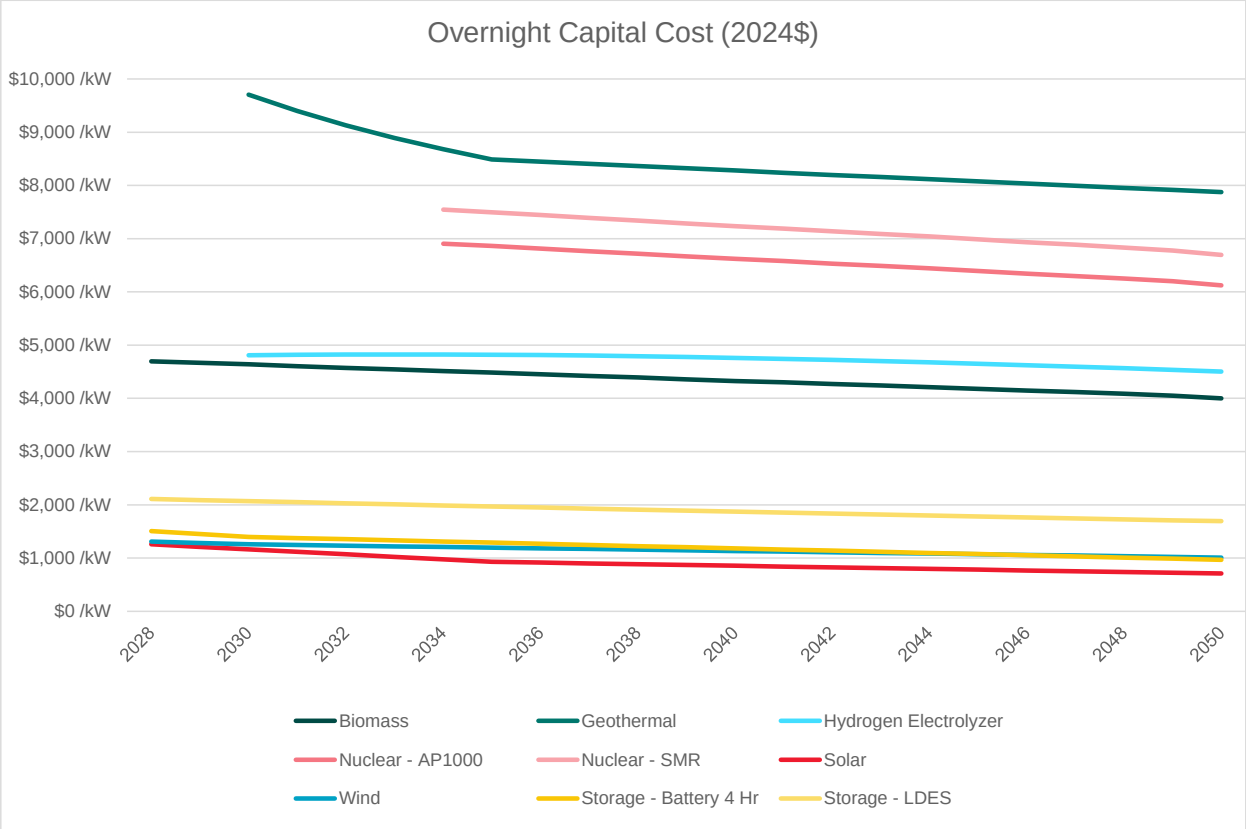
assumptions for the generic advanced technologies modeled are highly speculative, as discussed below, so although the costs of the advanced technology scenarios model as higher than those without them, those cost values are largely irrelevant at this juncture.

As indicated in Table 2.10-2 above, in the RAP the Nuclear portfolio with the SCC achieves a 92.3% CO_2 reduction in 2031, which is slightly higher than the Base portfolio with the SCC (92%). As the Nuclear-only scenario does not add the nuclear resource until 2039, there are not expected to be many differences when only looking at the RAP. The Comprehensive Advanced Technology portfolio with the SCC achieves a 91.8% CO_2 reduction in 2031, which is essentially the same as the Base portfolio.

The Nuclear portfolio with the SCC adds the same amount of dispatchable resources, 100 MW fewer storage resources, and approximately 250 MW more renewable resources than the Base portfolio with the SCC during the RAP. The Comprehensive Advanced Technology portfolio with the SCC adds 850 MW more dispatchable resources (500 MW of which are carbon-free geothermal resources), 700 MW fewer storage resources, and 1,250 MW fewer renewable resources than the Base portfolio with the SCC during the RAP.

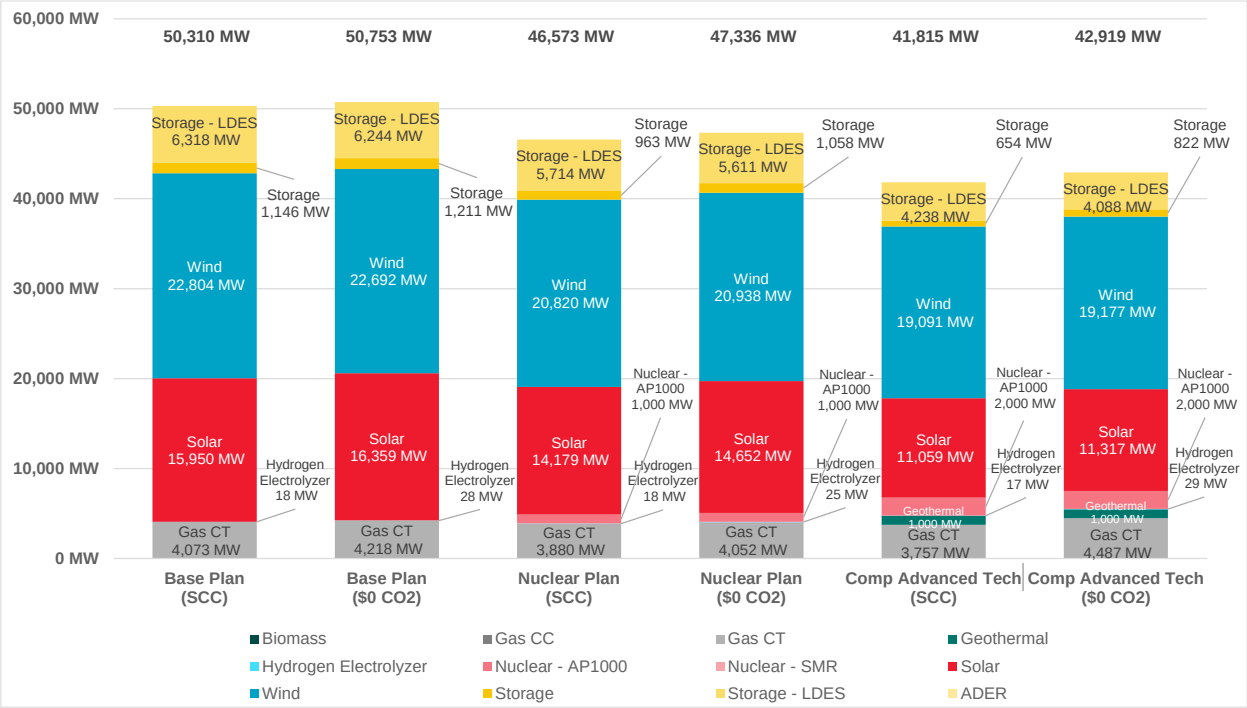
The Nuclear portfolio with the SCC's PVRR is approximately $24M higher than the Base portfolio with the SCC during the RAP, and it is $667M higher through the end of the planning period. The Comprehensive Advanced Technology portfolio with the SCC's PVRR is approximately $725M lower than the Base portfolio with the SCC during the RAP, and it is $7,642M higher through the end of the planning period. As stated above, these costs are highly speculative. Figure 2.10-3 below details the generic cost forecasts, in real dollars, and are primarily derived from the 2023 NREL ATB. As can be seen, the advanced technology costs are high, and show relatively little reduction in cost going forward, unlike normal expectations as a technology matures and is commercialized. Although wind, solar, and storage are also relatively flat, those technologies are more mature, and if costs looking back 10-15 years were included, they would show a large reduction in cost as the technology matured. The Company reviews the cost assumptions for all generic resources in Section 2.11.

Figure 2.10-3 Generic Resource Overnight Capital Cost Forecasts



The major differences among the Base, Nuclear, and Comprehensive Advanced Technology portfolios appear in the years after the RAP. This is because the earliest that either of the Nuclear and Comprehensive Advanced Technology portfolios adds a generic advanced technology resource is in 2031 – the final year of the RAP. There are notable differences in total capacity expansion by 2050 among the Base, Nuclear, and Comprehensive Advanced Technology portfolios, as detailed in Figure 2.10-4.

Figure 2.10-4 Base, Nuclear, and Comprehensive Advanced Technology 2050 Portfolio Size and Resource Composition



The Nuclear portfolio avoids 3,736 MW of capacity through 2050 as compared to the Base portfolio by adding a single 1,000 MW of nuclear resources in 2039. Thus, the advanced technology avoids 3.7x MW nameplate other resources. Stated another way, 1x MW of advanced technology is equivalent to 4.7x MW of current resource technology.

The Comprehensive Advanced Technology portfolio avoids 8,495 MW of capacity through 2050 as compared to the Base portfolio by adding a 500 MW geothermal resource in 2031 and 2033 and a 1,000 MW nuclear resource in 2037 and 2039. Thus, for the broader advanced technology scenario, the advanced technology avoids 2.8x MW's and a 1x MW addition is equivalent to 3.8x MW of current resource types. Table 2.10-3 compares the difference in 2050 portfolio size among a broader set of JTS portfolios to the Base portfolio with the SCC.

Table 2.10-3 Difference in 2050 Portfolio Size, as Compared to the Base Portfolio

Portfolio	2050 Nameplate Capacity Additions (MW)	Delta vs. Base (MW)
Base Plan (SCC)	50,310	-
ADER Plan (SCC)	50,435	125
No New Gas Plan (SCC)	54,617	4,307
Nuclear Plan (SCC)	46,573	(3,736)
Comp Advanced Tech (SCC)	41,815	(8,495)

Notes: All portfolios in this table utilize the base load forecast, and seasonal PRMs and ELCCs. All capacity values are coincident with the July peak.

The Nuclear and Comprehensive Advanced Technology portfolios result in markedly lower 2050 portfolio nameplate capacity because they integrate dispatchable carbon-free electricity ("CFE") generation resources. Dispatchable CFE generation resources, like geothermal and nuclear, have the effect of reducing portfolio nameplate capacity because they contribute higher marginal accredited capacity values per incremental megawatt than renewable and storage resources do. Put another way, one megawatt of dispatchable CFE generation resources adds a capacity value to the system that requires a combination of multiple megawatts of renewable and storage resources to match.

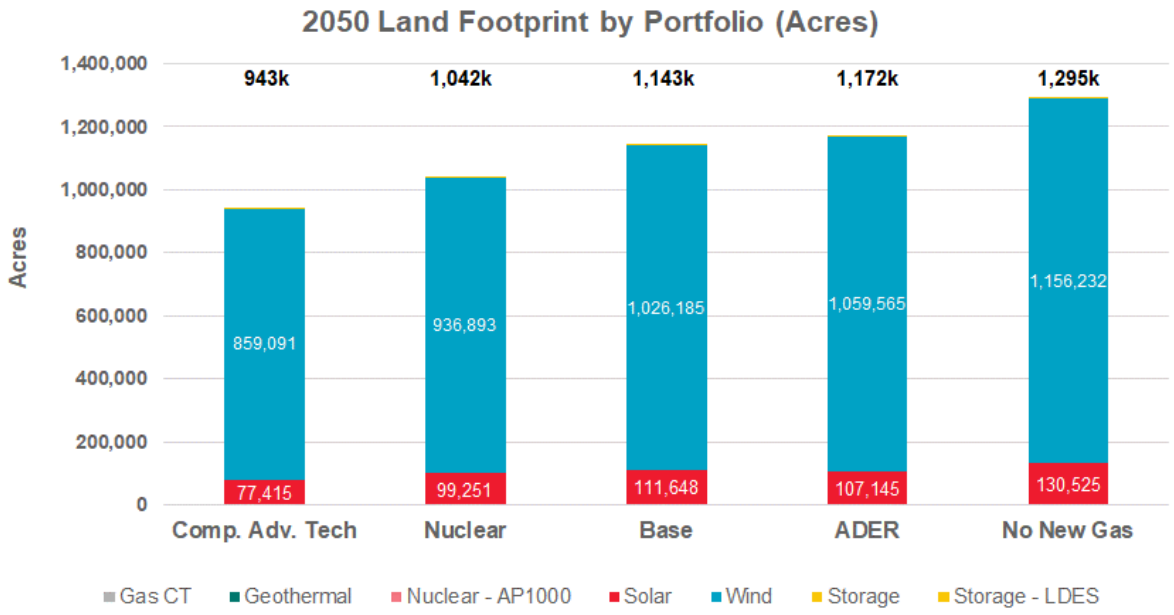
Portfolios with more dispatchable CFE generation resources achieve lower ratios of nameplate to accredited capacity. The Comprehensive Advanced Technology portfolio with the SCC's 2050 nameplate to accredited capacity ratio is 3.2:1, while the No New Gas portfolio's 2050 nameplate to accredited capacity ratio is 4.4:1.

Generally, portfolios with lower nameplate capacity values require less land and fewer new transmission lines. To estimate the land footprint of various JTS portfolios, the Company multiplied the nameplate capacity of the resources within a portfolio by the resource type's power density - a measure of the land required per MW nameplate. Table 2.10-4 shows the power density assumptions the Company used to calculate portfolio land footprint. These assumptions were gathered from various literature reviews and internal experts and are intended to be representative of a range of possible values depending on the specifics of each project and project site. Figure 2.10-5 shows estimated 2050 land footprints using these values for the various JTS portfolios.

Table 2.10-4 Power Density by Resource Type (acres/MW nameplate)

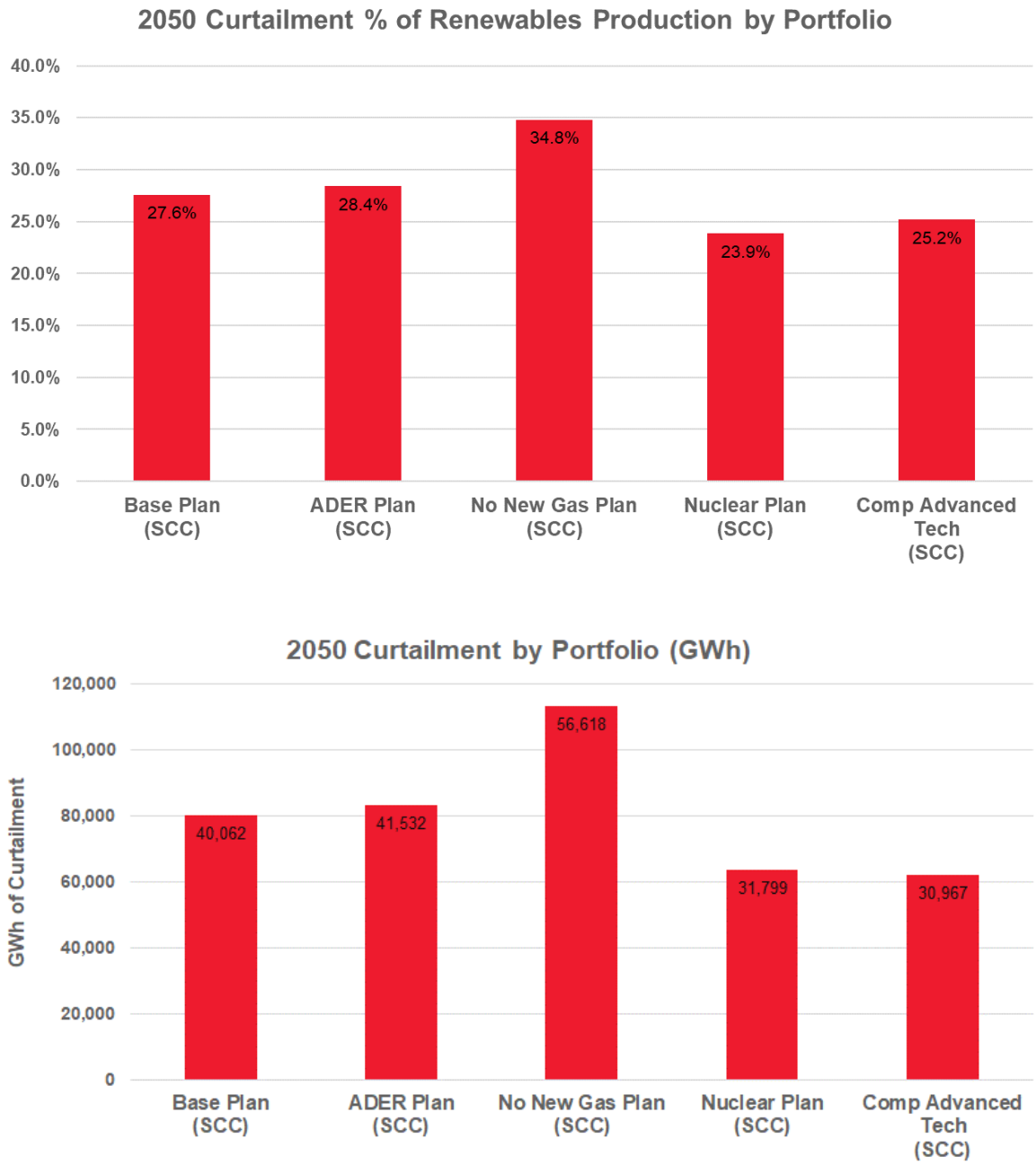
Power Density by Resource Type (acres/MW nameplate)	
ADER	0.0
Gas CC	0.1
Gas CT	0.1
Storage	0.1
Storage - LDES	0.8
Nuclear	0.9
Geothermal	1.2
Solar	7.0
Wind	45.0
Biomass	1977.2

Figure 2.10-5 2050 Land Footprint by Portfolio (Acres)



In addition to the nameplate capacity and corresponding land use implications supporting dispatchable CFE generation technologies, the reduction in weather-dependent (wind and solar) generation results in less curtailed renewable energy. This occurs even when the economically optimum level of storage is included to match the renewable generation and curtailments in each portfolio. Simply put, it is not economical to add enough storage to capture all curtailments, and the Encompass model will “right size” storage to the correct economic breakeven point. The impact of dispatchable CFE generation resources on curtailment levels is shown below in Figure 2.10-6.

Figure 2.10-6 2050 Curtailments



As the system becomes more saturated with renewable and storage resources, each additional megawatt of renewable and storage resources built in pursuit of a carbon-free system contributes a declining capacity value (ELCC) to system reliability. Consequently, in a scenario focused primarily on renewable and storage resources in pursuit of a carbon-free system, the Company will "chase" its system reliability target by adding *ever increasing* amounts of resources that individually contribute *constantly declining* incremental capacity value. Portfolio nameplate capacity and total land need in this

scenario balloon to achieve the system's needed level of accredited capacity to maintain reliability.

Portfolios with high-capacity-factor dispatchable CFE generation resources avoid this "chasing problem" entirely. This is because adding increasing amounts of dispatchable resources contributes *stable*, rather than declining, capacity value to the system. The cause for this difference is that the ELCC for dispatchable resources is essentially flat regardless of the amount added, as it is primarily a function of forced outage rate and does not experience the antagonistic ELCC effects seen in weather-dependent resources and shorter duration storage.

LDES also has relatively flat ELCC curves but is not as effective of a system dispatch tool. LDES also has long duration charge times, and at current efficiencies, a 100 hour iron-air battery takes over 200 hours to charge. This requires operators to have foresight measured in weeks on when to charge and discharge the storage, which renders it challenging to utilize to meet emergent system needs such as unexpected, forced outages or severe weather events, in addition to daily system balancing.

However, dispatchable CFE generation resources and LDES are still in early development, making gas resources the only dispatchable resources available now with high accredited capacity values. While new gas resources are not an ideal solution in terms of progressing to a zero carbon system, they are necessary to maintain current system reliability, and are run at low capacity factors to meet system emission reduction goals. Dispatchable CFE generation resources, when they become widely available, will be unconstrained by emissions and can operate at high capacity factors and displace the need for weather-dependent and storage resources.

The Company and stakeholders together will have to consider portfolio impacts beyond cost and emissions in light of this looming challenge: To build a practically-sized, operationally-efficient, and realistically deliverable portfolio as the system approaches 100% carbon-free. Land footprint; new transmission needs; resource curtailment levels; water consumption; wildlife impacts; and more will have to come into a collaborative discussion about which portfolio is "best" for Colorado's future.

Results: Linear Reduction Plan

Presented in Table 2.10-5 and Figure 2.10-7 are the detailed results for the two Linear Reduction Plan portfolios of the 30 total JTS portfolio optimizations.

Both Linear Reduction portfolios were optimized in Step 1 using the Base load forecast and the Seasonal PRM method. Regarding cost of carbon assumptions in Step 1, one Linear Reduction portfolio was optimized using the SCC and the other using $0 per ton of CO_2.

The Present Value of Revenue Requirements ("PVRR") and EnCompass System Cost Rate 2031 values reported in Table 2.10-5 for each portfolio were developed from the 8760-dispatch of each portfolio over the 2025-2050 planning period.

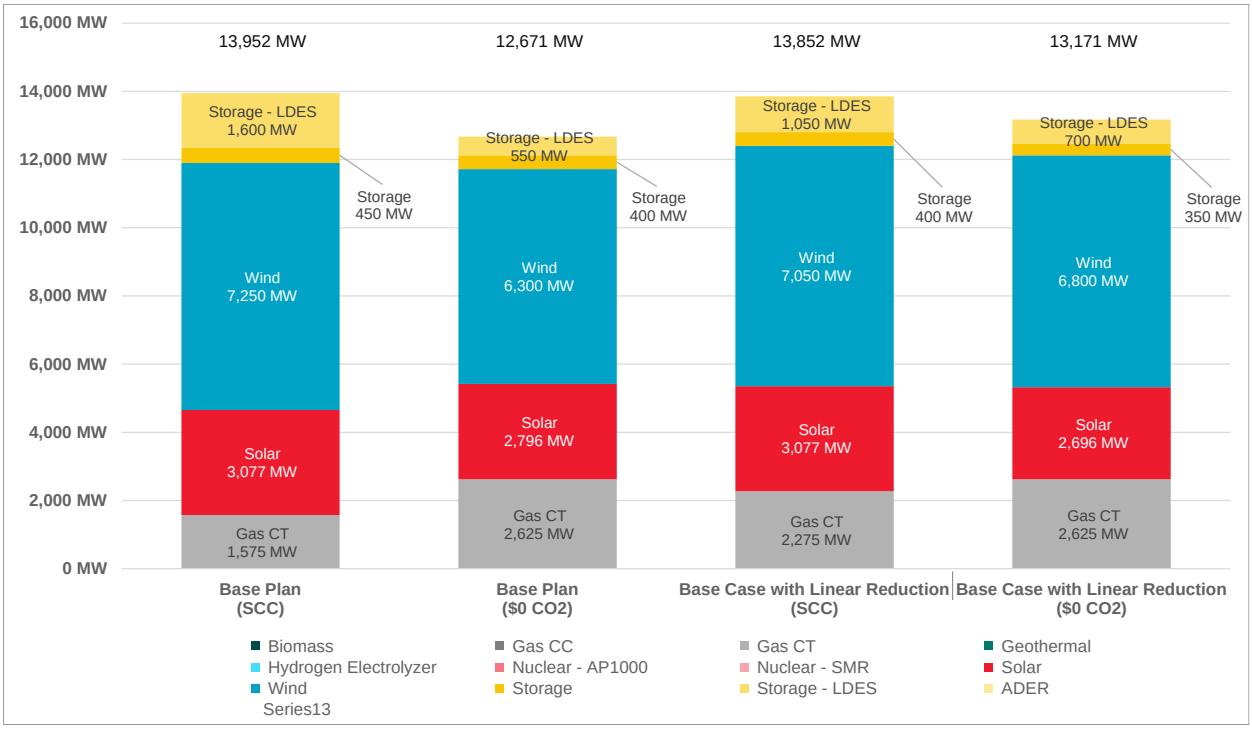
Table 2.10-5 Linear Reduction Plan Detailed Results

PSCo 2024 JTS Portfolios' Comparison

Resource Additions 2025-2031 (MW)	Base Plan (SCC)	Base Plan ($0 CO2)	Base Case with Linear Reduction (SCC)	Base Case with Linear Reduction ($0 CO2)
Biomass				
Gas CC				
Gas CT	1,575	2,625	2,275	2,625
Geothermal				
Hydrogen Electrolyzer				
Nuclear - AP1000				
Nuclear - SMR				
Solar	3,077	2,796	3,077	2,696
Wind	7,250	6,300	7,050	6,800
Storage	450	400	400	350
Storage - LDES	1,600	550	1,050	700
ADER				
TOTAL Nameplate Capacity Additions (MW)	**13,952**	**12,671**	**13,852**	**13,171**
Dispatchable	1,575	2,625	2,275	2,625
Renewable	10,327	9,096	10,127	9,496
Storage	2,050	950	1,450	1,050
TOTAL Accredited Capacity (MW)	**4,432**	**4,307**	**4,522**	**4,438**
Present Value Revenue Requirement (PVRR)				
PVRR RAP 2025-2031 ($M)	$ 14,859	$ 15,238	$ 15,254	$ 15,194
PVRR 2025-2040 ($M)	$ 38,598	$ 38,289	$ 38,668	$ 38,201
PVRR Planning Period 2025-2050 ($M)	**$ 64,437**	**$ 63,939**	**$ 64,437**	**$ 64,046**
PVRR Delta vs. Base Plan ($M)	$ -	$ (498)	$ 1	$ (390)
Emissions				
CO2 2025-2031 (M Tons)	46,724,934	53,057,713	47,162,980	52,532,890
CO2 2025-2050 (M Tons)	73,945,580	81,751,436	79,228,918	85,326,751
CO2 Delta vs. Base Plan 2025-2050 (M Tons)	-	7,805,857	5,283,339	11,381,172
CO2 Reduction 2031 from 2005 (%)	-92.0%	-87.1%	-90.4%	-88.5%
NPV CO2 at SCC 2025-2050 ($M)	$ 5,520	$ 6,115	$ 5,883	$ 6,351
NPV Methane at SCM 2025-2050 ($M)	$ 83	$ 97	$ 92	$ 103
TOTAL Present Value Societal Cost (PVSC) ($M)	**$ 70,039**	**$ 70,151**	**$ 70,412**	**$ 70,500**
PVSC Delta vs. Base Plan ($M)	$ -	$ 112	$ 373	$ 461
Miscellaneous				
Natural Gas Burn 2025-2031 (GBtu)	362,404	463,689	370,256	455,190
Renewable Energy 2031 (%)	92.9%	88.4%	91.4%	89.7%
Avg. EnCompass System Cost Rate RAP ($/MWh)	$ 57.86	$ 59.14	$ 59.31	$ 59.00
Avg. EnCompass System Cost Rate Planning Period ($/MWh)	$ 83.05	$ 82.37	$ 82.93	$ 82.53

Notes: All portfolios in this table utilize the base load forecast, and seasonal PRMs and ELCCs. All capacity values are coincident w/ the July peak.

Figure 2.10-7 Linear Reduction Plan Capacity Expansion Graph - RAP



Results Discussion: Linear Reduction Plan vs. Base Plan

As indicated in Table 2.10-5, the Linear Reduction portfolio optimized using the SCC achieves 90.4% CO_2 reduction in 2031 from 2005 levels. This reduction is slightly lower than the Base portfolio with the SCC (92%) and slightly higher than the Linear Reduction portfolio optimized using $0 per ton of CO_2, which achieves an 88.5% reduction.

The Linear Reduction portfolio with the SCC adds 700 MW more dispatchable resources, 200 MW fewer renewable resources, and 600 MW fewer storage resources than the Base portfolio with the SCC. Using $0 per ton of CO_2, the Linear Reduction portfolio adds the same amount of dispatchable resources, 400 MW more renewable resources, and 100 MW more storage resources than the Base portfolio.

The Linear Reduction portfolio with the SCC's PVRR is approximately $396M higher during the RAP and $1M higher through the planning period than the Base portfolio with the SCC. Using $0 per ton of CO_2, the Linear Reduction portfolio is $44M lower in the RAP and $107M higher over the planning period.

The Linear Reduction portfolios selected between 700-1,050 MW of long duration energy storage during the RAP. Both Linear Reduction portfolios added approximately 6,300 MW of long duration energy storage and between 18-28 MW of hydrogen electrolyzers through the end of the planning period. The Linear Reduction portfolio with $0 per ton of CO_2 was the only of all 30 JTS portfolios to economically select ADER resources, of which it selected 50 MW through the end of the planning period.

Results: ADER Plan

Presented in Table 2.10-6 and Figure 2.10-8 are the detailed results for two ADER Plan portfolios of the 30 total JTS portfolio optimizations.

Each of the ADER portfolios shown below was optimized in Step 1 using the Base load forecast and the Seasonal PRM method. Regarding cost of carbon assumptions in Step 1, one of the ADER portfolios shown below was optimized using the SCC and the other using $0 per ton of CO_2.

The Present Value of Revenue Requirements ("PVRR") and EnCompass System Cost Rate 2031 values reported in Table 2.10-6 for each portfolio were developed from the 8760-dispatch of each portfolio over the 2025-2050 planning period.

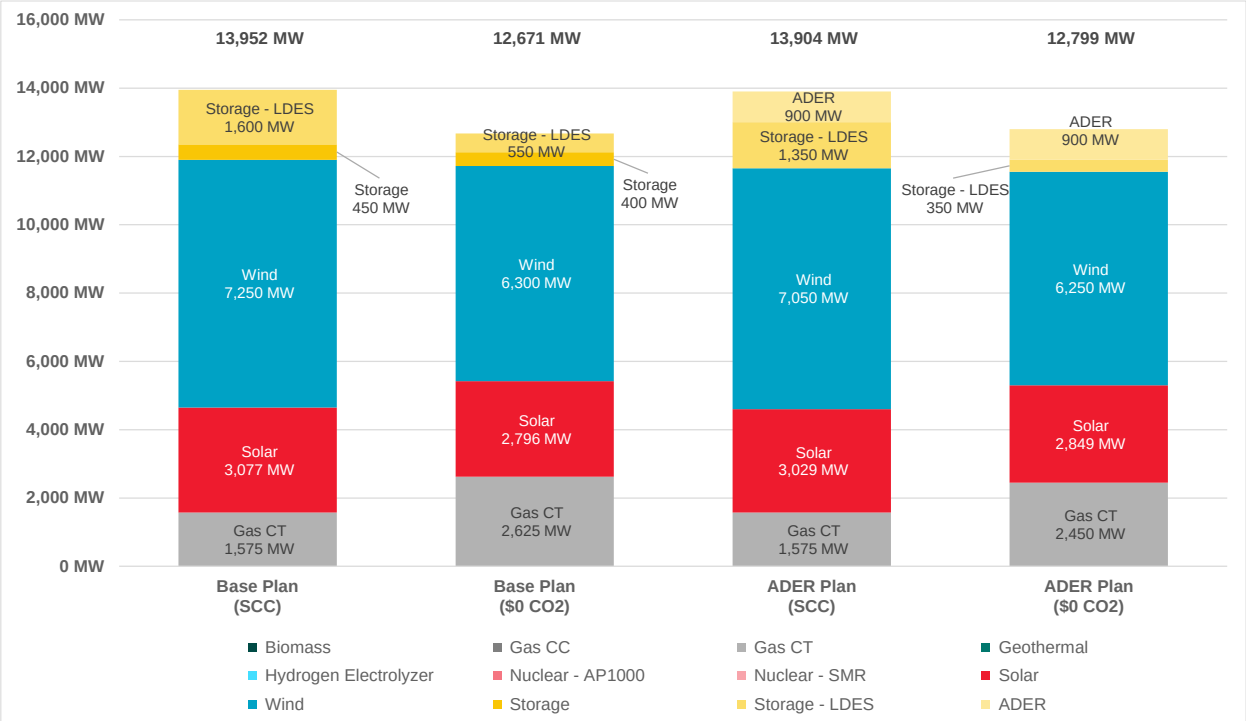
Table 2.10-6 ADER Plan Detailed Results

PSCo 2024 JTS Portfolios' Comparison

Resource Additions 2025-2031 (MW)	Base Plan (SCC)	Base Plan ($0 CO2)	ADER Plan (SCC)	ADER Plan ($0 CO2)
Biomass				
Gas CC				
Gas CT	1,575	2,625	1,575	2,450
Geothermal				
Hydrogen Electrolyzer				
Nuclear - AP1000				
Nuclear - SMR				
Solar	3,077	2,796	3,029	2,849
Wind	7,250	6,300	7,050	6,250
Storage	450	400		
Storage - LDES	1,600	550	1,350	350
ADER			900	900
TOTAL Nameplate Capacity Additions (MW)	**13,952**	**12,671**	**13,904**	**12,799**
Dispatchable	1,575	2,625	1,575	2,450
Renewable	10,327	9,096	10,079	9,099
Storage	2,050	950	2,250	1,250
TOTAL Accredited Capacity (MW)	**4,432**	**4,307**	**4,489**	**4,301**
Present Value Revenue Requirement (PVRR)				
PVRR RAP 2025-2031 ($M)	$ 14,859	$ 15,238	$ 15,301	$ 15,629
PVRR 2025-2040 ($M)	$ 38,598	$ 38,289	$ 39,876	$ 39,867
PVRR Planning Period 2025-2050 ($M)	**$ 64,437**	**$ 63,939**	**$ 66,528**	**$ 66,120**
PVRR Delta vs. Base Plan ($M)	$ -	$ (498)	$ 2,091	$ 1,684
Emissions				
CO2 2025-2031 (M Tons)	46,724,934	53,057,713	46,416,180	51,818,540
CO2 2025-2050 (M Tons)	73,945,580	81,751,436	74,252,328	80,585,578
CO2 Delta vs. Base Plan 2025-2050 (M Tons)	-	7,805,857	306,748	6,639,998
CO2 Reduction 2031 from 2005 (%)	-92.0%	-87.1%	-91.6%	-87.1%
NPV CO2 at SCC 2025-2050 ($M)	$ 5,520	$ 6,115	$ 5,535	$ 6,023
NPV Methane at SCM 2025-2050 ($M)	$ 83	$ 97	$ 83	$ 95
TOTAL Present Value Societal Cost (PVSC) ($M)	**$ 70,039**	**$ 70,151**	**$ 72,146**	**$ 72,238**
PVSC Delta vs. Base Plan ($M)	$ -	$ 112	$ 2,107	$ 2,199
Miscellaneous				
Natural Gas Burn 2025-2031 (GBtu)	362,404	463,689	357,169	442,310
Renewable Energy 2031 (%)	92.9%	88.4%	92.4%	88.2%
Avg. EnCompass System Cost Rate RAP ($/MWh)	$ 57.86	$ 59.14	$ 59.20	$ 60.25
Avg. EnCompass System Cost Rate Planning Period ($/MWh)	$ 83.05	$ 82.37	$ 85.64	$ 84.99

Notes: All portfolios in this table utilize the base load forecast, and seasonal PRMs and ELCCs. All capacity values are coincident w/ the July peak.

Figure 2.10-8 ADER Plan Capacity Expansion Graph – RAP



Results Discussion: ADER Plan vs. Base Plan

As indicated in Table 2.10-6, the ADER portfolio optimized using the SCC achieves 91.6% CO_2 reduction in 2031 from 2005 levels. This reduction is slightly lower than the Base portfolio with the SCC (92%) and notably higher than the ADER portfolio optimized using $0 per ton of CO_2, which achieves an 87.1% reduction.

The ADER portfolio with the SCC adds the same amount of dispatchable resources, 248 MW fewer renewable resources, and 200 MW more storage resources during the RAP than the Base portfolio with the SCC. Thus, in this analysis incremental ADER was found to largely replace renewables and storage, not gas.

Regarding the cost differences, the ADER portfolio with the SCC's PVRR is approximately $443M higher during the RAP than the Base portfolio with the SCC, a cost difference which widens to $2,091M through the end of the planning period. Using $0 per ton of CO_2, the ADER portfolio is $391M more in the RAP and $2,181M more over the planning period.

The ADER portfolios selected between 350-1,350 MW of long duration energy storage during the RAP, and both ADER portfolios selected between approximately 6,170-6,250 MW of long duration energy storage and 18-25 MW of hydrogen electrolyzers through the end of the planning period.

In addition to the Company's effort in this JTS to model the proxy transmission cost of $350/kW, the Company's Transmission Planning group conducted a parallel, first-of-a-kind transmission power flow study specifically for an ERP. The purpose of this JTS Transmission Study, which we discuss in Section 2.13 below, is to evaluate the requirements for maintaining transmission system reliability given a set of hypothetical JTS portfolios.

The intent of including the ADER portfolios in both the generation and transmission analyses is to quantify both the benefits that ADERs provide to the generation portfolio, as well as the ability to delay or avoid transmission costs. Due to timing differences (the transmission study had to commence long before the final EnCompass results were available), the total composition of the portfolios are not identical, but the additional 900MW of ADERs are the same, making the comparisons instructive. The customer-sited ADER resources were modeled in both studies as being on the unconstrained side of the Denver Metro constraint. In line with this assumption, the Company did not apply the $350/kW transmission adder in EnCompass to generic ADER resources like it did to all other generic resources, which we discuss Section 2.11 below. Despite this assumption, both the ADER portfolio with the SCC and the ADER portfolio with $0 per ton of CO_2 have PVRRs $443M and $391M higher than the Base portfolios with the SCC and $0 per ton of CO_2 during the RAP, respectively, which suggests any financial benefits from ADERs would be seen in the transmission analysis and would need to be compared to these generation cost increases to determine if the ADERs are overall economic or not.

Results: No New Gas Plan

Presented in Table 2.10-7 and Figure 2.10-9 are the detailed results for two No New Gas Plan portfolios of the 30 total JTS portfolio optimizations.

Each of the No New Gas portfolios shown below was optimized in Step 1 using the Base load forecast and the Seasonal PRM method. Regarding cost of carbon assumptions in Step 1, one of the No New Gas portfolios shown below was optimized using the SCC and the other using $0 per ton of CO_2.

The Present Value of Revenue Requirements ("PVRR") and EnCompass System Cost Rate 2031 values reported in Table 2.10-7 for each portfolio were developed from the 8760-dispatch of each portfolio over the 2025-2050 planning period.

Table 2.10-7 No New Gas Plan Detailed Results

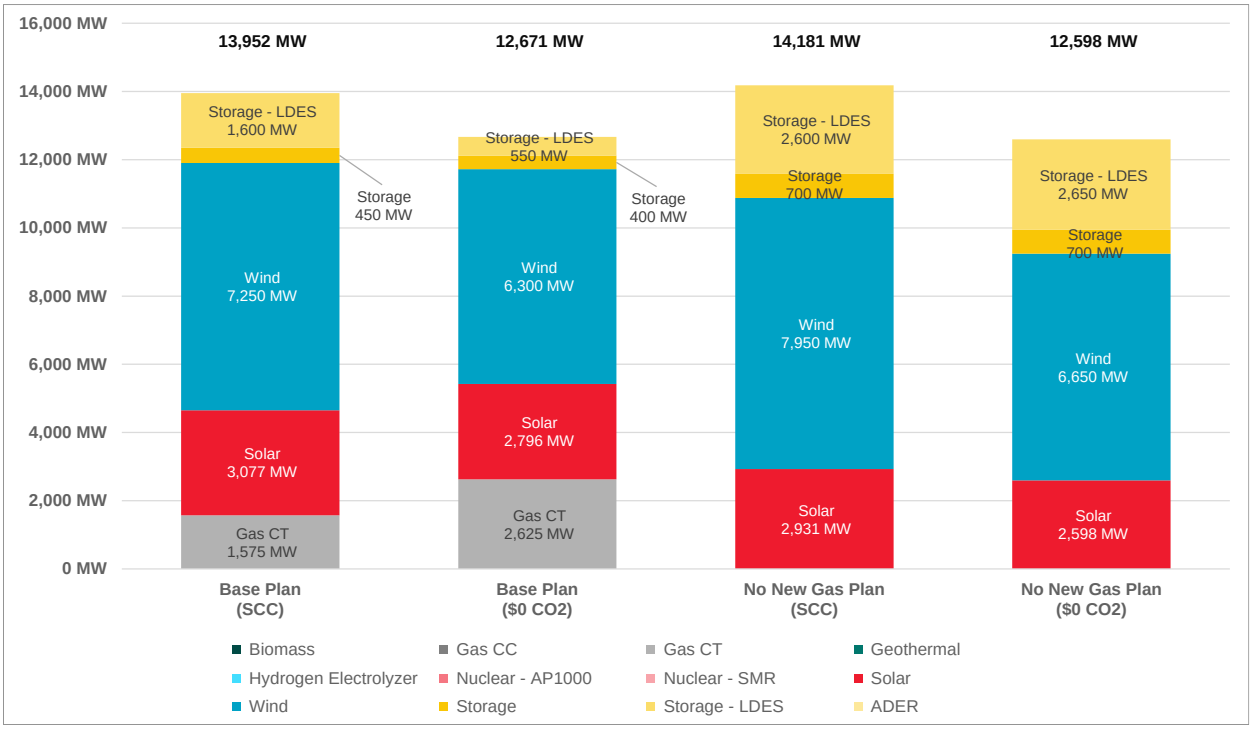
PSCo 2024 JTS Portfolios' Comparison

Resource Additions 2025-2031 (MW)	Base Plan (SCC)	Base Plan ($0 CO2)	No New Gas Plan (SCC)	No New Gas Plan ($0 CO2)
Biomass				
Gas CC				
Gas CT	1,575	2,625		
Geothermal				
Hydrogen Electrolyzer				
Nuclear - AP1000				
Nuclear - SMR				
Solar	3,077	2,796	2,931	2,598
Wind	7,250	6,300	7,950	6,650
Storage	450	400	700	700
Storage - LDES	1,600	550	2,600	2,650
ADER				
TOTAL Nameplate Capacity Additions (MW)	**13,952**	**12,671**	**14,181**	**12,598**
Dispatchable	1,575	2,625	-	-
Renewable	10,327	9,096	10,881	9,248
Storage	2,050	950	3,300	3,350
TOTAL Accredited Capacity (MW)	**4,432**	**4,307**	**4,118**	**4,049**
Present Value Revenue Requirement (PVRR)				
PVRR RAP 2025-2031 ($M)	$ 14,859	$ 15,238	$ 14,136	$ 13,897
PVRR 2025-2040 ($M)	$ 38,598	$ 38,289	$ 37,906	$ 37,579
PVRR Planning Period 2025-2050 ($M)	**$ 64,437**	**$ 63,939**	**$ 64,687**	**$ 64,499**
PVRR Delta vs. Base Plan ($M)	$ -	$ (498)	$ 250	$ 62
Emissions				
CO2 2025-2031 (M Tons)	46,724,934	53,057,713	44,411,795	49,757,378
CO2 2025-2050 (M Tons)	73,945,580	81,751,436	65,472,330	74,819,262
CO2 Delta vs. Base Plan 2025-2050 (M Tons)	-	7,805,857	(8,473,250)	873,682
CO2 Reduction 2031 from 2005 (%)	-92.0%	-87.1%	-94.8%	-91.3%
NPV CO2 at SCC 2025-2050 ($M)	$ 5,520	$ 6,115	$ 4,942	$ 5,634
NPV Methane at SCM 2025-2050 ($M)	$ 83	$ 97	$ 68	$ 83
TOTAL Present Value Societal Cost (PVSC) ($M)	**$ 70,039**	**$ 70,151**	**$ 69,696**	**$ 70,216**
PVSC Delta vs. Base Plan ($M)	$ -	$ 112	$ (343)	$ 177
Miscellaneous				
Natural Gas Burn 2025-2031 (GBtu)	362,404	463,689	323,374	402,531
Renewable Energy 2031 (%)	92.9%	88.4%	95.5%	92.2%
Avg. EnCompass System Cost Rate RAP ($/MWh)	$ 57.86	$ 59.14	$ 54.95	$ 53.85
Avg. EnCompass System Cost Rate Planning Period ($/MWh)	$ 83.05	$ 82.37	$ 84.40	$ 84.17

Notes: All portfolios in this table utilize the base load forecast, and seasonal PRMs and ELCCs. All capacity values are coincident w/ the July peak.

Corrected Table 2.10-7 No New Gas Plan Detailed PVRR Results	Base Plan (SCC)	Base Plan ($0 CO2)	No New Gas Plan (SCC)	No New Gas Plan ($0 CO2)	Corrected: No New Gas Plan (SCC)	Corrected: No New Gas Plan ($0 CO2)	Delta: No New Gas Plan (SCC)	Delta: No New Gas Plan ($0 CO2)
Present Value Revenue Requirement (PVRR)								
PVRR RAP 2025-2031 ($M)	$ 14,859	$ 15,238	$ 14,136	$ 13,897	$ 14,139	$ 13,900	$ 3	$ 3
PVRR 2025-2040 ($M)	$ 38,598	$ 38,298	$ 37,906	$ 37,579	$ 37,998	$ 37,671	$ 92	$ 92
PVRR Planning Period 2025-2050 ($M)	**$ 64,437**	**$ 63,939**	**$ 64,687**	**$ 64,499**	$ 64,848	$ 64,660	$ 161	$ 161
PVRR Delta vs. Base Plan ($M)	$ -	$ (498)	$ 250	$ 62	$ 411	$ 223	$ 161	$ 161

Figure 2.10-9 No New Gas Plan Capacity Expansion Graph – RAP



Results Discussion: No New Gas Plan vs. Base Plan

As indicated in Table 2.10-7, the No New Gas portfolio optimized using the SCC achieves a 94.8% CO_2 reduction in 2031 from 2005 levels, which is higher than the Base portfolio with the SCC (92%) and the No New Gas portfolio with $0 per ton of CO_2 (91.3%).

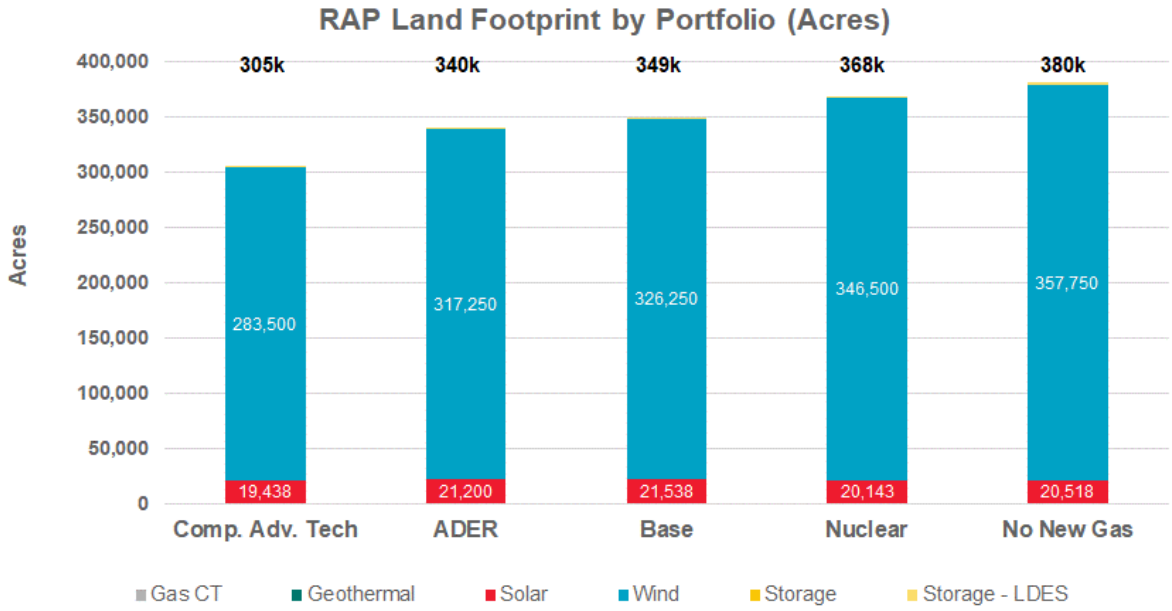
The No New Gas portfolio adds approximately 554 MW more renewable and 1,250 MW more storage resources than the Base portfolio with the SCC during the RAP and largely replaces the gas in the Base portfolios with LDES and shorter duration storage.

The No New Gas portfolio with the SCC's PVRR is approximately $72~~03~~M lower than the Base portfolio with the SCC during the RAP, but its PVRR is approximately $411~~250~~M higher through the end of the planning period. The RAP cost differences may be attributable to the lower amount of accredited capacity seen in the No New Gas portfolios, with each being 250-300 MW less during the RAP than their corresponding Base portfolio. Essentially, the No Gas portfolios are "less long" than the Base portfolios, although both exceed the minimum reserve margin seen in the L&R table by a significant amount.

Regarding new advanced technology generics, both No New Gas portfolios selected approximately 2,600 MW of long duration energy storage during the RAP and between approximately 10,000-10,300 MW of long duration energy storage through the end of the planning period.

While the No New Gas portfolio with the SCC achieves approximately 3% more CO_2 reduction in 2031 than the Base portfolio with the SCC, its 10,881 MW of renewable and 3,300 MW of storage resources require approximately 9% more land than the Base portfolio with the SCC, as shown in Figure 2.10-10 below.

Figure 2.10-10 RAP Land Footprint by Portfolio



Regarding portfolio curtailment, the No New Gas portfolio with the SCC curtails 975 GWh less energy than the Base portfolio with the SCC in 2031 but 16.6 TWh more than the Base portfolio with the SCC in 2050, as detailed in Figure 2.10-6 above in the discussion of the Advanced Technology portfolios.

Results: Low Load Portfolios

Presented in Table 2.10-8 and Figure 2.10-11 are the detailed results for six portfolios that used the Low load forecast sensitivity of the 30 total JTS portfolio optimizations.

The six portfolios shown below were optimized in Step 1 using the seasonal PRM method. Regarding cost of carbon assumptions in Step 1, one each of the Base, ADER, and No New Gas portfolios shown below were optimized using the SCC and the other Base, ADER, and No New Gas portfolios shown below using $0 per ton of CO_2.

The Present Value of Revenue Requirements ("PVRR") and EnCompass System Cost Rate 2031 values reported in Table 2.10-8 for each portfolio were developed from the 8760-dispatch of each portfolio over the 2025-2050 planning period.

Table 2.10-8 Low Load Portfolios Detailed Results

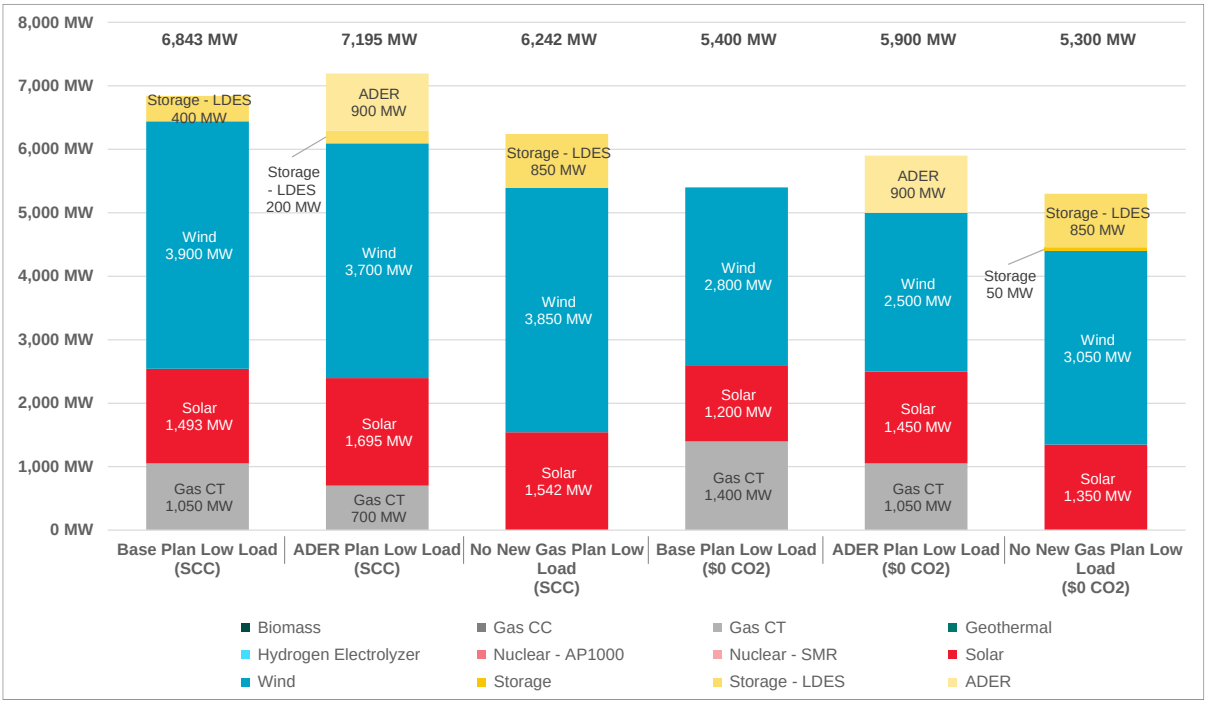
PSCo 2024 JTS Portfolios' Comparison

Resource Additions 2025-2031 (MW)	Base Plan Low Load (SCC)	ADER Plan Low Load (SCC)	No New Gas Plan Low Load (SCC)	Base Plan Low Load ($0 CO2)	ADER Plan Low Load ($0 CO2)	No New Gas Plan Low Load ($0 CO2)
Biomass						
Gas CC						
Gas CT	1,050	700		1,400	1,050	
Geothermal						
Hydrogen Electrolyzer						
Nuclear - AP1000						
Nuclear - SMR						
Solar	1,493	1,695	1,542	1,200	1,450	1,350
Wind	3,900	3,700	3,850	2,800	2,500	3,050
Storage						50
Storage - LDES	400	200	850			850
ADER		900			900	
TOTAL Nameplate Capacity Additions (MW)	**6,843**	**7,195**	**6,242**	**5,400**	**5,900**	**5,300**
Dispatchable	1,050	700	-	1,400	1,050	-
Renewable	5,393	5,395	5,392	4,000	3,950	4,400
Storage	400	1,100	850	-	900	900
TOTAL Accredited Capacity (MW)	**2,070**	**2,210**	**1,500**	**1,869**	**2,188**	**1,432**
Present Value Revenue Requirement (PVRR)						
PVRR RAP 2025-2031 ($M)	$ 13,676	$ 14,006	$ 13,302	$ 13,760	$ 13,952	$ 13,103
PVRR 2025-2040 ($M)	$ 31,100	$ 32,910	$ 30,216	$ 30,969	$ 32,676	$ 29,964
PVRR Planning Period 2025-2050 ($M)	**$ 51,174**	**$ 53,474**	**$ 51,392**	**$ 51,042**	**$ 53,383**	**$ 51,542**
PVRR Delta vs. Base Plan ($M)	$ -	$ 2,300	$ 218	$ (132)	$ 2,209	$ 368
Emissions						
CO2 2025-2031 (M Tons)	43,495,435	43,066,044	43,421,226	47,766,540	47,673,447	46,687,924
CO2 2025-2050 (M Tons)	70,554,730	69,560,319	64,008,776	76,363,437	75,724,381	71,871,806
CO2 Delta vs. Base Plan 2025-2050 (M Tons)	-	(994,411)	(6,545,954)	5,808,708	5,169,651	1,317,076
CO2 Reduction 2031 from 2005 (%)	-93.3%	-93.8%	-94.1%	-90.0%	-90.9%	-92.4%
NPV CO2 at SCC 2025-2050 ($M)	$ 5,243	$ 5,170	$ 4,824	$ 5,681	$ 5,637	$ 5,389
NPV Methane at SCM 2025-2050 ($M)	$ 77	$ 75	$ 66	$ 87	$ 86	$ 78
TOTAL Present Value Societal Cost (PVSC) ($M)	**$ 56,494**	**$ 58,719**	**$ 56,282**	**$ 56,809**	**$ 59,106**	**$ 57,009**
PVSC Delta vs. Base Plan ($M)	$ -	$ 2,225	$ (211)	$ 316	$ 2,613	$ 516
Miscellaneous						
Natural Gas Burn 2025-2031 (GBtu)	309,970	299,046	307,298	372,432	369,700	353,025
Renewable Energy 2031 (%)	91.8%	92.3%	92.9%	87.5%	88.3%	90.7%
Avg. EnCompass System Cost Rate RAP ($/MWh)	$ 61.65	$ 63.56	$ 59.85	$ 61.87	$ 63.12	$ 58.77
Avg. EnCompass System Cost Rate Planning Period ($/MWh)	$ 86.35	$ 90.21	$ 88.41	$ 86.10	$ 90.11	$ 88.84

Notes: All portfolios in this table utilize the low load forecast, and seasonal PRMs and ELCCs. All capacity values are coincident with the July peak.

Corrected Table 2.10-8 Low Load Portfolios Detailed PVRR Results						Corrected		Delta	
		Base Plan Low Load (SCC)	Base Plan Low Load ($0 CO2)	No New Gas Plan Low Load (SCC)	No New Gas Plan Low Load ($0 CO2)	No New Gas Plan Low Load (SCC)	No New Gas Plan Low Load ($0 CO2)	No New Gas Plan Low Load (SCC)	No New Gas Plan Low Load ($0 CO2)
Present Value Revenue Requirement (PVRR)									
	PVRR RAP 2025-2031 ($M)	$ 13,676	$ 13,760	$ 13,302	$ 13,103	$ 13,305	$ 13,106	$ 3	$ 3
	PVRR 2025-2040 ($M)	$ 31,100	$ 30,969	$ 30,216	$ 29,964	$ 30,308	$ 30,056	$ 92	$ 92
	PVRR Planning Period 2025-2050 ($M)	**$ 51,174**	**$ 51,042**	**$ 51,392**	**$ 51,542**	$ 51,553	$ 51,703	$ 161	$ 161
	PVRR Delta vs. Base Plan ($M)	$ -	$ (132)	$ 218	$ 368	$ 379	$ 529	$ 161	$ 161

Figure 2.10-11 Low Load Portfolios Capacity Expansion Graph – RAP



Results Discussion: Low Load Portfolios

The results of the Low Load sensitivities are difficult to compare to the results of the Base Load portfolios, as the difference in system size naturally introduces very large differences that are really related to size, overriding any other discernable differences. Thus, this section primarily compares the Low Load sensitivity portfolios amongst themselves.

As indicated in Table 2.10-8, the six Low Load portfolios optimized using the SCC and $0 per ton of CO_2 achieve between approximately 90% and 94% CO_2 reduction in 2031 from 2005 levels.

The Low Load ADER portfolio's PVRR is $330M higher than the Low Load Base portfolio with the SCC during the RAP and $2,300M higher through the end of the planning period. The Low Load No New Gas portfolio's PVRR is $~~374~~ 371M lower than the Low Load Base portfolio with the SCC during the RAP and $~~218~~ 379M higher through the end of the planning period.

Regarding the new advanced technology generics, four of the six Low Load portfolios selected between 200-850 MW of long duration energy storage during the RAP, as shown in Table 2.10-8, and all six selected between approximately 3,900-7,600 MW of long duration energy storage through the end of the planning period. The four Low Load Base and ADER portfolios added between 19-29 MW of hydrogen electrolyzers between the end of the RAP and the end of the planning period.

One significant point of comparison can be made between the Low Load and Base Load Forecast portfolios, and that is in effect on customer rates. The specific values of PVRR and PVSC for the Low Load portfolios are naturally less than the base forecast, simply due to the smaller system size being served. A more detailed and comprehensive rate forecast analysis was conducted by the Company's finance organization and discussed in the direct testimony of Company witness Mr. Jack Ihle, but we have included a metric in the modeling results tables that provides a simpler view of the impact on customer rates. Titled "Average EnCompass System Cost Rate", this value is simply the system costs represented in the EnCompass model divided by the system generation.

As can be seen in Table 2.10-9 below, both the 2025-2031 and 2025-2050 Average EnCompass System Cost Rate for every JTS scenario that uses the Base Case load forecast are notably lower than for the Low Load forecast. The JTS modeling clearly shows that portfolios planned and built to the Base Case load forecast will save customers money as compared to the Low Load forecast. This indicates that the higher load does not result in higher rates and customer costs, conversely the higher load spreads the costs over a larger customer base, lowering rates for everyone.

Table 2.10-9 2025-2031 and 2025-2050 Average EnCompass Cost Rate Results

Portfolio Cost Rate, 2025-2031 ($/MWh)	Base Load Forecast	Low Load Forecast	Delta (Base-Low)	
Base SCC	$57.86	$61.65	-$3.79	-7%
ADER SCC	$59.20	$63.56	-$4.37	-7%
No New Gas SCC	$54.95	$59.85	-$4.89	-9%
Base $0CO2	$59.14	$61.87	-$2.73	-5%
ADER $0CO2	$60.25	$63.12	-$2.87	-5%
No New Gas $0CO2	$53.85	$58.77	-$4.92	-9%

Portfolio Cost Rate, 2025-2050 ($/MWh)	Base Load Forecast	Low Load Forecast	Delta (Base-Low)	
Base SCC	$83.05	$86.35	-$3.30	-4%
ADER SCC	$85.64	$90.21	-$4.57	-5%
No New Gas SCC	$84.40	$88.41	-$4.00	-5%
Base $0CO2	$82.37	$86.10	-$3.73	-5%
ADER $0CO2	$84.99	$90.11	-$5.12	-6%
No New Gas $0CO2	$84.17	$88.84	-$4.67	-6%

2.11 MODELING INPUTS AND ASSUMPTIONS

This Section summarizes the key inputs and assumptions used in the Company's Phase I modeling and as proposed to be used for Phase II modeling. Paragraph 43 of the USA approved by the Commission provides that with the exception of updating generic resource assumptions, the ELCC Study, the PRM study, DSM strategic issues assumptions, Renewable Energy Plan assumptions, the PacifiCorp East transmission assumptions (detailed in paragraph 66 of the USA), the inclusion of any transmission projects with filed or approved CPCNs for the Company, an updated assessment of the existing transmission system, and regional market-related assumptions based on updated data and known circumstances, the all-source competitive solicitation will utilize the modeling inputs and assumptions approved in the most recent Phase I ERP (i.e., the 2021 ERP & CEP) unless good cause is shown to modify the modeling inputs and assumptions.

Accordingly, the Company used good cause to update several inputs and assumptions approved in Phase I of the 2021 ERP & CEP for purposes of this 2024 JTS. For example, "good cause" to update an input or assumption includes circumstances in which values have changed based on the current best available information (e.g., gas price forecast) and changes to inputs and assumptions resulting from related regulatory proceedings (e.g., update to the Company's approved weighted average cost of capital from the most recent electric rate case). Consistent with past practice, the Company proposes to update the modeling inputs and assumptions as necessary, consistent with the Commission's Phase I Decision and prior to commencement of the Phase II competitive solicitation.

Capital Structure and Discount Rate

The rates shown in Table 2.11-1 are used to calculate the capital revenue requirements of generic resources. The after-tax WACC of 6.52% is also used as the discount rate to determine levelized cost calculations and the present value of modeled costs.

Table 2.11-1 Capital Structure

Discount Rate and Capital Structure				
	Capital Structure	Allowed Return	Before Tax Electric WACC	After Tax Electric WACC
Long-Term Debt	43.40%	4.01%	1.74%	1.31%
Common Equity	55.69%	9.30%	5.18%	5.18%
Short-Term Debt	0.91%	3.81%	0.03%	0.03%
Total			**6.95%**	**6.52%**

Gas Price Forecasts

To derive the forecast of monthly delivered gas prices at Henry Hub, the company uses a combination of market indicators such as NYMEX and long-term price forecasts published by highly respected, industry-leading sources such as Wood Mackenzie and

S&P Global. The forecast is NYMEX based for the first few years, and then it transitions into blending the NYMEX curve with the two vendor forecasts to develop a composite forecast. The company used the following weightings for each component at various time intervals:

Period	NYMEX	S&P Global	Wood Mackenzie
Balance of the year + 2 years	100%	0%	0%
Years 3 and Beyond	25%	37.5%	37.5%
	10 yr trendline extension		

The final years of the forecasts vary between sources; Wood Mackenzie and S&P Global provide data through 2050 and NYMEX through 2036. The company uses linear extrapolation to extend the data of each forecast as needed. The Henry Hub is also adjusted for regional basis differentials and specific delivery costs for each generating unit to develop final model inputs.

The annual average base gas prices are summarized in Table 2.11-2.

Table 2.11-2 Fuel and Market Price Inputs

	Fuel Price ($/MMBtu)		Market Price ($/MWh)			
Year	Coal	CIG RM	4C On-Peak	4C Off-Peak	Midway On-Peak	Midway Off-Peak
2025	$1.52	$3.20	$34.64	$34.22	$33.01	$31.22
2026	$1.55	$3.44	$35.24	$37.74	$35.49	$36.08
2027	$1.58	$4.01	$32.35	$36.75	$33.17	$35.43
2028	$1.63	$4.13	$28.88	$34.64	$30.38	$33.40
2029	$1.66	$3.90	$26.24	$33.16	$30.61	$33.51
2030	$1.73	$3.79	$24.26	$32.50	$28.78	$32.92
2031	$1.75	$3.77	$23.33	$32.29	$27.92	$32.49
2032	$1.80	$3.86	$25.21	$35.01	$28.94	$34.92
2033	$1.86	$4.06	$25.68	$36.91	$29.33	$36.62
2034	$1.92	$4.21	$25.85	$36.89	$29.27	$37.11
2035	$1.98	$4.24	$25.86	$37.05	$28.41	$36.66
2036	$2.03	$4.33	$26.56	$38.09	$28.84	$37.63
2037	$2.11	$4.46	$27.34	$38.85	$29.67	$39.02
2038	$2.16	$4.59	$27.77	$39.65	$30.13	$40.17
2039	$2.24	$4.75	$28.30	$40.58	$30.93	$41.02
2040	$2.30	$4.88	$29.63	$42.53	$32.66	$43.94
2041	$2.37	$5.08	$31.52	$44.33	$35.12	$46.45
2042	$2.44	$5.20	$31.74	$44.74	$36.06	$47.68
2043	$2.51	$5.32	$30.79	$43.91	$35.18	$47.71
2044	$2.58	$5.53	$30.24	$42.93	$35.27	$47.46
2045	$2.65	$5.68	$30.96	$44.82	$35.49	$49.09
2046	$2.73	$5.88	$30.65	$43.78	$35.20	$48.40
2047	$2.80	$6.19	$30.39	$44.12	$34.63	$48.29
2048	$2.88	$6.45	$29.77	$43.14	$34.02	$47.25
2049	$2.96	$6.76	$30.36	$44.15	$34.66	$48.00
2050	$3.04	$7.21	$31.10	$44.88	$34.79	$48.09

**Coal prices are delivered prices, while gas and market prices are hub prices.*

Firm Fuel Charges

The Company applied a levelized charge of $21/kW-yr to all new generic CT resources and $55/kW-yr for generic CC resources to represent an estimate of the fixed costs associated with acquiring firm fuel supply to these generators either through firm gas supply or fuel oil backup infrastructure. Following bid submittal in Phase II, the Company will review and estimate, as necessary, the firm fuel costs for proposed projects based on the bid characteristics.

Market Prices

In addition to resources that exist within Colorado, the Company has access to markets located outside its service territory. External markets modeled include Midway (representing markets to the Colorado Front Range and Wyoming areas), Four Corners (representing Western/Southwestern areas) and SPP (through the Lamar tie). The modeling currently does not include interactions through the Lamar due to the limited nature and typically higher cost of as-available transmission along this path.

To derive the forecast of monthly On and Off-peak electricity prices, the company uses a simple average of On- and Off-peak power price forecasts provided by Wood Mackenzie and S&P Global.

Annual average values for the Four Corners Market and Midway are summarized in Table 2.11-2 and have zero CO_2 cost assumptions.

Coal Price Forecasts

Coal price forecasts are developed using two major inputs: the current coal contract volumes and prices combined with current estimates of spot market coal volumes and prices. Typically, coal volumes and prices are under contract on a plant-by-plant basis for a one to five-year term with annual spot volumes and prices filling the estimated fuel requirements of the coal plant. To derive the forecast of coal prices at mine mouth, the company uses a simple average of long-term coal price forecasts provided by Wood Mackenzie and S&P Global. Layered on top of the coal prices are transportation charges, freeze control and dust suppressant, as required. The simple average annual coal price forecast is summarized in Table 2.11-2.

Planning Reserve Margin

As discussed in the planning reserve margin study (provided as Attachment ZM-1 to the Direct Testimony of Zachary Ming), in the 2024 JTS, the Company will utilize a Planning Reserve Margin of approximately 6% in the summer and 9-13% in the winter applied to the demand forecast. The specific values per year are shown below in Table 2.11-3

Table 2.11-3 Reserve Margin

Reserve Margin (%)	2024	2025	2026	2027	2028	2029	2030	2031
Summer	6.3%	6.4%	6.3%	6.4%	6.4%	6.4%	6.4%	6.3%
Winter	8.7%	9.0%	9.1%	10.4%	11.9%	13.3%	14.5%	13.3%

Surplus Capacity Credit

For each year in which the modeled portfolio includes firm generation capacity in excess of the planning reserve margin (i.e. the periods in which the Company is long capacity), surplus capacity will be credited at the equivalent cost of the generic CT up to an excess of 200 MW for all twelve months of the year. The value of the surplus capacity credit is shown below in Table 2.11-4.

Table 2.11-4 Surplus Capacity Credit

Surplus Capacity Credit	
Year	$/kw-yr
2025	$124.82
2026	$126.74
2027	$128.69
2028	$130.69
2029	$132.74
2030	$134.84
2031	$136.99
2032	$139.20
2033	$141.45
2034	$143.76
2035	$146.13
2036	$148.56
2037	$151.04
2038	$153.59
2039	$156.20
2040	$158.87
2041	$161.60
2042	$164.41
2043	$167.28
2044	$170.22
2045	$173.23
2046	$176.32
2047	$179.48
2048	$182.71
2049	$186.74
2050	$190.88

Seasonal Capacity Purchases

The Company made a generic Seasonal Capacity Purchase available in the Phase I modeling for 2024-2027 in recognition that new generic resources would be difficult to place in service prior to 2028 given the regulatory timing of this proceeding. If bids are received in Phase II with in-service dates and capacity that fully meet earlier capacity needs, this purchase will be removed from the model.

CO_2 Price Forecasts

Base modeling assumptions are either a \$0/ton CO_2 proxy price or the SCC. The SCC values utilized are shown in Table 2.11-5 below. The SCC values will be based upon the February 2021 update to the Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990, published by the Federal Interagency Working Group on Social Cost of Greenhouse Gases, and will use the 2.5 percent discount rate from that publication. The Company will use the values from the cited report, converted to dollars per short ton and expressed in nominal dollars.

Table 2.11-5 CO2 Cost Forecast

CO2 Costs ($ per short ton)		
Year	$0 CO2	SCC
2025	$0.00	$85.13
2026	$0.00	$88.63
2027	$0.00	$92.25
2028	$0.00	$96.00
2029	$0.00	$99.87
2030	$0.00	$103.88
2031	$0.00	$108.10
2032	$0.00	$112.46
2033	$0.00	$116.97
2034	$0.00	$121.64
2035	$0.00	$126.47
2036	$0.00	$131.46
2037	$0.00	$136.62
2038	$0.00	$141.96
2039	$0.00	$147.48
2040	$0.00	$153.19
2041	$0.00	$159.05
2042	$0.00	$165.11
2043	$0.00	$171.37
2044	$0.00	$177.83
2045	$0.00	$184.52
2046	$0.00	$191.43
2047	$0.00	$198.57
2048	$0.00	$205.94
2049	$0.00	$213.56
2050	$0.00	$221.44

Methane Price Forecast

Societal costs (PVSC) will include the social cost of methane ("SCM") to the natural gas fuel supply to account for upstream methane leakage and methane emissions from combustion. As with the SCC described above, the Company will utilize the federal government's most recent assessment of the SCM (February 2021), using the value calculated at a 2.5 percent discount rate. Converted to nominal dollars pers short ton, the SCM value begins at $1771.92/short ton in 2020.

To estimate upstream methane emissions, the Company will utilize the methodology and assumptions similar to those provided by Guidehouse Inc. in Proceeding No. 22A0309EG. The Company will assume a methane leakage rate of 0.25% (similar to the 0.2089% system leakage rate from Guidehouse Inc. and consistent with the range of methane leakage rates required in the Phase I Decision), and a conversion rate of 47,790,860 Btu per short ton CH4, derived from the U.S. Environmental Protection Agency (EPA). To estimate methane emissions from combustion, the Company will assume the U.S. EPA's emissions factor of 2.3 pounds of CH4 per million standard cubic feet of natural gas fired.

Inflation / Construction Escalation Rates

The inflation rate used for construction (capital) costs, non-fuel variable O&M, fixed O&M and any other escalation factor related to general inflationary trends is from the Corporate Assumptions Memo. This rate is 2.50% and will be applied throughout the entire planning period as a base assumption.

Demand Response Forecasts

For purposes of determining resource need the Company has used the approved demand response and electric energy savings goals from the Commission's decision (Decision No. C23-0413) in the 2022 DSM Strategic Issues proceeding (Proceeding No. 22A-0309EG). Table 2.11-6 reflects the approved demand response goals.

Table 2.11-6 Demand Response Goals (MW)

Demand Response (DR)	2024	2025	2026
Summer DR Goal	630	651	675
Winter DR Goal	290	301	322

Table 2.11-7 Demand Response Goals (MW)

Demand Response (MW)					
	Max Capacity		Accredited Capacity		
Year	Summer	Winter	Annual PRM	Seasonal PRM Summer	Seasonal PRM Winter
2025	651	301	332	352	80
2026	675	322	316	335	79
2027	735	412	353	372	111
2028	787	456	326	341	123
2029	832	482	381	387	155
2030	872	509	425	409	182
2031	897	538	371	417	193
2032	923	567	382	429	203
2033	950	595	393	442	214
2034	977	624	404	454	224
2035	1000	650	414	465	233
2036	1020	673	422	475	242
2037	1045	696	432	486	250
2038	1066	718	441	496	258
2039	1093	743	452	508	267
2040	1115	765	461	519	274
2041	1137	788	470	529	283
2042	1158	807	479	539	290
2043	1175	813	486	546	292
2044	1193	830	494	555	298
2045	1217	851	503	566	305
2046	1235	869	511	574	312
2047	1252	888	518	583	319
2048	1269	900	525	590	323
2049	1286	915	532	598	329
2050	1304	934	539	606	335

Demand Response (MW)					
	Max Capacity		Accredited Capacity		
Year	Summer	Winter	Annual PRM	Seasonal PRM Summer	Seasonal PRM Winter
2025	651	301	332	352	80
2026	675	322	316	335	79
2027	735	412	353	372	111
2028	787	456	326	341	123
2029	832	482	381	387	155
2030	872	509	425	409	182
2031	897	538	409	417	192
2032	923	567	419	427	202
2033	950	595	431	438	211
2034	977	624	441	449	220
2035	1000	650	451	459	228
2036	1020	673	459	467	236
2037	1045	696	469	477	243
2038	1066	718	478	486	250
2039	1093	743	489	497	258
2040	1115	765	498	506	265
2041	1137	788	507	515	273
2042	1158	807	516	523	279
2043	1175	813	522	530	281
2044	1193	830	530	538	286
2045	1217	851	539	547	293
2046	1235	869	547	555	299
2047	1252	888	554	562	305
2048	1269	900	561	569	309
2049	1286	915	568	576	314
2050	1304	934	575	583	320

Transmission Network Upgrade Costs

Estimates of transmission network upgrades costs for the Phase I generic resources are included in the generic resource cost estimates. For Phase II, transmission network upgrade costs include: (1) those within an existing switching station or substation ("station") or the creation of a new interconnection station, and (2) those outside the interconnection station. In Phase II, the Company will allocate the first type of transmission network upgrade costs fully to the proposed bid(s) requiring those upgrades. The second type of costs will be allocated on a MW pro-rata share of upgrades needed for each individual bid for Phase II analyses purposes. However, the Company will not assign transmission network upgrade costs to projects that utilize existing transmission capacity or that utilize transmission projects for which the Company has been granted a

CPCN at the time of the bid evaluation or Commission approval of a portfolio of transmission expansion projects. See Sections 3.6 and Appendix C in the Volume 3 Request for Proposal documents for additional process details.

Transmission Interconnection Costs

Estimates of transmission interconnection costs for the Phase I generic resources are included in the generic resource cost estimates. Following bid submittal in a Phase II competitive solicitation the Company will review and estimate, as necessary, both the developer-borne and the transmission-provider-borne costs for proposed projects. See Sections C.3 and C.5 and Appendix C in the Volume 3 Request for Proposal documents for additional process details.

Generation Capacity Credit for Wind Resources

Wind resources existing at the start of 2024 receive 13.4% of generation capacity credit in Phase I and Phase II modeling based on the Company's 2024 RA Study. For Phase I modeling purposes, incremental, generic wind resources received generation capacity credit as shown in Table 2.11-8.

Table 2.11-8 Phase I 2031 Incremental Wind ELCC (%) Assumptions

Generic Wind ELCC	
Summer	
0-500 MW	16%
500-2000 MW	14%
2000-3000 MW	12%
3000-4000 MW	11%
Winter	
0-500 MW	16%
500-2000 MW	9%
2000-4000 MW	5%

For initial Phase II portfolio selection purposes, individual, incremental wind generation resources will receive generation capacity credit consistent with the proposed nameplate capacity and ERZ as found in the Company's 2024 RA Study. A table of this information (found in Table 5-14 of the 2024 RA Study) is provided in Table 2.11-9. The Company will interpolate between Incremental MW as shown in Table 2.11-9 to accommodate actual Phase II proposals.

Table 2.11-9 Phase II 2031 Incremental Wind ELCC (%) Assumptions by ERZ

Incremental MW	Summer				
	ERZ-1	ERZ-2	ERZ-3	ERZ-4	ERZ-5
0-500	20%	11%	13%	21%	21%
500-1000	18%	7%	18%	24%	14%
1000-2000	13%	6%	7%	18%	15%
2000-3000	6%	5%	10%	13%	11%
3000-4000	5%	6%	3%	9%	10%
Incremental MW	**Winter**				
	ERZ-1	ERZ-2	ERZ-3	ERZ-4	ERZ-5
0-500	4%	11%	18%	25%	20%
500-1000	7%	7%	13%	18%	16%
1000-2000	6%	5%	4%	12%	6%
2000-3000	2%	3%	3%	8%	5%
3000-4000	4%	5%	3%	6%	3%

As the 2024 RA Study documented the impact that generation technology, penetration, and geographic diversity has on portfolio ELCC, the actual ELCC afforded any particular bid in final Phase II modeling and portfolio selection will likely differ from the values shown in Table 2.11-9; a map illustrating the relative geographic areas of each of the five ERZs shown in the Table is included in Figure 2.5-3 in Section 2.5 above. See Section 2.13 for further discussion of the process through which portfolio ELCC will be determined in Phase II modeling.

Generation Capacity Credit for Solar Resources

Utility solar resources that are existing at the start of 2023 or planned approved CEP bids receive 27.9% of generation capacity credit in Phase I and Phase II modeling based on the Company's 2024 RA Study. For Phase I modeling purposes, incremental and generic utility solar resources received generation capacity credit as shown in Table 2.11-10.

Table 2.11-10 Phase I 2031 Incremental Generic Solar ELCC (%)

Generic Utility Solar ELCC	
Summer	
0-500 MW	16%
500-2000 MW	11%
2000-3000 MW	7%
3000-4000 MW	6%
Winter	
0-2000 MW	0%
2000-4000 MW	3%

For initial Phase II portfolio selection purposes, individual, incremental utility solar generation resources will receive generation capacity credit consistent with the proposed nameplate capacity and solar zone as found in the Company's 2024 RA Study. A table of this information (found in Table 5-12 of the 2024 RA Study provided as Attachment ZM-1) is provided in Table 2.11-11. The Company will interpolate between Incremental MW as shown in Table 2.11-11 to accommodate actual Phase II proposals.

Table 2.11-11 Phase II 2031 Incremental Solar ELCC (%) by Solar Resource Zone

Incremental MW	Summer					
	SE	SFR	SLV	MTN	NFR	WS
0-500	16%	14%	16%	22%	14%	14%
500-1000	9%	9%	11%	19%	9%	9%
1000-2000	13%	9%	8%	12%	7%	5%
2000-3000	6%	7%	8%	3%	8%	5%
3000-4000	4%	7%	3%	3%	7%	5%
Incremental MW	**Winter**					
	SE	SFR	SLV	MTN	NFR	WS
0-500	0%	0%	0%	6%	0%	6%
500-1000	0%	0%	0%	0%	0%	2%
1000-2000	0%	3%	3%	2%	0%	2%
2000-3000	0%	2%	3%	1%	2%	0%
3000-4000	2%	1%	2%	0%	0%	0%

As the ELCC study documented the impact that generation technology, penetration, and geographic diversity has on portfolio ELCC, the actual ELCC assigned to any particular bid in final Phase II modeling will likely differ slightly from the values shown in Table 2.11-

11. See Section 2.13 for further discussion of the process through which portfolio ELCC will be determined in Phase II modeling.

Generation Capacity Credit for Hydro and Storage Resources

Based on the Company's most recent ELCC study, in Phase I and Phase II modeling: (1) existing hydro generation resources receive 55.4%, (2) the Company's existing Cabin Creek pumped hydro facility receives 91.7%, and (3) the storage components of solar hybrid facilities existing at the start of 2023 receive 60.4% in generation capacity credit. Generic 4- and 8-hour duration battery resources modeled in Phase I received generation capacity credit as shown in Table 2.11-12.

Table 2.11-12 Phase I and II 2031 Incremental Storage ELCC (%) by Duration

Incremental MW	Summer	
	4hr	8hr
0-500	60%	91%
500-1000	46%	67%
1000-2000	36%	48%
2000-3000	18%	17%
3000-4000	18%	13%
Incremental MW	**Winter**	
	4hr	8hr
0-500	35%	63%
500-1000	38%	51%
1000-2000	22%	34%
2000-3000	19%	23%
3000-4000	17%	20%

For initial Phase II portfolio selection purposes, incremental storage resources will receive generation capacity credit consistent with the ELCC values in the table above. These values will apply to both standalone storage proposals and the storage component of renewable hybrid proposals.

As the ELCC study documented the impact that generation technology, penetration, and geographic diversity has on portfolio ELCC, the actual ELCC afforded any particular storage bid in final Phase II modeling will likely differ from the values shown in Table 2.11-12. See Section 2.13 for further discussion of the process through which portfolio ELCC will be determined in Phase II modeling.

Generation Capacity Credit for Dispatchable Resources

ELCC for dispatchable resources is a function of size and outage rate. The accredited values that will be used for Phase II bids are shown below in Table 2.11-13.

Table 2.11-13 Phase II Generation Capacity Credit for Dispatchable Resources

Tranche Size MW	0	50	100	200	300	750
FOR 2%	-	98%	98%	98%	98%	90%
FOR 5%	-	95%	95%	95%	91%	71%
FOR 7%	-	93%	93%	93%	88%	64%
FOR 10%	-	90%	90%	88%	85%	55%
FOR 20%	-	80%	80%	80%	76%	41%

Resource Acquisition Period

Paragraph 15 of the USA provides that all 2029 and 2030 resource needs identified will be filled through the 2024 JTS, which will utilize a RAP of 2024 through end of year 2031. See also Section 2.1.

Planning Period

Planning Period means the future period for which a utility develops its ERP and the period over which net present value of revenue requirements for resources are calculated. Pursuant to Rule 3602(k), the planning period is 20 to 40 years and begins from the date the utility files its plan with the Commission. The proposed 2024 JTS planning period is from 2024 to 2050. See also Section 2.1.

SO_2 Effluent Costs and Allocations

SO_2 is controlled through the Acid Rain program in Colorado. Through this program, the Company has excess SO_2 allowances because of the use of low sulfur coal and scrubber retrofits at the Arapahoe, Cherokee, Hayden, and Valmont units. Therefore, the Company does not anticipate that it will have to purchase any allowances for SO_2 under current or reasonably foreseeable legislation. Therefore, the Company assigns no effluent costs or allocations to SO_2. SO_2 effluent costs (as measured in $/ton) will remain zero unless a major change in legislation occurs during the deliberation of the ERP.

NO_x Effluent Costs and Allocations

There is no trading program for sources of NO_x in Colorado; therefore, no cost is applied to NO_x emissions. The primary programs that reduce NO_x are the Regional Haze Rule through the application of the Best Available Retrofit Technology program, which seeks to achieve further reasonable progress towards long term visibility goals in Class I areas like national parks and wilderness areas. The Denver ozone State Implementation Plan ("SIP") is also another driver for NO_x reductions. As a result, the costs of NO_x reductions are embedded in capital and operating costs of the resources included in the SIP (e.g.,

the Selective Catalytic Reduction additions to Pawnee and Hayden). NO_x effluent costs (as measured in $/ton) will remain zero unless a major change in legislation occurs during the deliberation of the ERP.

Mercury Effluent Costs and Allocations

Mercury is also controlled as a command and control rule through the Colorado Mercury Rule. Therefore, there is no cap and trade for mercury either and effluent costs and allocations will be assigned a zero cost in the Phase I alternative plan analysis. As with SO_2 and NO_x, costs associated with controlling these emissions were captured in the resource costs. Mercury effluent costs (as measured in $/ton) will remain zero unless a major change in legislation occurs during the deliberation of the ERP.

Spinning Reserve Requirement

Spinning Reserve is the on-line reserve capacity that is synchronized to the grid to maintain system frequency stability during contingency events and unforeseen load swings. The level of spinning reserve modeled was consistent with the NWPP requirements. The cost of spinning reserve is inherently embedded in the EnCompass model by assigning a spin requirement and the spinning capability of each resource.

Emergency Energy Costs

Emergency Energy Costs are included in the EnCompass model if there are not enough resources available to meet energy requirements. In the model, the cost was set at an arbitrary very high cost ($100,000 / MWh) to ensure the model makes every effort to avoid emergency energy (which is synonymous with curtailed firm load). Emergency energy costs occur only in rare instances; however, it does appear in some plans in very small amounts. To represent the ability of the Company to procure non-economic reliability purposes in critical times as well as to ensure large swings in plan costs are not created by emergency energy costs, the first 500 MW of the emergency energy was classified as reliability purchases. For purposes of determining NPV both the reliability purchases and residual emergency energy (if any) were replaced in production costing scenarios with values of $2,000/MWh ($2020) escalating at 2%.

Owned Unit Modeled Operating Characteristics and Costs

Company-owned units were modeled based on their tested operating characteristics and historical or projected costs. Below is a list of operating and cost inputs for each Company-owned resource:

a. Maximum Capacity
b. Minimum Capacity Rating
c. Seasonal Deration
d. Heat Rate Profiles
e. Variable O&M

f. Fixed O&M
g. Maintenance Schedule
h. Forced Outage Rate
i. Emission rates
j. Contribution to spinning reserve
k. Fuel prices
l. Fuel delivery charges

Thermal PPA Operating Characteristics and Costs

PPA are modeled based upon their tested operating characteristics and contracted costs. Below is a list of operating and cost inputs for each thermal purchase power contract:

a. Contract term
b. Maximum Capacity
c. Minimum Capacity Rating
d. Seasonal Deration
e. Heat Rate Profiles
f. Energy Schedule
g. Capacity Payments
h. Energy Payments
i. Maintenance Schedule
j. Forced Outage Rate
k. Emission rates
l. Contribution to spinning reserve
m. Fuel prices
n. Fuel delivery charges

Renewable Energy PPA Operating Characteristics and Costs

PPAs are modeled based upon their tested operating characteristics and contracted costs. Below is a list of operating and cost inputs for each renewable energy purchase power contract:

a. Contract term
b. Name Plate Capacity
c. Accredited Capacity
d. Annual Energy
e. Hourly Patterns
f. Capacity Payments
g. Energy Payments
h. Integration Costs
i. Emission rates

Load Forecast

A discussion of the load forecast and methodology is available in Section 2.2, and a discussion of the resource need assessment is provided in Section 2.9. Table 2.11-14 below summarizes the Company's Phase I projection of resource capacity need.

The forecast shown in Tables 2.11-15 and 2.11-16 further below do not include the impact of DG solar, as DG solar is modeled as a resource, not a load modifier.

Table 2.11-14 Public Service Resource Capacity Need Forecast

Capacity Need	2024	2025	2026	2027	2028	2029	2030	2031
Summer (MW)	378	646	534	237	631	1,517	2,253	3,177
Winter (MW)	-	-	787	386	1,052	1,301	2,106	3,348

Table 2.11-15 Demand and Energy Forecast

Low Forecast				Base Forecast		
Year	Peak Season	Demand (MW)	Energy (GWh)	Peak Season	Demand (MW)	Energy (GWh)
2025	Summer	7,288	35,373	Summer	7,327	35,762
2026	Summer	6,968	35,102	Summer	7,039	35,852
2027	Summer	7,112	36,311	Summer	7,348	38,383
2028	Summer	7,155	37,364	Summer	7,732	42,132
2029	Summer	7,389	38,757	Summer	8,437	47,251
2030	Summer	7,595	40,542	Summer	9,123	52,943
2031	Summer	7,799	42,270	Summer	9,720	57,938
2032	Summer	8,000	44,149	Summer	10,141	61,787
2033	Summer	8,222	45,866	Summer	10,464	64,362
2034	Summer	8,442	47,566	Summer	10,736	66,614
2035	Summer	8,633	49,203	Summer	10,963	68,669
2036	Summer	8,796	50,845	Summer	11,173	70,784
2037	Summer	8,987	52,296	Summer	11,405	72,540
2038	Summer	9,150	53,769	Summer	11,596	74,309
2039	Summer	9,351	55,226	Winter	11,846	76,049
2040	Winter	9,521	56,723	Winter	12,208	77,894
2041	Winter	9,760	58,010	Winter	12,544	79,410
2042	Winter	9,954	59,335	Winter	12,828	81,018
2043	Winter	9,978	60,397	Winter	12,955	82,324
2044	Winter	10,178	61,823	Winter	13,194	84,021
2045	Winter	10,461	63,012	Winter	13,515	85,342
2046	Winter	10,681	64,241	Winter	13,775	86,763
2047	Winter	10,896	65,450	Winter	14,032	88,163
2048	Winter	11,015	66,736	Winter	14,187	89,709
2049	Winter	11,337	67,756	Winter	14,394	90,869
2050	Winter	11,659	68,900	Winter	14,686	92,232

Base Distributed Energy Resource Forecasts

The distributed solar and Community Solar Gardens inputs are based on the most recent Company forecasts. Distributed Solar is modeled assuming a degradation of half a percent annually in generation. Community Solar Gardens are modeled assuming a degradation of half a percent annually in generation, and a 20-year service life.

Table 2.11-16 Distributed Solar Maximum Capacity Forecast

Distributed Solar - July Max Capacity (MW)			
Year	Behind the Meter	Community Gardens	Total
2025	664	315	979
2026	752	357	1,109
2027	834	449	1,283
2028	917	564	1,481
2029	979	753	1,732
2030	1,083	847	1,930
2031	1,185	940	2,126
2032	1,304	991	2,295
2033	1,394	1,041	2,435
2034	1,453	1,088	2,542
2035	1,528	1,133	2,661
2036	1,629	1,177	2,806
2037	1,730	1,225	2,956
2038	1,803	1,263	3,066
2039	1,867	1,297	3,164
2040	1,893	1,320	3,213
2041	1,997	1,355	3,351
2042	2,105	1,376	3,481
2043	2,229	1,400	3,629
2044	2,297	1,362	3,659
2045	2,330	1,339	3,669
2046	2,415	1,348	3,763
2047	2,547	1,311	3,858
2048	2,712	1,254	3,965
2049	2,821	1,129	3,951
2050	2,924	1,090	4,014

Table 2.11-17 Distributed Solar Accredited Capacity Forecast

Distributed Solar - Accredited Capacity (MW)									
	Annual PRM			Seasonal PRM - Summer			Seasonal PRM - Winter		
Year	Behind the Meter	Community Gardens	Total	Behind the Meter	Community Gardens	Total	Behind the Meter	Community Gardens	Total
2025	120	44	164	144	52	196	5	2	6
2026	121	44	165	150	55	206	10	4	14
2027	137	57	195	149	62	212	22	9	31
2028	131	62	193	113	54	166	34	16	51
2029	90	52	142	101	59	160	20	12	32
2030	99	68	167	107	72	179	0	0	0
2031	105	81	186	127	92	219	0	0	0
2032	114	89	203	136	100	236	0	0	0
2033	123	97	220	145	108	253	0	0	0
2034	132	105	236	154	115	269	0	0	0
2035	139	112	251	161	123	284	0	0	0
2036	146	119	265	168	130	298	0	0	0
2037	152	127	279	175	137	312	0	0	0
2038	159	132	291	181	143	324	0	0	0
2039	166	135	301	188	145	334	0	0	0
2040	173	137	310	195	148	343	0	0	0
2041	181	140	320	203	151	353	0	0	0
2042	190	142	331	212	152	364	0	0	0
2043	198	144	341	220	155	374	0	0	0
2044	205	140	346	228	151	379	0	0	0
2045	214	138	352	236	149	385	0	0	0
2046	222	139	361	244	150	394	0	0	0
2047	232	136	368	254	147	401	0	0	0
2048	241	131	372	264	142	405	0	0	0
2049	248	111	359	270	122	392	0	0	0
2050	253	105	358	275	116	391	0	0	0

Carbon Caps

The Company assumes the following annual carbon caps in all scenarios, as shown in the table 2.11-18 below.

Table 2.11-18 Carbon Dioxide Cap

CO2 Ton Cap	
Year	Tons
2026	8,590,842
2027	8,590,842
2028	8,590,842
2029	8,590,842
2030	5,486,746
2031	5,486,746
2032	5,486,746
2033	2,743,373
2034	2,743,373
2035	2,743,373
2036	2,743,373
2037	2,743,373
2038	2,743,373
2039	2,743,373
2040	2,743,373
2041	2,469,036
2042	2,194,698
2043	1,920,361
2044	1,646,024
2045	1,371,686
2046	1,097,349
2047	823,012
2048	548,675
2049	274,337
2050	-

Market Purchases and Sales Carbon Rate

In order to estimate emissions rates associated with market purchases, the Company assumes an annual average carbon emissions pounds/MWh rate, as shown in the table below. These estimates were developed through the collaborative process coordinated by the AQCC.

For market sales, the carbon tons are deducted from the Company's emissions using the annual average of the system's carbon intensity on a scenario-by-scenario and year-by-year basis.

Table 2.11-19 Market Purchase CO2 Rate

Market Purchase CO2 Rate													
	2025	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
lbs/MWh	450	450	450	450	450	450	450	450	450	450	450	450	450
	2038	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**
lbs/MWh	450	450	450	405	360	315	270	225	180	135	90	45	0

Cherokee 4 Minimum Capacity Factor update

In reviewing and analyzing five years of Cherokee 4's generation output data from the beginning of 2019 to the end of 2023, the Company decided to update the unit's minimum capacity factor for JTS modeling to approximately 30%. The Company arrived at this value by averaging the unit's capacity factor for years 2019, 2020, 2021, and 2023. The Company excluded the unit's 2022 capacity factor from the average because it was a notably higher outlier as compared to the other four years.

Generic Resources Cost and Performance

A "generic resource" means the representation of a potential new supply-side utility resource for benchmarking or modeling purposes that embodies the estimated cost and performance of the represented technology without regard to a specific site location. A generic resource is generally represented by capacity (nameplate and summer rating or incremental capacity credit); capital and fixed O&M costs; transmission interconnection and grid upgrade costs; variable O&M costs (fuel and heat rates); book (useful) life; ramp rates and production curves; forced outage rates; typical annual maintenance requirements; emission rates; and indicative pricing (levelized costs).[14]

Generic solar, wind, 4-hour battery storage, 8-hour battery storage, gas-fired thermal resources, ADERs, nuclear AP1000, nuclear small modular reactor ("SMR"), enhanced geothermal, LDES, biomass, and hydrogen electrolyzers were available to the EnCompass model when creating Phase I alternative plans both within the RAP and post-RAP periods. For purposes of the Phase I modeling, costs for most generics were taken from the 2023 NREL Annual Technology Baseline ("ATB").[15]

For portfolio selection in the Phase II competitive acquisition, generic resources are replaced with costs and performances of actual proposed projects.

[14] Grid upgrade costs are not included in the generic costs presented; grid upgrade costs are site-specific.
[15] Available at: Data | Electricity | 2023 | ATB | NREL

Solar Generic

Generic costs for a 100 MW PV utility solar generic were obtained from the ATB. For purposes of modeling, the solar generic was represented using a 50 MW size/block. The Company selected data for a Class 10 utility-scale PV resource and a Moderate Technology Scenario. Cost and performance values are shown in Table 2.11-26 consistent with how results are presented in the ATB; costs in the Table are levelized costs based on the in-service year over a 30-yearbook life. Annual NCF was adjusted to match a Colorado resource (29% with annual degradation) and Projects were given the base Production Tax Credit ("PTC") through the expected lifetime of IRA eligibility.

Wind Generic

Generic costs for a 200 MW land-based wind generic were obtained from the ATB. For purposes of modeling, the wind generic was represented using a 50 MW size/block. The Company selected data for a Class 3, Technology 1 wind resource and a Moderate Technology Scenario. Cost and performance values are shown in Table 2.11-26 consistent with how results are presented in the ATB; costs in the Table are levelized costs based on the in-service year over a 30-yearbook life. Annual NCF was set to 42.1% for all years and projects were given the base Production Tax Credit ("PTC") through the expected lifetime of IRA eligibility.

4-Hour and 8-Hour Duration Battery Storage Generics

Generic costs and performance for 4 and 8-hour duration storage resources were obtained from the 2023 NREL ATB. The ATB represents cost and performance for battery storage in the form of 4 and 8-hour utility-scale, lithium-ion battery systems with 15-year assumed lives. The ATB assumes an 85% round-trip efficiency. Overnight capital costs based on in-service year data from the ATB are presented in Table 2.11-21. For purposes of Phase I modeling, the battery generic was represented using a 50 MW size/block. Projects were modeled with a 30% ITC through the expected lifetime of IRA eligibility.

Gas-Fired Thermal Resource Generics

Gas-fired thermal resource generics include a clean fuel capable combustion turbine and a clean fuel capable 2x1 combined-cycle resource. The cost and performance specifications for the two thermal generics shown in Table 2.11-20 were provided by the Company's Energy Supply engineers based on values provided by its vendors. Levelized Cost by In-Service Year ~~Annual Economic Carrying Charges~~ shown in $/kW-mo terms in Table 2.11-25 for the two generics were calculated from data out of the EnCompass model.

Aggregated Distributed Energy Resources (ADERs) Generic

ADERs, also known as virtual power plants (VPPs), coordinate many dispersed customer resources to dispatch them as an aggregate generation or load flexibility resource. The

Company represented generic ADER resources using averages of the residential and commercial battery storage costs and performance data from the 2023 NREL ATB. Costs from the ATB are presented in Table 2.11-21. For purposes of Phase I modeling, the ADER generic was represented using a 50 MW size/block and assumed operating characteristics consistent with 4-hour Li-ion storage. Projects were modeled with a 30% ITC through the expected lifetime of IRA eligibility.

Nuclear AP1000 Generic

An AP1000 nuclear reactor is a large-scale, generation III nuclear unit equipped with advanced passive safety features. It is a dispatchable CFE generation resource. Generic costs for a 1,000 MW AP1000 generic were obtained from the 2023 NREL ATB. For purposes of modeling, the AP1000 generic was represented using a 1,000 MW size/block. The Company selected data for a Moderate Technology Scenario. Cost values are shown in Table 2.11-22. Projects were modeled with a 30% ITC through the expected lifetime of IRA eligibility.

Nuclear Small Modular Reactor (SMR) Generic

An SMR is a small-scale nuclear unit equipped with advanced passive safety features. It is a dispatchable CFE generation resource. Generic costs for a 300 MW SMR generic were obtained from the 2023 NREL ATB. For purposes of modeling, the SMR generic was represented using a 300 MW size/block. The Company selected data for a Moderate Technology Scenario. Cost values are shown in Table 2.11-22. Projects were modeled with a 30% ITC through the expected lifetime of IRA eligibility.

Enhanced Geothermal Generic

Enhanced geothermal systems use the latest drilling technologies to access geothermal resources more widely and cost-effectively. It is a dispatchable CFE generation resource. Generic costs for a 30 MW enhanced geothermal generic were obtained from the 2023 NREL ATB. For purposes of modeling, the enhanced geothermal generic was represented using a 50 MW size/block. The Company selected data for a near-field enhanced geothermal system (NF-EGS) binary resource and a Moderate Technology Scenario. Cost values are shown in Table 2.11-24. Projects were modeled with a 30% ITC through the expected lifetime of IRA eligibility.

Long-Duration Energy Storage Generic (LDES)

LDES is grid-scale energy storage that is capable of discharging for multiple days through periods of reduced wind and solar resources. It is a dispatchable CFE storage resource. Generic costs for a 100-hour iron air battery storage generic were obtained from a Form Energy White Paper filed publicly as part of Great River Energy's 2023-2037 IRP. Performance data for the generic was obtained from recent Southwest Public Service and Northern States Power Company IRPs, as well as from Form Energy, and assumes a 20-year useful life with a "replacement" at 10 years. The Company assumes a 45% round-

trip efficiency. Levelized fixed costs based on in-service year data are presented in Table 2.11-23. For purposes of Phase I modeling, the long duration energy storage generic was represented using a 50 MW size/block. Projects were modeled with a 30% ITC through the expected lifetime of IRA eligibility.

Biomass Generic

Biomass power plants burn biogenic feedstocks, such as switchgrass, to generate electricity. It is a dispatchable CFE generation resource. Generic costs for the biomass generic were obtained from the 2023 NREL ATB. For purposes of modeling, the biomass generic was represented using a 50 MW size/block. The Company selected data for a Moderate Technology Scenario. Cost values are shown in Table 2.11-23. Projects were assumed to be closed-loop and eligible for the base PTC through 2036.

Hydrogen Electrolyzer Generic

A hydrogen electrolyzer is a technology that uses electricity to split water into oxygen and hydrogen, capturing the hydrogen and making it available for use as a clean fuel. For Phase I modeling, the electrolyzer generic can produce hydrogen for combustion in the generic thermal fleet. Cost and performance data for the generic electrolyzer were obtained from the Company's internal team of technology experts. Costs for on-site storage of 120 hours of production were included in the generic costs. System infrastructure such as distribution networks or transportation were not modeled due to the inherent uncertainty on the need or costs for this support infrastructure, thus the costs would be indicative of production and storage at the plant site. Cost values are shown in Table 2.11-24. Projects were assumed to be eligible for the hydrogen tax credit through the expected lifetime of IRA eligibility.

Generic Transmission Interconnection Costs

All generic resources assume a $350/kW cost for transmission, except for ADERs and wind, solar, and storage resources built on the CPP.

Table 2.11-20 Generic Dispatchable Resource Cost and Performance

	Natural Gas-Fired Thermal Generics	
Resource	**Generic CT**	**Generic CC**
Technology	7F.05	7F.05
Cooling Type	Dry	Wet
Book life	25	25
Winter Peak Capacity (MW)	196	672
Summer Peak Capacity (MW)	175	657
Other Months Capacity (MW)	195	671
Duct Burners		Fired
Capital Cost ($000) 2024$	$183,711	$707,326
Transmission Adder ($000) 2024$	$68,600	$235,200
Total Capital ($000) 2024$	$252,311	$942,526
Capital Cost ($/kW) 2024$ (Summer MW)	$1,442	$1,435
Firm Fuel Costs (2024 $/kW-yr; summer MW)	$21	$55
Ongoing Capital Expenditures ($000-yr) 2024$	$1,461	$6,045
Fixed O&M Cost ($000/yr) 2024$	$767	$5,420
Variable O&M Cost ($/MWh) 2024$	$2.85	$2.26
Summer Heat Rate w/ duct burners (btu/kWh)		6,705
Summer Heat Rate 100% Loading (btu/kWh)	10,015	6,534
Summer Heat Rate 75% Loading (btu/kWh)	10,588	6,725
Summer Heat Rate 50% Loading (btu/kWh)	12,532	7,259
Summer Heat Rate 25% Loading (btu/kWh)	13,448	7,460
Winter Heat Rate w/ duct burners (btu/kWh)		6,697
Winter Heat Rate 100% Loading (btu/kWh)	9,768	6,545
Winter Heat Rate 75% Loading (btu/kWh)	10,223	6,682
Winter Heat Rate 50% Loading (btu/kWh)	12,042	7,150
Winter Heat Rate 25% Loading (btu/kWh)	12,882	7,350
Other Months Heat Rate w/ duct burners (btu/kWh)		6,669
Other Months Heat Rate 100% Loading (btu/kWh)	9,820	6,510
Other Months Heat Rate 75% Loading (btu/kWh)	10,257	6,647
Other Months Heat Rate 50% Loading (btu/kWh)	12,031	7,117
Other Months Heat Rate 25% Loading (btu/kWh)	12,844	7,309
Forced Outage Rate	4.0%	4.0%
Maintenance (weeks/yr)	2	3
CO2 Emissions (lbs/MMBtu)	117.0	117.0
SO2 Emissions (lbs/MWh)	0.0064	0.0039
NOx Emissions (lbs/MWh)	0.0915	0.0915
PM10 Emissions (lbs/MWh)	0.0402	0.0300
Mercury Emissions (lbs/MMWh)	0.0000	0.0000
Lowest stable operating Point (% of nameplate)	45.9%	46.5%
Normal ramp rate (MW/Min)	16	
Water use, Consumptive (gallons/MWh)	22	250

Table 2.11-21 Generic Costs for 4-hour, 8-hour, and ADER/VPP Storage

50MW 4HR Storage (15yr Life)		
Year	Overnight Capital Cost ($/kW)	FOM ($/kW-yr)
2028	$1,662	$42
2029	$1,642	$41
2030	$1,621	$41
2031	$1,635	$41
2032	$1,650	$41
2033	$1,664	$42
2034	$1,678	$42
2035	$1,692	$42
2036	$1,705	$43
2037	$1,718	$43
2038	$1,731	$43
2039	$1,743	$44
2040	$1,755	$44
2041	$1,766	$44
2042	$1,776	$44
2043	$1,786	$45
2044	$1,796	$45
2045	$1,804	$45
2046	$1,812	$45
2047	$1,820	$45
2048	$1,826	$46
2049	$1,832	$46
2050	$1,837	$46

50MW 8HR Storage (15yr Life)		
Year	Overnight Capital Cost ($/kW)	FOM ($/kW-yr)
2028	$2,950	$74
2029	$2,900	$72
2030	$2,846	$71
2031	$2,868	$72
2032	$2,890	$72
2033	$2,912	$73
2034	$2,932	$73
2035	$2,952	$74
2036	$2,971	$74
2037	$2,989	$75
2038	$3,007	$75
2039	$3,023	$76
2040	$3,038	$76
2041	$3,053	$76
2042	$3,066	$77
2043	$3,078	$77
2044	$3,088	$77
2045	$3,098	$77
2046	$3,105	$78
2047	$3,112	$78
2048	$3,117	$78
2049	$3,120	$78
2050	$3,121	$78

50MW 4HR VPP Storage (15yr Life)		
Year	Overnight Capital Cost ($/kW)	FOM ($/kW-yr)
2028	$3,344	$84
2029	$3,323	$83
2030	$3,308	$83
2031	$3,348	$84
2032	$3,388	$85
2033	$3,428	$86
2034	$3,468	$87
2035	$3,508	$88
2036	$3,548	$89
2037	$3,588	$90
2038	$3,627	$91
2039	$3,666	$92
2040	$3,705	$93
2041	$3,743	$94
2042	$3,781	$95
2043	$3,819	$95
2044	$3,856	$96
2045	$3,892	$97
2046	$3,928	$98
2047	$3,963	$99
2048	$3,998	$100
2049	$4,032	$101
2050	$4,065	$102

Table 2.11-22 Generic Costs for Nuclear AP100 and SMR

1000MW Nuclear AP1000 (60yr Life)				
Year	Overnight Capital Cost ($/kW)	Fuel Costs ($/MMBtu)	FOM ($/kW-yr)	VOM ($/MWh)
2034	$8,839	$0.98	$226	$3.67
2035	$9,004	$1.00	$232	$3.76
2036	$9,162	$1.03	$237	$3.86
2037	$9,323	$1.05	$243	$3.95
2038	$9,493	$1.08	$250	$4.05
2039	$9,654	$1.10	$256	$4.15
2040	$9,827	$1.13	$262	$4.26
2041	$10,010	$1.16	$269	$4.36
2042	$10,185	$1.19	$275	$4.47
2043	$10,372	$1.22	$282	$4.58
2044	$10,555	$1.25	$289	$4.70
2045	$10,736	$1.28	$297	$4.82
2046	$10,922	$1.31	$304	$4.94
2047	$11,114	$1.35	$312	$5.06
2048	$11,307	$1.38	$319	$5.19
2049	$11,495	$1.41	$327	$5.32
2050	$11,636	$1.45	$336	$5.45

300MW Nuclear SMR (60yr Life)				
Year	Overnight Capital Cost ($/kW)	Fuel Costs ($/MMBtu)	FOM ($/kW-yr)	VOM ($/MWh)
2034	$9,657	$0.98	$177	$4.65
2035	$9,836	$1.00	$181	$4.77
2036	$10,010	$1.03	$185	$4.89
2037	$10,186	$1.05	$190	$5.01
2038	$10,372	$1.08	$195	$5.13
2039	$10,548	$1.10	$200	$5.26
2040	$10,738	$1.13	$205	$5.39
2041	$10,939	$1.16	$210	$5.53
2042	$11,130	$1.19	$215	$5.67
2043	$11,334	$1.22	$220	$5.81
2044	$11,536	$1.25	$226	$5.95
2045	$11,734	$1.28	$232	$6.10
2046	$11,937	$1.31	$237	$6.25
2047	$12,148	$1.35	$243	$6.41
2048	$12,360	$1.38	$249	$6.57
2049	$12,565	$1.41	$256	$6.74
2050	$12,719	$1.45	$262	$6.90

Table 2.11-23 Generic Costs for Long Duration Energy Storage and Biomass

50MW Long Duration Energy Storage (20yr Life)			
Year	Overnight Capital Cost ($/kW)	10yr Capital Upgrade Cost ($/kW)	FOM ($/kW-yr)
2028	$2,327	$1,164	$18
2029	$2,363	$1,182	$19
2030	$2,400	$1,200	$19
2031	$2,435	$1,218	$19
2032	$2,471	$1,236	$20
2033	$2,508	$1,254	$20
2034	$2,545	$1,272	$21
2035	$2,582	$1,291	$21
2036	$2,620	$1,310	$22
2037	$2,659	$1,330	$23
2038	$2,698	$1,349	$23
2039	$2,738	$1,369	$24
2040	$2,778	$1,389	$24
2041	$2,819	$1,410	$25
2042	$2,861	$1,431	$26
2043	$2,903	$1,452	$26
2044	$2,946	$1,473	$27
2045	$2,989	$1,495	$28
2046	$3,034	$1,517	$28
2047	$3,078	$1,539	$29
2048	$3,124	$1,562	$30
2049	$3,170	$1,585	$30
2050	$3,217	$1,608	$31

50MW Biopower (30yr Life)				
Year	Overnight Capital Cost ($/kW)	Fuel Costs ($/MMBtu)	FOM ($/kW-yr)	VOM ($/MWh)
2028	$5,184	$6.71	$201	$6.46
2029	$5,281	$6.88	$206	$6.62
2030	$5,381	$7.05	$212	$6.78
2031	$5,472	$7.22	$217	$6.95
2032	$5,569	$7.40	$222	$7.13
2033	$5,673	$7.59	$228	$7.31
2034	$5,778	$7.78	$234	$7.49
2035	$5,885	$7.97	$239	$7.68
2036	$5,988	$8.17	$245	$7.87
2037	$6,094	$8.38	$252	$8.06
2038	$6,204	$8.59	$258	$8.27
2039	$6,310	$8.80	$264	$8.47
2040	$6,423	$9.02	$271	$8.68
2041	$6,543	$9.25	$278	$8.90
2042	$6,657	$9.48	$285	$9.12
2043	$6,779	$9.71	$292	$9.35
2044	$6,899	$9.96	$299	$9.59
2045	$7,017	$10.21	$307	$9.83
2046	$7,138	$10.46	$314	$10.07
2047	$7,264	$10.72	$322	$10.32
2048	$7,388	$10.99	$330	$10.58
2049	$7,511	$11.27	$338	$10.85
2050	$7,603	$11.55	$347	$11.12

Table 2.11-24 Generic Costs for Hydrogen Electrolyzer and Geothermal

50MW Electrolyzer (10yr Life)		
Year	Overnight Capital Cost ($/kW)	VOM ($/MMBtu)
2030	$5,578	$2.58
2031	$5,727	$2.64
2032	$5,876	$2.71
2033	$6,025	$2.78
2034	$6,174	$2.84
2035	$6,323	$2.92
2036	$6,472	$2.99
2037	$6,621	$3.06
2038	$6,770	$3.14
2039	$6,919	$3.22
2040	$7,067	$3.30
2041	$7,216	$3.38
2042	$7,365	$3.47
2043	$7,514	$3.55
2044	$7,663	$3.64
2045	$7,812	$3.73
2046	$7,961	$3.83
2047	$8,110	$3.92
2048	$8,259	$4.02
2049	$8,408	$4.12
2050	$8,556	$4.22

50MW Geothermal (30yr Life)		
Year	Overnight Capital Cost ($/kW)	FOM ($/kW-yr)
2030	$11,256	$372
2031	$11,171	$354
2032	$11,123	$336
2033	$11,105	$316
2034	$11,112	$295
2035	$11,139	$272
2036	$11,361	$279
2037	$11,587	$286
2038	$11,817	$293
2039	$12,052	$300
2040	$12,291	$308
2041	$12,535	$316
2042	$12,785	$323
2043	$13,039	$332
2044	$13,298	$340
2045	$13,562	$348
2046	$13,832	$357
2047	$14,107	$366
2048	$14,387	$375
2049	$14,673	$384
2050	$14,965	$394

~~Table 2.11-25 Annual Economic Carrying Charge of Dispatchable Generic Resources~~

Economic Carrying Charge ($/kw-mo)		
COD	Generic CT	Generic CC
2025	$11.95	$15.27
2026	$12.25	$15.65
2027	$12.55	$16.04
2028	$12.87	$16.44
2029	$13.19	$16.85
2030	$13.52	$17.27
2031	$13.85	$17.70
2032	$14.20	$18.15
2033	$14.55	$18.60
2034	$14.92	$19.06
2035	$15.29	$19.54
2036	$15.67	$20.03
2037	$16.06	$20.53
2038	$16.46	$21.04
2039	$16.87	$21.57
2040	$17.30	$22.10
2041	$17.73	$22.66
2042	$18.17	$23.22
2043	$18.62	$23.80
2044	$19.09	$24.40
2045	$19.57	$25.01
2046	$20.05	$25.63
2047	$20.56	$26.27
2048	$21.07	$26.93
2049	$21.59	$27.60
2050	$22.13	$28.29

Table 2.11-25 Levelized Cost by In-Service Year

Levelized Cost by In-Service Year($/kw-mo)		
COD	Generic CT	Generic CC
2025	$14.40	$17.74
2026	$14.76	$18.18
2027	$15.13	$18.63
2028	$15.50	$19.10
2029	$15.89	$19.58
2030	$16.29	$20.07
2031	$16.69	$20.57
2032	$17.11	$21.08
2033	$17.54	$21.61
2034	$17.98	$22.15
2035	$18.42	$22.70
2036	$18.88	$23.27
2037	$19.36	$23.85
2038	$19.84	$24.44
2039	$20.34	$25.05
2040	$20.84	$25.68
2041	$21.36	$26.32
2042	$21.90	$26.98
2043	$22.44	$27.65
2044	$23.00	$28.34
2045	$23.58	$29.05
2046	$24.17	$29.77
2047	$24.77	$30.52
2048	$25.39	$31.28
2049	$26.02	$32.06
2050	$26.67	$32.86

Table 2.11-26 Generic Costs for Wind and Solar

Levelized Costs by In-Service Year (30 year life)			
Year	**PTC**	**Wind**	**Solar**
2028	100%	$17.20	$24.40
2029	100%	$16.80	$23.40
2030	100%	$16.50	$22.30
2031	100%	$16.50	$21.10
2032	100%	$16.50	$19.90
2033	100%	$16.50	$18.60
2034	100%	$16.60	$17.20
2035	100%	$16.50	$15.70
2036	100%	$16.50	$15.50
2037	0%	$45.40	$42.00
2038	0%	$46.00	$42.40
2039	0%	$46.70	$42.90
2040	0%	$47.40	$43.30
2041	0%	$48.10	$43.70
2042	0%	$48.80	$44.10
2043	0%	$49.50	$44.50
2044	0%	$50.20	$44.80
2045	0%	$51.00	$45.20
2046	0%	$51.70	$45.60
2047	0%	$52.40	$45.90
2048	0%	$53.10	$46.30
2049	0%	$53.90	$46.60
2050	0%	$54.60	$46.90

2.12 WATER RESOURCES

In this Section, the Company provides water resources information required by Rule 3604(h), including: (1) the annual water consumption for each of Public Service's existing generation resources; (2) the water intensity (in gallons per MWh) of the existing generating system as a whole; and (3) the projected water consumption for any resources proposed to be owned by the utility and for any new generic resources included in the utility's modeling for its resource plan.

Use of Water in Electric Generation

Water is consumed during electric generation in a variety of ways:

1. Steam/water cycle. Steam generation is typically a closed-loop system, but boiler feed make-up water is required to replace minor losses.
2. Circulating water cooling. Circulating water is used to cool steam in the steam/water cycle. Circulating water is evaporatively cooled in the cooling towers and reused until its water quality is no longer suitable. Blowdown rejected from the cooling tower is treated prior to discharge or stored and evaporated, depending on plant design. Cooling typically represents the vast majority of plant water usage and consumption.
3. Other usage. Relatively small volumes of water are used in a number of other important plant capacities, such as dust suppression, fire control, bottom ash removal, and emissions control.
4. Hydro-electric generation. Water consumed is through evaporation while stored in reservoirs at Public Service-owned hydropower facilities in Colorado.

Public Service's Water Consumption and Intensity

Table 2.12-1 shows the 2023 water consumption as well as average use for the Public Service system.

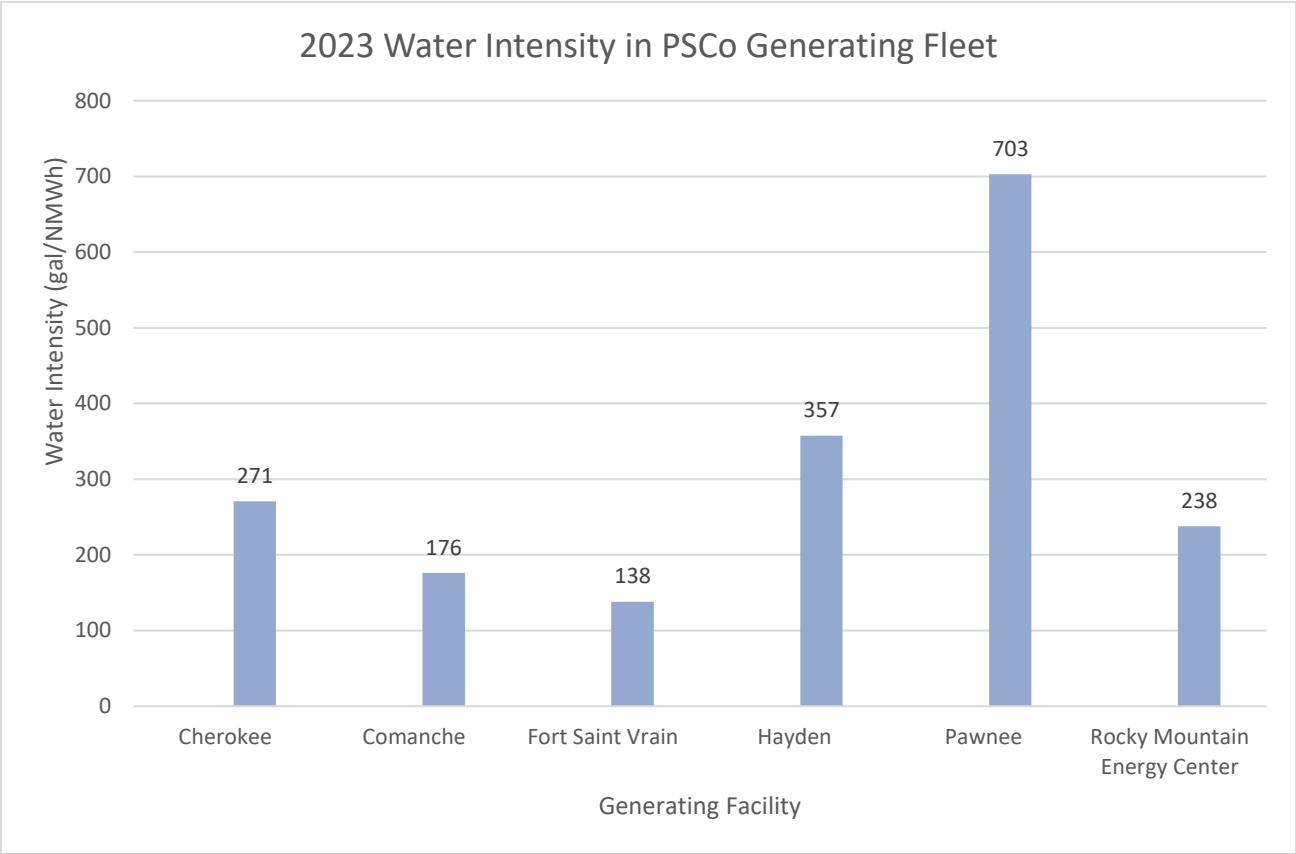
Figure 2.12-1 shows the water intensity for Public Service-owned generation stations. Generally, self-supplied water is the least expensive and future costs are expected to remain stable, in accordance with O&M needs. Contracted water supply costs are anticipated to increase in line with regional water costs but afford plants the reliability and firm yields associated with larger municipal water purveyors. Table 2.12-1 shows annual consumptive water use and intensity by Public Service facility.

Table 2.12-1 2023 Water Use and Generation by Public Service Facility

Public Service Generating Facility	2023 Consumptive Water Use (Acre-feet)	Percent Consumptive Water Use (%)	2023 Net Generation (MWh)	Water Intensity (gal/MWh)
Cherokee	2,956	100%	3,559,348	271
Comanche	6,505	80%	9,657,567	176
Fort Saint Vrain	2,110	82%	4,096,080	138
Hayden	3,988	100%	3,637,001	357
Pawnee	5,932	100%	2,750,537	703
Rocky Mountain Energy Center	1,706	100%	2,338,705	238
Valmont (1)	1,687	0%	31,697	N/A
Hydros(2)	98	100%	33,260	960
Craig (Xcel Portion)(3)	178	100%	23,226	2497
Alamosa(4)	0	N/A	7,775	N/A
Blue Spruce(4)	0	N/A	542,340	N/A
Ft. Lupton(4)	0	N/A	2,192	N/A
Fruita(4)	0	N/A	33,948	N/A
TOTAL	**25,160**		**26,713,676**	

(1) Raw water usage at Valmont is the amount of water attributed to diversions under the Valmont water rights.
(2) Hydro water consumption from reservoir evaporation. Hydro net generation includes Ames, Georgetown, Salida, Shoshone, and Tacoma, but excludes Cabin Creek.
(3) Xcel Energy owns 9.7% of Craig Units 1&2.
(4) Internal combustion engines and existing CT Turbine facilities require no water for generation using gas.

Figure 2.12-1 Water Intensity



2.13 PHASE II RESOURCE ACQUISITION PLAN

In this Section, the Company describes its Phase II resource acquisition plan, bidding policy, and the competitive acquisition procedures it intends to use to obtain resources in Phase II of the JTS process as required by Rule 3611(g). Volume 3 of the Company's 2024 JTS Phase I filing contains the proposed RFP the utility intends to use to solicit bids for energy and capacity resources to be acquired through the Phase II competitive acquisition process, the associated bid forms, and model purchase agreements, as required by Rule 3604(i) and Rule 3616(a).

Development of Phase II Scenarios

Phase II portfolios will be developed to simultaneously meet the reliability needs of the system, enable public policy goals, serve existing and new customers that desire to reside in our community, seek just transition benefits and allow space for future procurement of advanced technologies to help the Company progress towards a carbon-free future. To meet this end, as well as to provide the focused information the Commission and Stakeholders need to determine the Company's path forward in the RAP, the Company is proposing to advance the following portfolios in the Phase II final report.

Solution Set 1: 80% emissions reduction in 2030, declining to 0% in 2050

- 1A: Informational Least Cost plan
- 1B: Plan with 2021 ERP & CEP settlement provisions of $690M Company investment plus 50% of the remainder

Solution Set 2: 90% emissions reduction in 2033, declining to 0% in 2050

- 2A: Informational Least Cost plan
- 2B: Plan with 2021 ERP & CEP settlement provisions of $690M Company investment plus 50% of the remainder

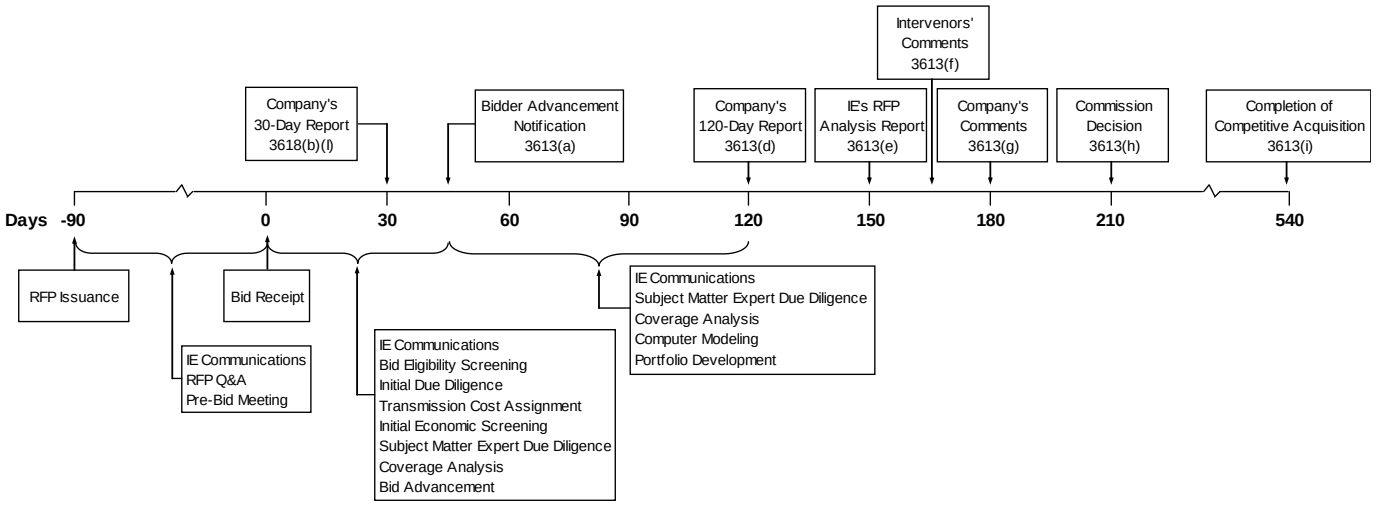
All portfolios will be run under both SCC and $0 CO2, creating eight total portfolios.

Company Activities Following the Release of the RFP

The Company anticipates initiating the competitive solicitation by issuing its Request for Proposal ("RFP") approximately 90 days in advance of the bid receipt date. As filed in Volume 3 of this 2024 JTS, the Company is introducing a unified RFP document, rather than multiple separate RFPs for dispatchable, renewable, and Company-owned resources as in previous solicitations. The RFP document along with the model PPA contracts or term sheets for Company ownership, technical specifications, and bid proposal forms will be posted to an RFP webpage on the Company's website (http://www.XcelEnergy.com) on the day of the RFP release. An indicative timeline of Phase II activities as prescribed by the ERP Rules is shown in Figure 2.13-1. The Company notes, however, that concurrent with its Phase I JTS filing, the Company has filed an Omnibus Motion that seeks a partial waiver of the deadlines set forth in Rule 3618(b)(I), Rule 3613(a), and Rule 3613(d) to extend the deadlines from 30, 45, and 120

days from bid receipt, respectively, to 45, 60, and 180 days from bid receipt, respectively, for the reasons discussed in the Motion.

Figure 2.13-1 Indicative Phase II Timeline as Prescribed by ERP Rules



Rule 3616(d) requires the Company to provide potential bidders with the Commission's orders specifying the form of nondisclosure agreement necessary to obtain access to confidential and highly confidential modeling inputs and assumptions provided by the Company pursuant to Rule 3613(b). This nondisclosure agreement is included in the RFP document and included as part of the Volume 3 filing. Rule 3616(d) also requires the Company to provide potential bidders with an explanation of the process by which disputes regarding inputs and assumptions to computer-based modeling will be addressed by the Commission pursuant to Rule 3613(b). This explanation can be found in Section 1.1 of the model RFP documents.

Rule 3616(e) directs the Company to require bidders to provide the contact information of a person designated to receive a notice pursuant to Rule 3613(a). Language directing the bidder to provide this information is on Form C of the model bid submission forms. Rule 3616(f) requires the Company to inform bidders that information for all bids submitted in response to the RFP will be made available to the public through posting of the bid information on the Company's website upon the completion of the competitive acquisition process pursuant to Rule 3613(k). This information can be found in Section 1.1 of the model RFP documents.

The Company anticipates that any pre-bid meeting will be held approximately three (3) weeks following the issuance of a competitive solicitation. In addition to a pre-bid meeting, the Company will directly respond to potential bidder questions submitted via email. Non-confidential Q&A versions of issues raised during any pre-bid meeting as well as from questions submitted via email will be posted to the Q&A document on an RFP webpage. The Independent Evaluator will be copied on all emails sent directly to potential bidders.

Bid Evaluation Fees

All respondents to the RFP are required to pay the Company a bid evaluation fee with each proposal submitted which is determined by the nameplate capacity of the bid according to Table 2.13-1 below. Public Service may deem proposals that do not satisfy the requirements for a single proposal as multiple proposals, each of which would require a separate bid evaluation fee. For example, a proposal that triggers electric interconnection studies for multiple points or levels of interconnection would be deemed separate proposals for each such point or level. Proposals offering multiple commercial operation dates, capacity sizes, commercial structures, or tenors for the same project or facility will be viewed as multiple proposals. Additionally, proposals to pair storage with a renewable resource bid will be viewed as a separate bid from a renewable only bid. All of these would also require a complete and separate bid package with separate bid forms for each optionality. If the Company deems a respondent's proposal to be multiple proposals, the Company will notify the respondent and allow it to elect to pay the incremental bid fee or to revise its proposal to comply with the Company's requirements for a single proposal. Bid fees are non-refundable.

Notwithstanding the above, there are specific circumstances where respondents may submit multiple proposals under one bid fee (but still a separate bid package with unique bid forms):

a. Bidders who wish to submit a project that proposes interconnecting to the May Valley-Longhorn Extension may also submit an alternative bid that interconnects elsewhere on the transmission system without paying a separate bid fee.
b. No additional bid fees are required when providing thermal bids with both on-site fuel storage and firm fuel delivery options for a single unique project.

Table 2.13-1 Bid Fees

MW Range	Bid Fee
>2 to 5 MW	$1,500
>5 to 10 MW	$3,000
>10 MW	$10,000

Any bidder(s) selected to begin negotiation of a PPA or Purchase & Sale Agreement shall also be required to submit a Second Bid Fee of $1/kW (e.g., 100 MW Project * $1/kW = $100,000) to the Company prior to commencement of negotiations. Upon execution of a PPA or Purchase & Sale Agreement the Second Bid Fee shall be refunded to the bidder. However, if the bidder and the Company fail to execute a PPA or Purchase & Sale Agreement due to, in whole or in part, bidder's actions that do not reflect bidder's representations or commitments during the RFP bidding process, the Company shall have the right to retain the Second Bid Fee.

Bid Receipt and Generation Technology Categorization

The Company will request only electronic versions of proposals; copies of bid submission materials will be provided to the Independent Evaluator and to Commission Staff. Upon receipt of bids, the Company will conduct an initial review to categorize the bid by its proposed generation source with bids employing similar technologies. Such an initial categorization simplifies downstream due diligence and economic evaluations and is necessary to comply with ERP Rule 3618(b)(I) regarding bidder notification.

Bid Eligibility Screening and Initial Due Diligence

Once bids have been cataloged, the Company will conduct a review of each bid to ensure that the proposal meets the minimum eligibility requirements. There are slightly different minimum eligibility requirements corresponding to the different generation technologies or ownership structures; specific details on the minimum bid eligibility requirements are laid out in the RFP document in Volume 3. The Company intends to notify all RFP

respondents on or before the deadline established by the Commission as to the Company's bid eligibility evaluation.

At the time that the Company conducts its bid eligibility screening, it will also conduct an initial due diligence review of the bids. This initial due diligence review is intended to quickly identify any potential fatal flaws or conceptual misunderstandings as to the proposed project. To the extent the Company requires additional information from the bidder as a result of its initial due diligence, it will contact the bidder promptly and ensure that the Independent Evaluator receives a copy of the request for additional information as well as a copy of the bidder's reply.

Conforming Bid Policy

In support of the Company's efforts to complete project evaluation and contract negotiations in a timely manner, as well as to ensure projects are compared on a like-for-like basis, the Company is proposing that RFP respondents shall provide pricing that is consistent and compliant with the Model PPA or Model Term Sheet for the proposed resource type. The Company would require every Bidder to provide a proposal and associated firm non-conditional bid price that is fully compliant with PSCo's model agreements without markup or exceptions and not subject to adjustment in the future.

The definition of exceptions includes redline edits as well as any indication, inference, notes, remarks, statements, assumptions, or expectation that such may/will be negotiated following a selection of the bid submitted. The Company would expect that each Bidder consider and commit to all development and performance risks, costs, and obligations as represented in the model agreement before bidding and not condition the proposal with such risks, costs or obligations being shifted to PSCo or its customers. For avoidance of doubt, these include but are not limited to, costs or delays related to supply chain disruption, construction, interconnection, permitting, market changes, or changes in law. Should a proposal be selected, the Bidder would certify that: (i) their bid price reflects the terms of the model agreement in its entirety (aside from bracketed and/or facility-specific details), (ii) Bidder can meet all obligations under the model agreement, and (iii) Bidder understands and accepts all associated risk therein. The Company would not enter into an agreement that is conditioned on the Seller's ability to source and deliver equipment, qualify for tax benefits, or secure permits and would not entertain exit clauses or rate adjustment clauses.

The model PPA as drafted and litigated in Phase I of this proceeding would be approached as a minimum set of terms for purposes of bidding into the RFP. The follow-on negotiation process would allow for immaterial changes and edits to accommodate each project's unique characteristics as well as mutually agreeable changes to add clarity, correct errors, and update terminology or definitions. Additionally, the Company commits to good faith negotiations to accommodate material changes as well, so long as the change does not materially shift risk to the customer or undermine the bid assumptions under which the project was selected.

For clarity, the terms listed below as outlined in the model agreement, and to litigated in Phase I, are considered by the Company to materially impact reliability and resource adequacy, as well as cost and/or risk to the customer and should be considered as non-negotiable in their entirety.

- Performance Requirements
- Permitting
- Environmental and Construction
- Tax Qualification
- Supply Chain
- Senate Bill 23-292 and Forced Labor
- Changes in Law
- Security Requirements
- Defaults, Damages and Remedies
- Payment Mechanisms
- Transfer Limitations
- Construction and Development Milestones
- Force Majeure

Location-Based Generation Considerations

For the JTS RFP three location-based considerations for bids aim to (1) prioritize just transition benefits, (2) address transmission system constraints, and (3) prevent further system operations challenges. The transmission evaluation adder, transmission evaluation credit, and Pueblo solar regulating reserve adder are proxy costs that intend to represent the future real-world costs of transmission in the Phase II modeling process. As such, they should not be misconstrued as reflections of true bid costs.

Just Transition

The RFP will prioritize resources that include just transition benefits in Pueblo and Routt Counties, which were affected by the Coal Action Plan approved in the 2021 ERP and CEP (i.e., the retirement of Comanche 3 in 2031, Hayden 1 in 2028, and Hayden 2 in 2027). The Company will prioritize just transition benefits by adding a price credit (bonus) to projects located within Pueblo or Routt Counties. This price credit will have a base value that is achieved for being located within Pueblo or Routt Counties, and then two bonuses that can be added to the base value, similar to the Production Tax Credit (“PTC”) and Investment Tax Credit (“ITC”) in the Inflation Reduction Act (“IRA”).

The values for the credit are shown in Table 2.13-2 below. The credits differ for capacity-type resources (e.g., firm dispatchable, standalone storage, aggregated DERs) and weather-dependent, energy-based resources (e.g., wind and solar). Resources that provide both benefits (e.g., hybrid renewable projects, geothermal, biomass) would have both credits applied.

Table 2.13-2 Just Transition Bonus Credits

	Capacity Resource Credit ($/kW-Month)	Energy Resource Credit ($/MWh)
Base: Located within target communities	**$1.00**	**$2.00**
Bonus: Creates > 20 Long Term Jobs	**$0.50**	**$1.00**
Bonus: Provides > $4 Million in Annual Property Taxes	**$0.50**	**$1.00**
Potential Total Credit	**$2.00**	**$4.00**

In addition, we will also include the offset property tax benefit, based on the projected property taxes information supplied by the bidders, consistent with the methodology used in the 2021 ERP/CEP for projects in Pueblo or Routt Counties.

Transmission Constraints

The transmission analysis conducted in the 2021 ERP identified a significant generation import limitation into the Company's primary load center, which is now commonly termed the "Denver metro constraint."

The Denver metro constraint refers to transmission limitations that constrain the amount of electricity that is able to be brought into the Denver metro load center from outside of the metropolitan area. More specifically, for purposes of the Phase I generic modeling, resources whose electricity flows into the metro area through main substations south and east of Denver (i.e., Daniels Park, Smoky Hill, and Harvest Mile) are subject to the constraint. Existing resources that are already located within the load center, or that connect to the load center through western or northern substations (i.e., Lookout, Hogback, Ft. St Vrain, Rocky Mountain Energy Center, etc.) are considered within the constraint and not subject to its limitation. This constraint is currently modeled in EnCompass as a limit of 3,800 MW in 2028 that gradually increases to 5,000 MW in 2031.

For this RFP, the Company plans to use the results of the JTS Transmission Study to inform bid evaluation in two ways. First, all resources, except ADER or other distribution connected resources, will have an "evaluation transmission adder" included to represent a proxy cost of network upgrades related to network delivery for incremental resources. To represent the benefits of delayed or avoided transmission costs for resources constructed within the Denver metro constraint, an "evaluation transmission credit" will be afforded to bids that are either beneficial or neutral to congestion on the constraint. The Company would apply these costs/credits as appropriate to bids based on bid location.

The specific values for these factors have been calculated from inferring transmission costs and impacts from the Base Load portion of the JTS Transmission study using the applicability of the various mitigations seen in the study itself,[16] and the indicative cost

[16] See Attachment AWS-1 to the Direct Testimony of Company Witness Mr. Andrew Siebenaler.

estimates contained in the Direct Testimony of Company witness Mr. Andrew Siebenaler. As the May Valley-Longhorn Extension need and costs are proposed to be evaluated in the Phase II modeling directly, using the same methodology as in the 2021 ERP & CEP, those costs are excluded from this analysis.

The evaluation transmission adder for all resources is obtained by taking the average cost of all portfolios divided by the average MWs added (exclusive of ADER) in all portfolios. The evaluation transmission credit is obtained by comparing the results for the Bookend 2 and Baseline portfolios. The delta in costs (exclusive of MVLE) for these portfolios is divided by the amount of incremental non-constraint impacting generation (i.e. ADER) in those portfolios to determine a representative $/kW delayed or avoided transmission cost benefit. This credit, in conjunction with the modeled transmission topology and associated congestion, provide two methodologies that will advantage bids within the Denver metro constraint. The calculations and values for the transmission adder and credit are shown below in Table 2.13-3. These costs would be applied to the bid using a 10% levelized fixed charge rate ("LFCR").

Table 2.13-3 Transmission Adder and Credit

All Bids/Resources Transmission Adder		
Avg Trx Capital Cost (no MVLE) ($)	$	2,106,000,000
Avg Portfolio (less ADER) (kW)		8,850,000
Base Transmission Adder ($/kW)	**$**	**237.97**
Denver Metro Constraint Transmission Credit		
Bookend 2 vs. Baseline		
Delta Cost	$	415,000,000
Remove Segment 6 MVLE	$	(272,000,000)
	$	143,000,000
Delta ADER (kW)		750,000
Credit for Inside Metro Constraint ($/kW)	**$**	**190.67**

For bid evaluation purposes, it is necessary to have a clear signal to bidders of what is and is not beneficial from a locational perspective. That analysis is complex and will evolve over the course of the proceeding based on further analysis, intervenor feedback, and Commission direction, with completion prior to RFP issuance to allow for inclusion in the RFP and bidder evaluation of the adder/credit. Additionally, if further analysis informs the modeling topology setup and associated flow limits, that information will be supplemented as well.

System Operational Challenges

Lastly, for the system operations challenge, there are currently 1,133 MW of solar generation resources in and around Pueblo, with another 1,460 MW of projected solar being added through the 2021 ERP & CEP approved Alternative Portfolio. Because of the significant concentration of solar resources in this area, local weather events, such as regular afternoon thunderstorms in the summer, can cause rapid down and up ramps of

more than 1,000 MW of solar generation currently, and likely larger as the new resources come online, in very short time periods (e.g., 10 minutes). These ramps pose significant challenges to our system operators.

To prevent this specific issue from worsening, and to encourage geographic diversity of solar resources, solar resources in Pueblo County will not be modeled with the Just Transition Benefit Credit discussed above. Additionally, the Company's Commercial Operations team conducted a study on the expected regulation reserve requirement associated with incremental solar generation in the Pueblo area, which is included as Attachment JTL-2, the Solar Regulating Reserves Study, to the Direct Testimony of Company witness Mr. Jon T. Landrum. The results of this study indicated that the incremental costs are approximately $7.68/kW-year and this cost adder will be added to all solar bids in the Pueblo area, which is defined for this purpose as being within a 37-mile radius of 38.218° latitude, -104.474° longitude.

Bid Evaluation Process

Assignment of Transmission Interconnection and Bid-Specific Network Upgrade Costs

The Company anticipates that it will declare each proposal selected through the RFP as a Network Resource of the Company, i.e., capacity and energy from the proposed generation project must be delivered to the Company's electric transmission or distribution system at a location such that the capacity and energy can then be delivered to the Company's customers. The Company will determine or verify electric interconnection cost and network delivery cost estimates provided by bidders. If substantial differences occur, the Company will provide its cost estimates to the applicable bidders so that they can update their bid pricing, as they deem appropriate. Such bidders must submit final bid pricing back to the Company within five (5) calendar days of the date the interconnection cost estimates are provided. Transmission-associated capital costs will be converted to annual levelized costs utilizing a levelized fixed charge rate ("LFCR") of 10% for inclusion in the initial economic screening.

Note, this typically only applies to POI costs and new switching stations, which are easily identifiable to specific bids. Generally, system network upgrades such as new lines and upgrading existing facilities are more relevant on a portfolio basis, with specific non-POI related network upgrades attributable to a single bid being rare. In the event a certain bid does fall into that category though, including through the completion of a previous LGIA study, the specific costs for that bid will be used in lieu of the general transmission credits and adders described above. In the event a specific bid requires upgrades identified through the SME review process, such and a new switching station or POI facilities those costs will be evaluated in conjunction with adders and credits above to ensure that all additive costs are included to the bid and no duplicative costs.

As an illustrative example, a bid that requires POI facilities and a new line tap/switching station, but no other identified specific network upgrades would have the POI and switching station costs applied as well as the $238/kW general cost adder. If it was

located in a beneficial location, it would also have the $191/kW credit applied, all at a 10% LFCR.

If the Company has received a CPCN to construct a transmission upgrade, the cost of the upgrade will not be included in the evaluation and costing of bids and/or bid portfolios that use those upgrades; provided, however, that sufficient transmission transfer capability exists on the transmission project specified in the CPCN after accounting for other generation projects.

For bids that: (1) utilize a transmission project for which a CPCN has been filed and is pending, or (2) utilize a Commission approved "bid-eligible planned transmission project" identified in the Phase I decision, transmission upgrade costs will not be included in the bids for purposes of determining advancement to computer-based modeling. In computer-based modeling, transmission upgrade costs will be included in the costing of the bids. At the completion of computer-based modeling, the total cost of the transmission upgrade will be included in any portfolio with a bid or bids that would utilize that transmission upgrade for portfolio costing and comparison purposes.

Existing resources from which the Company currently purchases capacity and energy will not be burdened with any incremental electrical transmission interconnection or network delivery costs provided that the Company currently has sufficient transmission capacity to deliver the entire generation to its load. For existing resources with inadequate transmission service, a projection of the purchase of sufficient transmission rights will be added to the bid.

Initial Economic Screening

Initial economic screening consists of calculating a levelized energy cost ("LEC") for energy-based bids (e.g., renewable or renewable hybrid generators) or, for dispatchable and standalone storage projects, a levelized cost of capacity ("LCC"). LECs are calculated as the present value of the sum of the total costs for each year of the proposed project's term divided by the present value of the estimated annual energy streams. LCCs are calculated similarly, but the divisor is the capacity, not energy. Present values are calculated as of the project's in-service year to avoid confusing the inherent value of delay with true differences in the levelized cost. The Company will employ its after-tax WACC in the present value calculations. The primary purpose of the initial economic screening is to rank each bid by technology so that the most promising bids can be forwarded to the subject matter experts for their review as quickly as possible and to identify those bids likely to be moved forward for computer modeling of bid portfolios.

In addition to the costs provided in the bid, the Company will estimate incremental costs or benefits, as necessary, such as:

- The Company's estimates of any incremental transmission interconnection or network upgrade costs not included in the bid's pricing.
- The Company's final natural gas forecast.

- The Company's estimates of fuel delivery costs on both an interruptible and a firm basis, where applicable.
- Projects that propose to interconnect to Public Service's distribution system will be credited with an avoided line loss assumption.
- Estimates of the Company's cost to deliver fuel (e.g., natural gas) to a tolled facility.
- Adjustments to estimated performance or pricing that result from the Company's due diligence efforts or updated information received from the bidder.
- Location benefits/costs in accordance with the narrative above
    - Just Transition
    - Pueblo Area Solar
    - Transmission Adder
    - Locational Transmission Credit (if applicable)

Outside of these general assumptions, specific costs and benefits will be calculated for bids employing certain generation technologies as detailed below.

Stand-Alone Storage PPA LCC

In addition to the capacity payment rates, LCCs for stand-alone storage bids include an annual representation of proposed variable costs. Variable payment rates will be converted to a $/kW-mo metric by applying the annual throughput limit (MWh) proposed for the storage device and then summed with all the fixed costs. The LCC is calculated by dividing the total costs by the ELCC-applied accredited capacity assigned to the project.

Dispatchable Generation PPA LCC

In addition to proposed capacity payment rates, LCCs for non-storage, dispatchable generation bids include an annual representation of proposed tolling payment costs and start charges. Tolling payments are calculated by converting the variable costs to fixed costs assuming an annual capacity factor and assuming an average annual heat rate with which to estimate fuel volumes and costs. Gas-fired, peaking resources (defined as units with base capacity heat rates over 8,000 Btu/kWh) will be screened with an assumption of a 5% annual capacity factor. Gas-fired, intermediate resources (defined as units with base capacity heat rates of 8,000 Btu/kWh or lower) will be screened with an assumption of a 20% annual capacity factor. The average annual heat rate utilized in the LCC calculations will be the base capacity heat rates (without supplemental capacity) supplied by the bidder.

Start charges for dispatchable generation resources are converted to a fixed cost by assuming a set number of hours that a unit will run at full output once started; full output is defined as the net capability of the unit without supplemental capacity (e.g., duct firing on a combined-cycle power plant). For peaking resources, the Company assumes a two (2) hour run time per unit. For intermediate resources, the Company assumes an eight (8) hour run time per unit and that all combustion turbines are started.

To the extent a project proposes to wheel capacity and energy across another utility's transmission system prior to delivery to the Company's system, estimated wheeling losses will be imposed against the full load heat rate which will effectively increase the variable cost component of the LCC. Such an adjustment is necessary since the heat rates are calculated at the generation unit (which resides on another utility's system), whereas the other components of the LCC are all based on capacity and energy delivered to the Company's system.

Renewable Hybrid Storage PPA LEC

An LEC for a renewable hybrid storage bid will be calculated in a similar manner as that for a standalone solar or wind facility using the present value of the sum of costs for each year of the proposed project's term divided by the present value of the estimated annual energy streams. Variable costs are calculated using the energy rate and annual committed energy and are combined with the fixed costs of the battery capacity payment rate multiplied by the nameplate capacity of the battery.

However, differences in battery sizing and duration make direct comparison of traditional LEC's for various hybrid projects ineffective at discerning cost/value relationships. The Company will use an adjusted LEC mechanism for hybrids that is calculated by first determining the capacity value of the storage resource by multiplying the surplus capacity credit value by the ELCC-adjusted firm capacity of the storage component of the bid on an annual basis. This capacity value will be deducted from the notional costs of the bid on a year-by-year basis, and an adjusted LEC will be calculated on the remaining costs divided by the energy supplied, on a net present value basis. This adjusted LEC will only be used in comparing and ranking hybrid bids of similar natures amongst themselves, and not comingled with standard LEC types of bids.

Company Ownership Bids

Calculating the LCC or LEC for Company ownership bids will be done in a similar manner as described above, but in lieu of PPA payment terms, an annual revenue requirement will be calculated using a standard pro-forma template that includes the capital cost and spend curve along with all of the financial estimates for ongoing capital and OM provided by the Company's SME's that are part of the technical due diligence team. Dispatch assumptions and any locational benefits/costs will be applied in the same manner as for PPAs.

Regardless of proposals' LEC and LCC calculations, consistent with Commission-approved practice in the past several ERPs, all eligible bids from existing generators, all Company self-build projects, and any bid claiming Section 123 status that is unopposed by the Company or, if opposed by the Company but later qualified as Section 123 by the Commission, will be advanced to computer modeling of bid portfolios.

Subject Matter Expert Due Diligence

Subject matter experts typically include, but are not limited to, Company personnel from the following organizations:

- Transmission Access
- Distribution Access
- Generation Resource Planning
- Transmission Planning
- Natural Gas Planning
- Commercial Operations
- Purchased Power
- Credit/Risk
- Tax
- Accounting
- Environmental Permitting
- Energy Supply
- Siting and Land Rights
- Water Supply

Each department conducts its due diligence reviews in the manner they determine best. In the event that subject matter experts require additional information or clarification on certain aspects of a bid, those requests will be forwarded to the bidders on a coordinated basis. Each bid reviewed by each department will result in a written due diligence report with an indication as to the feasibility of the project's ability to meets its proposed in-service date with the selected technology and proposed performance levels.

The Company reserves the right to employ outside technical experts to review bids to the extent the Company believes such analyses are warranted to sufficiently review any proposal.

Depending on the size and complexity of the bid pool, final due diligence determinations may not be completed on all bids at the 45-day mark. Bidders will be advanced on the presumption of clearing due diligence if it has not been completed for that bid. However, due diligence will continue until completed, and this may result in some bidders initially being advanced and later having fatal flaws identified. As with all fatal flaws, bidders will be afforded the opportunity to cure and all final decisions will be done in full cooperation with the IE, however this may result in some bids being rejected after initially being notified of advancement. Bidders will be notified of this determination in a timely manner.

Non-Price Factor Analysis

In its Phase II ARRR Decision (C24-0161), the Commission directed the Company to propose a transparent non-price factor bid evaluation process as part of its Phase I filing in the 2024 JTS. In the RFP and in Direct Testimony we state the criteria that bids will be evaluated on and the resulting specific actions that will be taken. In summary, consistent with past practices, due diligence teams would evaluate the bid proposal's section relevant to their expertise and score each bid as pass/fail. The evaluation would determine whether bids are eligible to be advanced to computer modeling or included in a final portfolio, depending on when the pass/fail determination is made. Only bids with uncurable fatal flaws or that don't meet the requirements of the RFP will be failed. The ultimate decision to reject a bid would be made by the RFP Manager with concurrence from the IE, and only after bidders have been given the opportunity to cure any deficiencies. The Company believes this more inclusive approach and erring on letting bids compete on their merits, rather than employing an arbitrary quantitative scoring rubric to make a cut line, makes more sense and creates more fair competition. Additionally, from a practical matter, if the bid submissions are similar to the 2021 ERP with over 1,000 bids being submitted, any rubric would have to be extremely simplistic to score bids in time to make advance to computer modeling decisions within 45 days of bid receipt, to the point where the Company believes it would be more discriminatory than effective. In summary, the Company believes the current approach, with the added clarifications on implementation and oversight, is the best method to use in Phase II.

Bid Summary Report (ERP Rule 3618(b)(I))

Pursuant to ERP Rule 3618(b)(I),[17] following bid receipt, the Company will report to the Commission the following topics:

- Bidder identity,
- Number of bids received (total and by resource type),
- MW (total and by resource type),
- Description of prices (by resource type),
- Whether or not the Company believes it needs to implement its contingency plan.

Secondary Economic Screening

Any adjustments to bid information that impacts a bid's LEC or LCC following the completion of the subject matter experts' due diligence efforts will be incorporated into final levelized calculations.

[17] Rule 3618(b)(I) requires the Company to report this information to the Commission within 30 days after bids are received in response to the RFP. In its Omnibus Motion filed in this proceeding, the Company is seeking a partial waiver of Rule 3618(b)(I) to file the required report 45 days after bid receipt for the reasons discussed in the Motion.

Computer Modeling

Selection of Bids for Computer Modeling

All bids from existing thermal generation resources currently under contract with the Company and all Company proposals will be passed through screening to portfolio development. Contingent upon the existence of sufficient bids passing through bid eligibility and due diligence screening, the Company shall pass forward to the portfolio development phase a sufficient quantity of bids across the various generation resource types such that resource plans can be created that conform to the range of scenarios for assessing the costs and benefits from the potential acquisition of increasing amounts of renewable energy resources or Section 123 Resources as specified in the Commission's Phase I decision.

To do this the Company will rank the bids by LEC/LCC grouped by technology type and ownership structure. The Company and the IE will jointly review the sorted list and determine a cutline (for each type/structure independently) with the goal being to advance enough bids, and the most economic bids, that would be able to create a portfolio consisting solely of that technology and ownership structure. This may result in a large number of bids advancing to computer modeling, but the Company believes it is better to err on the side of inclusivity at this initial review stage rather than risk artificially limiting options for portfolio development. Bidders whose projects are passed forward to portfolio development will be notified of their project's advancement pursuant to ERP Rule 3613(a) and will be provided with the modeling inputs and assumptions for that project pursuant to ERP Rule 3613(b).

To the extent initial EnCompass modeling indicates that all bids of a specific generation resource type (e.g., all wind bids) passed to portfolio development appear in the least-cost portfolio(s), additional bids utilizing that generation resource type will be included in subsequent model runs and bidders will be notified of their late advancement. This iterative process will be followed until model runs indicate that bids of that technology type were available to the model, but not selected.

Best-in-Class Modeling

If there are a large number of bids advanced to computer modeling, the Company will use the best-in-class process for reducing the number of bids through computer modeling techniques "in its toolbox" to be applied as needed, as is likely if the bid pool is similar in magnitude to the 2021 ERP. This process was detailed thoroughly in the 2023 120-Day Report from the last ERP. In the case of a large number of bids advanced to computer modeling, EnCompass will be used to determine a "first cut" to reduce the number of bids advancing to further rounds of computer-based modeling. We will evaluate each technology class (wind, solar, storage, hybrid, thermal, etc.) separately by utilizing the partial unit optimization feature of EnCompass to solve for the least-cost portfolio comprised solely of that technology class. Projects will be selected to be advanced further by this initial computer modeling process, or "best in class" approach, by determining if

any partial amount of a unit was picked by the model as part of a least-cost solution. The selected bids in the modeling will be included in the final bid list used for the development of the final portfolios. In the event multiple versions of the exact same project are selected, only the highest-ranking version will be moved forward. This process will be repeated multiple times if needed, until a robust set of bids for each technology are included. The IE will monitor the process and decision making for which bids advance further.

Bids for Generation between 100 kW and 10 MW[18]

In general, the following process will be employed to determine cost-effective bid-eligible proposals less than 10 MW:

1. Categorize bids by technology,
2. Categorize bids by size: greater than or equal to 10 MW and less than 10 MW,
3. Sort less than 10 MW bids by LEC and LCC,
4. Review the least-cost portfolio determined by EnCompass from the Base Case run and determine the generation types selected in each portfolio,
5. For each included generation type, determine all bid-eligible proposals less than 10 MW that have an LEC or LCC less than the highest LEC or LCC, respectively, for that generation type in the portfolio and include those projects in the final portfolios.

For example, assume that the most expensive solar bid included in a final portfolio has a $30/MWh LEC and, that solar bids less than 10 MW with the LEC shown in Table 2.13-4 below were proposed.

Table 2.13-4 Illustrative LEC for Eligible Solar Bids Less Than 10 MW

Bid #	LEC ($/MWh)	Size (MW)
1	$25	3
2	$22	1
3	$39	5
4	$32	5
5	$25	7

In this instance, the Company would include Bid numbers 1, 2, and 5 (totaling 11 MW) in the portfolios along with those proposals selected by EnCompass.

To the extent the least-cost portfolio does not include a certain generation type (e.g., solar) but lower priced bids (based on all-in LEC or LCC) than the lowest cost not-selected bid of that type exist for similar generators less than 10 MW, an ad hoc EnCompass run including those generators would be conducted to see if the revenue requirements of the

[18] Depending upon the pool of proposed projects received in a Phase II competitive acquisition, the Company may need to adjust the specific MW cutoff for various technologies instead of the 10 MW proposed here. Such an adjustment would be done in consultation with the Independent Evaluator.

least-cost portfolio increases or decreases. If the revenue requirements decrease with the addition of the less than 10 MW generators, they will be included in the final portfolios.

For certain generation types (e.g., hydro or gas-fired micro-turbines) the Company would not typically expect to receive bids in excess of 10 MW. For such situations, the lowest LEC or LCC proposals (up to a maximum of three per technology) would be advanced to computer modeling and portfolio development along with those bids greater than 10 MW already selected. To the extent the EnCompass model selected all three of the lowest LEC proposals and other proposals for the same technology were also received, then ad hoc EnCompass runs would be conducted to determine the cost-effectiveness of these other proposals.

Rule 3604(n) requires the Company to describe how energy storage systems smaller than 30 MW may be accommodated in the Phase II competitive solicitation process. The Company will evaluate energy storage project bids 10 MW and larger along with all other bids 10 MW and larger. Storage projects less than 10 MW will be evaluated according to the process described above.

Email Notification to Advanced Bidders

Pursuant to ERP Rule 3613(a),[19] after bids are received the Company is to email each bidder and indicate whether its bid has been advanced to computer modeling and portfolio development. For those bids not advanced, the Company is to provide the reason(s) why the project will not be evaluated further. For those bids advanced to computer modeling and portfolio development, the Company is to provide the modeling inputs and assumptions that reasonably relate to that potential resource or to the transmission of electricity from that facility to the Company.

The Company will meet these reporting procedures for proposals that are 10 MW and greater. However, given that proposals less than 10 MW will, in general, not be advanced to computer modeling and portfolio development during the initial phases of portfolio development, these proposals will not receive such notification at the 45-day mark. To the extent that proposals less than 10 MW are included in final portfolios after they have been created, bidders will be notified at that time.

Computer Modeling and Portfolio Development

EnCompass will be used to develop portfolios of bids that have been advanced to this stage of the competitive acquisition. The modeling framework Public Service will employ in the Phase II portfolio analysis is similar to that used to develop generic portfolios with two exceptions: (1) actual bids are used to meet RAP needs instead of generic estimates,

[19] Rule 3613(a) requires the Company to notify bidders of advancement to computer-based modeling within 45 days of the Company's receipt of bids. In its Omnibus Motion filed in this proceeding, the Company is seeking a partial waiver of Rule 3613(a) to notify bidders within 60 days after bid receipt for the reasons discussed in the Motion.

and (2) bids will be extended through the end of the modeling period to ensure the RAP portfolio firm capacity meets the PRM obligation through the end of the planning period and is not rejected by the model.

Bid Modeling

For the 2024 JTS, the Company will model all bids in all portfolios using the "Replacement Chain" methodology used in the 2021 ERP.

In this method, to extend bids that do not extend to the end of the modeling period, the bid will be sequentially "repeated" as many times as is necessary, keeping all parameters of the bid equivalent from both a financial and operational perspective. For operational characteristics, the exact same specifications of the bid[20] will be repeated using the same pattern (if it varies by year) as the original bid. As an example, for a sample 15-year bid, year 16 will have the specifications of year 1, year 17 will have year 2, etc.

All financial parameters, such as fixed or variable PPA payments, will be repeated so as to be financially equivalent to the bid proposal's costs throughout its term. In practice, the bid costs that are supplied in nominal dollars will first be converted to levelized equivalent fixed or variable costs using the Company's WACC. Then the levelized value will be escalated using the assumption for general inflation to the start of the repeat period and applied for the same number of years as the bid term. If a second "repeat" period is then needed (i.e., two times the bid term still does not extend through the modeling period), a third (or however many are necessary) repeat will be constructed in the same manner.

Company proposals will include the same costs and benefits as those applied in the initial economic screening of bids described earlier in this section. Company proposals and BOTs will be modeled using traditional capital revenue requirements when reporting annual total system costs. Since the useful lives of Company self-build proposals typically will extend through the end of the Planning period, generally no assumptions need be made on how to extend the lives of Company proposals. However, in the event a Company proposal does need to be backfilled, it will be done in the same manner as the bids. Just as with PPAs, the actual annual costs of the bid will be used for the bid period, and any extension will use the levelized cost escalated to the repeat year(s).

This extension process for bids is not in any way intended to represent "re-contracting" or any specific assumption regarding what resources will be chosen in the future years after the bid expires or what prices they will be offered at. It is simply a standard financial analysis methodology used to evaluate competing projects/proposals with unequal lives. In financial literature, it is often referred to as the "replacement chain" approach. Ideally, this approach would have enough replacements made to evaluate all the projects on a least common multiple of years (for example a 20-year bid and a 25-year bid would be evaluated over a 100-year period with 5 and 4 repetitions, respectively). However, this is

[20] Such as capacity factor, nameplate capacity and generation profile for renewable bids, and heat rate and forced outage rate for dispatchable bids.

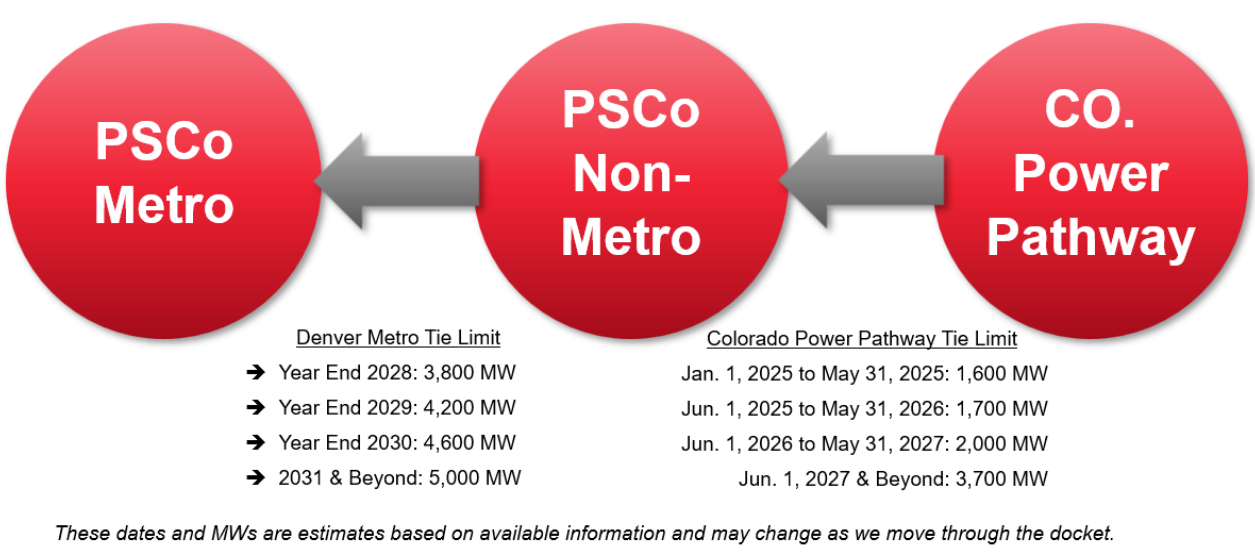
not practical in computer modeling given the possibility of widely disparate lives leading to extremely long study periods (as in the given example in the previous sentence), nor is it consistent with Commission resource planning rules which require that NPV be calculated over a Planning Period of determinate length. Additionally, given that the economics of the portfolios are primarily evaluated on the basis of NPV, impacts beyond the modeling period have only small impacts due to the time value of money/discount rate, and there is little precision lost by cutting off all values past the modeling period.

Modeling Topology

The transmission analysis conducted in the 2021 ERP identified a significant generation import limitation into the Company's primary load center that has now been commonly termed the Denver Metro Constraint. Although that analysis is in the process of being updated and acted upon, both during the construction period of any approved projects, and possibly even beyond, this limitation will remain important in integrated system planning. As an improvement to the 2021 ERP EnCompass modeling, this constraint is being incorporated into the resource planning modeling process on the "front end" in two ways: first by modeling the physical system limitations, and second by including the avoided/incremental network upgrade costs to connect the resource. These costs have been described above, while this section details the topology implementation in greater detail.

For the Phase I modeling, we have addressed transmission system constraints by adding a simplified transmission system topology layer to the EnCompass model. This topology layer will essentially group resources into three main regions: metro resources, non-metro resources, and Colorado's Power Pathway ("CPP") resources. Each region has specific transfer limitations, varying by year, to neighboring regions that are informed by the best available current transmission studies and are shown in Figure 2.13-2 below.

Figure 2.13-2 EnCompass Transmission Topology



The same CPP simultaneous injection limit used in the 2021 ERP is being used for Phase I of the JTS and exists between the CPP and non-metro regions in the model. The model then ties the non-metro region to the metro region via the Denver metro constraint tie. This represents the major transmission limitations for all electricity being brought into the Denver metro from surrounding areas in a simplified manner. As the model solves for the most economical solution, including the minimization of curtailments and avoidance of congestion, the model will naturally seek to prioritize resources within the Denver metro constraint, subject to economics. This topology is expected to be the same in the Phase II modeling, pending further study that might provide better information regarding topology or flow limits.

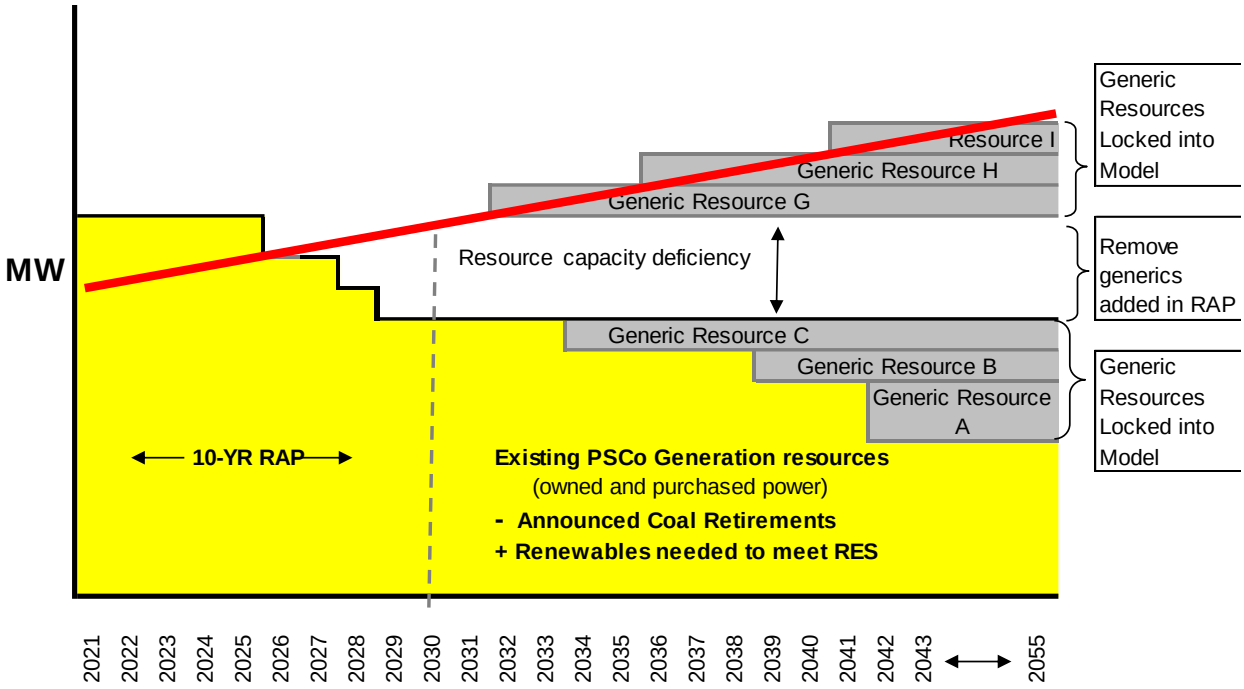
In Phase I modeling, we have also allowed generic resources to be placed both inside and outside of the Denver metro constraint and have represented delayed or avoided transmission costs of resources within the Metro constraint by removing the generic network upgrade/interconnection cost of $350/kW for generic resources that could be reasonably placed within the Denver metro area. For Phase I, this includes only ADERs. We have also excluded renewable and storage resources on the CPP from the $350/kW transmission cost adder because the Company has invested in the CPP upfront to enable new renewable and storage resources to connect to the Company's largest load center.

For Phase II modeling, the Company plans to use the results of the JTS Transmission Study to more closely approximate avoided transmission cost benefits of resources constructed within the Denver metro constraint and apply the costs as appropriate to bids based on bid location, as described above in this Section 2.13.

Development of Bid Portfolios

In the computer modeling of all bid portfolios, Public Service will employ a similar modeling convention as that approved by the Commission for use in prior ERPs wherein all generic resources added in years beyond the RAP (2032-2050) in the base capacity expansion model developed for Phase II modeling that incorporates all the approved updates and changes the Commission orders in its Phase I order, will be locked down in the EnCompass model. Note that the term "locked down" refers to the fact that a generic resource is hardwired into the EnCompass model to begin its operating life in a specific year as opposed to being modeled in a fashion where it has a floating in-service date that is ultimately selected by the model based on economics. All generic resources "locked down" in the model will still be capable of being economically dispatched with the rest of the fleet to meet customer load in a least-cost manner with the exception of generation such as wind and solar PV, which are not capable of being dispatched. These locked-down resources include all generic resources, whether gas, wind, solar, storage, or advanced technologies. Generic resources that were added in the RAP will be removed from the model, creating a capacity "gap" that the bids will fill. Figure 2.13-3 shows a graphical depiction of the generic resources that are locked down in the modeling.

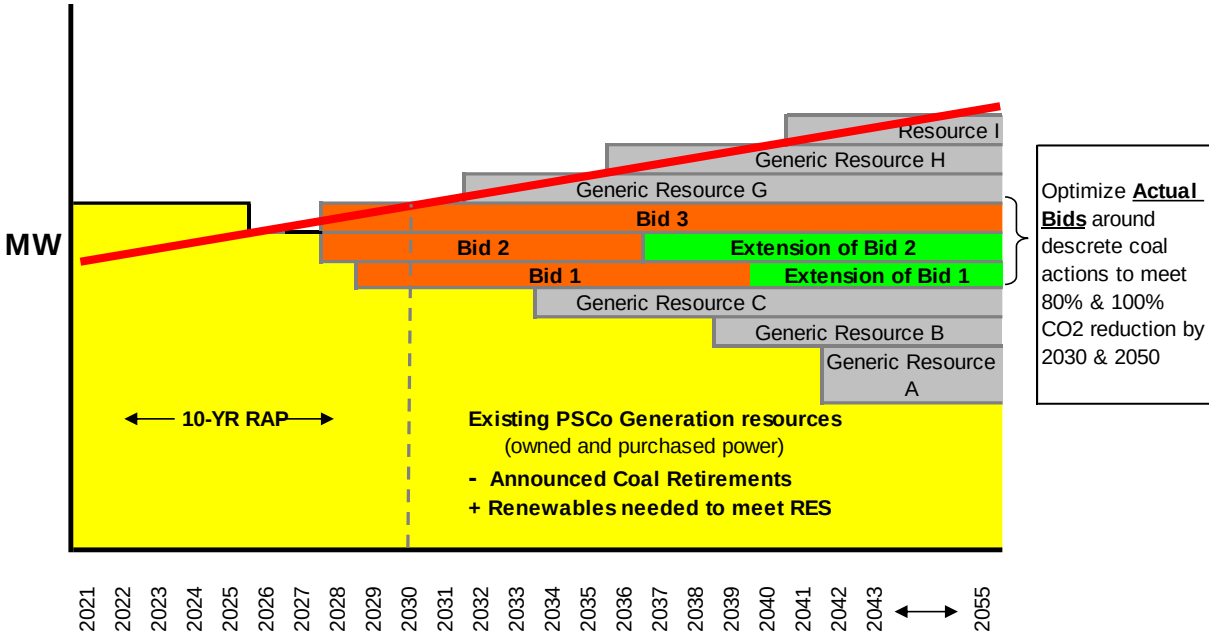
Figure 2.13-3 Depiction of EnCompass Model with Locked-down Resources



Due to the discrete size of the RAP generics, the set of removed resources will most likely result in a larger "hole" than the 2031 resource need identified in the L&R. In this likely event, a generic capacity-only purchase will be inserted in the years of the RAP to make the perceived "need" seen by the model exactly match the need determined using the approved L&R.

Figure 2.13-4 shows an example of how the bids will be extended (as necessary) to completely fill the gap created by removing the generic resources in the RAP. In this figure, Bid 3 has a term that extends to the end of the modeling period, so stands on its own. Bids 1 and 2 are shorter and are extended using the methodology for PPA and Company bids as discussed above.

Figure 2.13-4 Illustration of a Portfolio of Bids and Company Proposals



Reliability Rubric and Backend Portfolio Checks

The Company will conduct a similar process from the previous ERP to ensure final portfolios are reliable, but it has been updated based on subsequent experience in modeling for other Xcel Energy operating companies RFPs, as well as the new resource adequacy study the Company. An acknowledged failure in the 2021 ERP that was identified by stakeholders is that the Company clearly laid out in Phase I that it would perform back-end reliability testing on the portfolios but did not specify what actions it would take if portfolios failed testing. We are correcting that in this 2024 JTS by introducing the updated reliability rubric that will be used to test reliability and identify the actions to remedy if they fail reliability testing.

The rubric differs from the previous one in two major ways: (1) it has a more robust front-end process to minimize the likelihood of portfolios failing and (2) employs economic optimization to remedy portfolios without pre-determining specific resource additions.

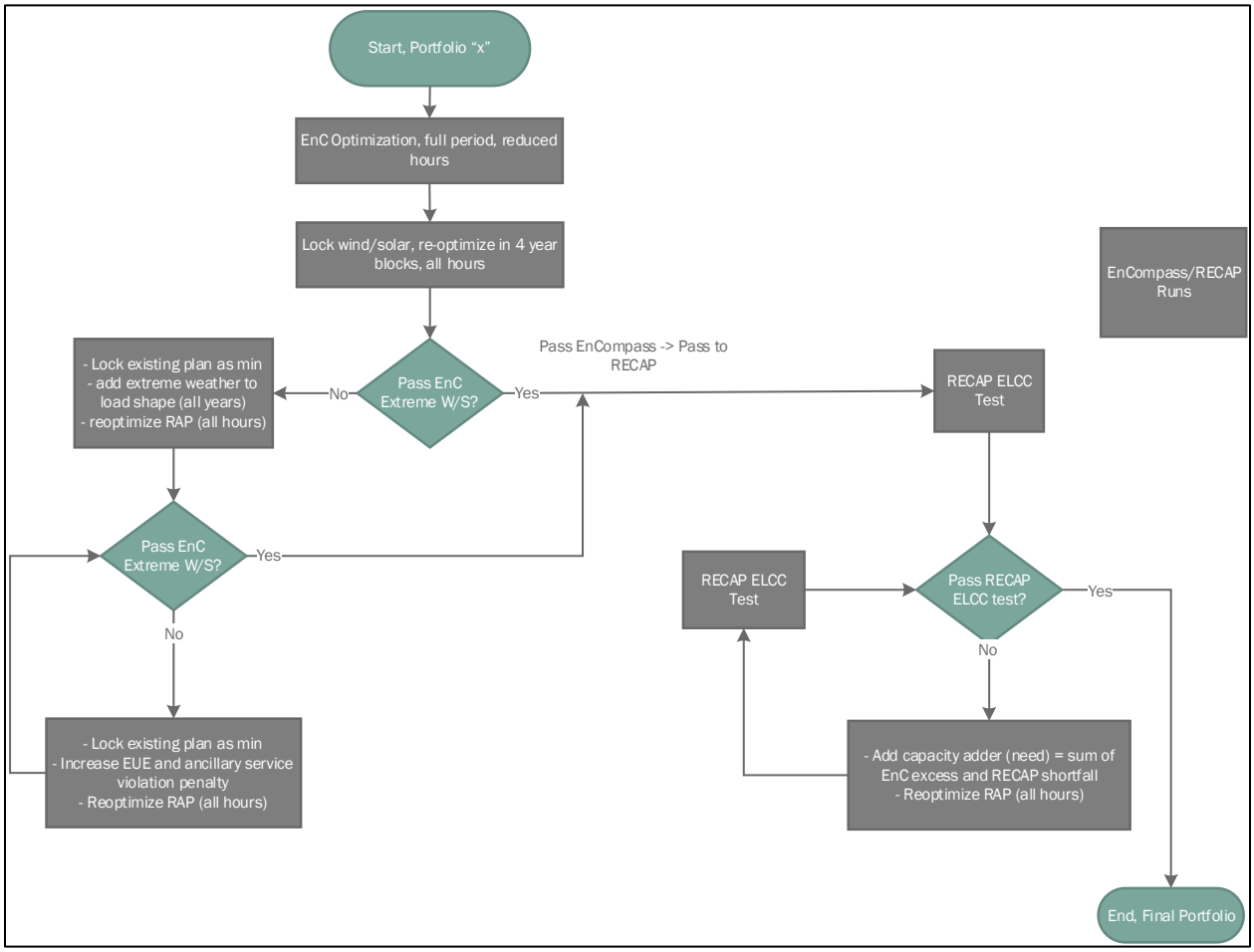
On the front end, the initial capacity expansion will utilize the new ELCC values for bids, which will reduce the likelihood that the portfolio fails to hit the reserve margin significantly. In addition, the Company will use a two-step capacity expansion to allow the model to first select resources based on a full view of the Planning Period, then lock in the selected wind and solar resources and conduct a second pass that uses much higher time-block granularity to more accurately represent load and resource diversity, thereby looking at energy adequacy in more hours. This second pass will more accurately value various capacity options such as storage, demand response, and firm dispatchable resources and create a portfolio that is much more likely to be reliable without secondary modification.

Portfolios will be tested using extreme summer and winter scenarios, and as of now, they are expected to be the same ones as were used in the 2021 ERP/CEP. These were based on weather and renewable production observed during Winter Storm Uri and July 2022. If future extreme events occur prior to issuing the Phase II RFP that indicate the need to update the scenarios, they would be updated to reflect those events. The portfolio will be required to not have any unserved energy or ancillary service violations in hourly production costing simulations of these two weather events to be deemed satisfactory. If a portfolio does not pass both these tests then the existing bids chosen thus far will be locked in, the extreme months will be added to the base load and renewable profile data, and the capacity expansion model will be rerun to add additional resources to solve these events. If for some reason the additional resources still do not pass the weather scenarios in the production costing testing, we will increase the penalties for unserved energy and ancillary service violations in the model and sequentially perform capacity expansion and production costing testing and repeat with continued raising of the penalties until a viable portfolio is found.

Once a portfolio has successfully passed this evaluation stage, we will verify that the PRM has been met by running the portfolio through the same RECAP model that was used in the RA Study. RECAP will be used to calculate the portfolio ELCC and verify that it satisfies the seasonal PRM. If both the summer and winter PRMs are met for all years of the RAP, the portfolio will be considered reliable and a viable alternative. If the PRM is not met, we will add a capacity “adder” to the season and year that is not met into EnCompass and reoptimize the RAP period (while locking in the resources that have been chosen thus far) to allow the model to select additional resources to meet the need. The adder will be the minimum amount needed to correct the deficit, or mathematically the difference between the amount EnCompass thought the portfolio was long versus RECAP sees as being short. The updated reliability rubric is shown below as Figure 2.13-5.

Unlike the reliability rubric used in the 2021 ERP & CEP, the updated version does not have any forced in resources and all resources are selected economically, subject to the input assumptions described above.

Figure 2.13-5 Updated Reliability Rubric



Post-Modeling Reliability Assessment

Each optimized portfolio of resources developed within the EnCompass model is reviewed by issue-specific SMEs to assess the expected reliability of the resulting Public Service system from three perspectives:

- *Transmission reliability*: assess the need for additional transmission upgrades to reliably deliver the output of the existing resources and new resources within each portfolio to load. This assessment is performed from both a real-time transmission operation perspective and a longer-term transmission planning perspective. To the extent additional transmission facilities are deemed necessary, the estimated cost of those facilities would be included in the overall cost of the portfolio. Due to timing and the nature of generic modeling in general, this evaluation was not done on the Phase I portfolios but will be done in Phase II. Expected transmission costs in Phase I were modeled via a

transmission cost adder on all generic resources. Transmission evaluation was done in a separate study in Phase I using portfolios similar in nature to the expected generic portfolios and further described in the Direct Testimony of Company witness Mr. Andrew W. Siebenaler.

- *Generation reliability:* assess whether each modeled portfolio contains sufficient levels and types of generation resources to reliably maintain the balance between load and generation on a real time basis. This includes a review of the detailed hourly generation dispatch results to assess whether the portfolio of resources could be expected to meet various reliability requirements, including but not limited to operating reserve (e.g., spin, non-spin, regulating), planning reserve margin, and flex reserve requirements in the absence of the perfect foresight the model has. To the extent this review identifies the need to make modifications as to how reliability requirements are being modeled or how resources are being modeled as contributing to those reliability requirements such modifications will be made and noted in the final report. Due to timing and the nature of the generic modeling, this evaluation was not done on the Phase I portfolios but will be done in Phase II.

- *Fuel supply reliability:* assess whether each portfolio contains sufficient firm fuel supply, natural gas storage, and gas storage withdrawal capability to reliably meet the projected peak gas demand requirements and hourly swings across the generation fleet. To the extent additional gas storage and withdrawal capability are identified, the estimated cost of those facilities would be included in the overall cost of the portfolio. Due to timing and the nature of the generic modeling, this evaluation was not done on the Phase I portfolios but will be done in Phase II.

Back-Up Bids

The overall process for selecting back up bids will remain the same from the last ERP, but the Company has some internal modeling lessons-learned to make this process more streamlined and effective. We will rerun the portfolio through EnCompass for each technology type (wind, solar, hybrid, storage, firm dispatchable, etc.) by locking in all resources except the selected type, removing the selected bids for the specific type, and only allowing bids of that type to come in as replacements. As an example for determining the wind backups, we will remove all wind from the Preferred Portfolio, lock in all other resources, and rerun the model only allowing new wind bids to come in. This process may be repeated multiple times to develop a robust pool of backups for each technology type.

Best Value Employment Metrics and Labor Considerations

Section 40-2-129, C.R.S., as further modified most recently by Senate Bill 23-292, requires the Company to obtain from bidders and provide to the Commission information relating to best value employment metrics ("BVEM") for each bid resource. When a utility proposes to construct new generation facilities of its own, the utility is required to provide the same information to the Commission. Accordingly, the RFP document contained in Volume 3 states that the Company can and will disqualify bids that provide insufficient BVEM as part of their bid packages. Each bid shall include the following information to be accepted as an eligible bid:

(I) the availability of training programs, including training through apprenticeship programs registered with the United States department of labor's office of apprenticeship or by state apprenticeship agencies recognized by that office for all apprenticeable trades required to effectively deliver the project to completion;

(II) employment of Colorado labor as compared to importation of out-of-state workers;

(III) the ability of the project to employ workers from traditionally underserved communities or disproportionately impacted communities as defined in § 24-4-109(2)(b)(II), C.R.S.;

(IV) how the project supports domestic manufacturing through the utilization of Colorado and domestically produced materials, including consideration of the potential for domestically manufactured materials being unavailable in the marketplace;

(V) long-term career opportunities; and

(VI) industry-standard wages, health care, and pension benefits.

To ensure that the BVEM information provided by either a bidder or the utility is substantive, § 40-2-129, C.R.S. requires: (1) provision of the BVEM documentation; or (2) in the alternative, certification of compliance with objective BVEM performance standards set forth in the solicitation document. The Commission may waive the requirements of (1) and (2) where a Project Labor Agreement ("PLA") is utilized.

In recent years, Public Service and labor interests have aligned on the fundamental need to obtain better, more thorough BVEM data from bidders through the competitive solicitation process. The problem regarding BVEM has been the lack of robust and detailed BVEM information from bidders. The generally scant information that has been provided by bidders in recent resource solicitations has limited the Commission's ability to consider the information in any sort of meaningful way. Independent power producers ("IPPs") have continued to argue that they are not in a position to provide detailed BVEM

information at the time of bid submittal, while labor organizations continue to argue the BVEM information that is provided is not sufficient for the Commission to make resource acquisition decisions. This has been particularly challenging for the Company, as the criticism shifts to the utility when the BVEM information that the Company can only solicit from bidders is considered inadequate by labor organizations and the Commission itself.

In an effort to improve the review and consideration of BVEM information, paragraph 69 of the USA approved in Phase I of the 2021 ERP & CEP set forth a multistep process in the Phase II bid evaluation to ensure consideration of BVEM in accordance with § 40-2-129(1)(a), C.R.S. First, the RFP directed bidders to include quantitative information with bid packages that addressed the BVEM statutory requirements, including access to apprenticeships and industry-standard wages and benefits. Second, a bid incorporating a PLA was deemed to meet threshold BVEM standards. Third, the Company agreed to screen bids based on BVEM and disqualify those that did not provide sufficient BVEM. Fourth, the Company would retain a labor economist to score the bids for advancement to computer modeling and the Company will provide a cumulative BVEM score for each portfolio in the Phase II Report require by Rule 3613(d).

Accordingly, the Company retained a labor economist to assist in scoring bids for the BVEM provided by bidders in Phase II of the 2021 ERP & CEP. Following consultation with and support from labor organizations (i.e., the Rocky Mountain Environmental Labor Coalition ("RMELC"), Colorado Building Construction Trades Council ("CBCTC"), and IBEW Local 111), the Company contracted with the Leeds School of Business at the University of Colorado–Boulder ("CU Leeds") to act as the labor economist and perform the BVEM review and scoring tasks contemplated by the USA. Specifically, the role of CU Leeds in Phase II was to score the BVEM for all bids advanced to computer-based modeling. CU Leeds developed a scoring rubric that focuses on a macro-level perspective and avoids individual value judgements, is informed by BVEM regulation, and assumes the quality of BVEM information is higher with more detail. Bidders received a score between 0 and 1 for each subcategory which was then averaged to develop major category scores which were then weighted to provide an overall score.

In its Phase II Decision, the Commission agreed that the thoughtful work performed by the labor economist in Phase II of the 2021 ERP & CEP Proceeding represents an enhancement of how BVEM can be incorporated into decision-making.[21] Therefore, the Company intends to similarly retain CU Leeds to implement a BVEM review and scoring process in Phase II of the 2024 JTS. The Commission also expressed an interest in seeing proposed changes to the model PPAs in the 2024 JTS aimed at clarifying standards for BVEM to ensure that IPPs and the Company are competing on a level playing field regarding BVEM and that the model PPAs account for the role that the Inflation Reduction Act ("IRA") can play in producing projects with high BVEM scores by incorporating factors such as the IRA's prevailing wage requirements.

[21] Decision No. C24-0052, at ¶268.

To further improve documentation and scoring consistency, the RFP bid forms have been updated to standardize the format by which all bidders will be required to provide and document BVEM information for review by the labor economist. Additionally, the model PPAs have been updated to require that each developer must abide by Senate Bill 23-292 and comply with the apprenticeship utilization law and prevailing wage law unless otherwise covered by a PLA as defined by § 24-92-303, C.R.S.

To facilitate receipt of robust BVEM information, the Company provides further guidance outlined below to prospective bidders to assist them with providing detailed and comprehensive BVEM information.

BVEM Information Guidance

(a) The availability of training programs, including training through apprenticeship programs registered with the United States Department of Labor, Office of Apprenticeship and Training. The utility or bidder shall provide, for example and as applicable, the following information for each craft the utility anticipates will work on the project:

(I) availability of training programs;

(II) the names of specific training programs available;

(III) the curriculum of the specific training programs;

(IV) the cost of worker training;

(V) the duration of the training programs;

(VI) the total number of hours of on-the-job training required;

(VII) the total number of classroom hours required;

(VIII) the licenses and certifications obtained, if any;

(IX) a copy of training program standards for each training program; and

(X) a statement whether the training programs are United States Department of Labor registered apprenticeship programs and are accredited to award college credits.

(b) The employment of Colorado workers as compared to importation of out-of-state workers. The utility or bidder shall provide, for example and as applicable, the following information for each craft the utility anticipates will work on the project:

(I) estimated number of workers by job classification;

(II) estimated length of time of service, including total man hours, by job classification;

(III) percentage of Colorado workers by job classification; and

(IV) percentage of project man hours earned by Colorado workers by job classification.

(c) Long-term career opportunities. The utility or bidder shall provide, for example and as applicable, the following information for each craft the utility anticipates will work on the project: job classifications, licenses, certifications and skills that will be applied and the long-term career opportunities for each job classification; and

(d) Industry-standard wages, health care, and pension benefits. The utility or bidder shall provide, for example and as applicable, the following information for each craft the utility anticipates will work on the project:

(I) range of wages by job classification;

(II) healthcare benefits by job classification;

(III) pension benefits by job classification;

(IV) prevailing wages and fringe benefits (healthcare benefits, pension benefits and other compensation) based on industry standards and the current Colorado labor agreements by job classification; and

(V) wages and fringe benefits (healthcare benefits, pension benefits and other compensation) by job classification.

2.14 CONFIDENTIAL AND HIGHLY CONFIDENTIAL INFORMATION

In this Section, the Company provides lists of the information related to the ERP plan proceeding that the Company considers public, confidential, and highly confidential as required by Rule 3604(j).

Concerning the EnCompass model that the Company used to represent the Public Service system[22] the model has millions of discrete data points that it uses to represent the Public Service system. The model is very much an organic model whose raw inputs are not in discrete files that can be provided or that would be easily understood or manipulated. Specific questions concerning derivations of EnCompass inputs will likely receive a specific and useful response. Public Service cautions that the Company cannot answer all non-specific EnCompass input questions. An example of a non-specific question would be: "Provide all EnCompass input files," or "Provide all EnCompass input files and assumptions." There are no such files, and the assumptions are too numerous to list in a productive manner. However, subject to Commission approved treatment of confidential data, the fully resolved EnCompass database (i.e. final model data only, without underlying support) is easily exportable from the model itself.

Public Information

The following Public Service information that is relevant to the 2024 JTS is or will be public information, either as a result of Public Service's filing the information in Phase I or Phase II of the 2024 JTS or due to a prior filing with the Commission, the State of Colorado, or federal agencies:[23]

Public Service Company of Colorado Information[24]

- Sales by Customer Class
- Revenue by Customer Class
- Number of Customers by Customer Class
- Sales by Tariff
- Revenue by Tariff
- Sales per Customer by Tariff
- Revenue per kWh by Tariff
- Sales Made to Wholesale Customers
- Revenue from Sales to Wholesale Customers
- Affiliate Transactions
- Reserve Margin
- Contingency Plan
- Resource Need for Resource Acquisition Period

[22] The model was used to produce alternative plans for the Phase I filing and will be used to evaluate the bids in a solicitation.
[23] Information listed is not all inclusive.
[24] Not including associated customer-specific information protected under the Commission's data privacy rules. Tariffs and classes with low customer counts would be treated the same as individual customer data.

- Renewable Energy Standard
- RES Compliance Position
- Renewable Energy Standard Adjustment
  - Balance
  - Forecast
- Sales and Demand Forecast
  - Total Sales
  - Total Demand
  - Sales by Customer Class
  - Demand by Customer Class

- All system simulation model output on an annual basis (costs, emissions, etc.)
- Annual Depreciation and Amortization Expense
- Estimated Average Service Life
- Annual Plant Hours Connected to Load
- Resource Fuel Types

<u>Transmission Resource Information</u>

- Operating Costs
- Wheeled Energy
- Wheeled Capacity
- Wheeling Revenue
- Purchase and Sale of Ancillary Services
- Peak Load
- Line Size and Length
- Capacity from Wheeling and Coordination Agreements
- Planned Additions
- Injection Capability

- Inflation Rate
- Federal Tax Rate
- State Tax Rate
- Discount Rate
- Weighted Average Cost of Capital
- Escalation Rates
- Emission Pricing
- Annual / Monthly Peak Demand & Energy
- DSM Forecast and Cost
- Load Management Resources
- Reserve Margin Requirements
- Spinning Reserve Requirement
- Monthly On/Off Peak Market Prices
- Market Purchase Emissions Rate Assumptions

- Blended Average Fuel Price Forecasts (not the proprietary forecasts) by Fuel Type and average historical costs by fuel type
- Surplus Capacity Credit Pricing & Limits
- Estimated Remaining Useful Lives
- PPA Contract Modification Terms
- Owned Unit and PPA In-Service Dates
- Owned Unit and PPA Retirement Dates
- Owned Unit and PPA Maximum Capacity
- Owned Unit and PPA Accredited Capacity
- Owned Unit Average Heat Rate
- Owned Unit Capacity Factors
- Owned Unit Availability Factors
- Generic Resources
    - Name Plate Capacity
    - Summer Peak Capacity
    - Capital Costs
    - Transmission Interconnection Costs
    - Transmission Grid Upgrade Costs
    - Firm Fuel Supply Costs
    - Book Life
    - Fixed O&M
    - Variable O&M
    - Heat Rate Curves
    - Forced Outage Rates
    - Typical Annual Maintenance Requirements
    - Emission Rates

- Capacity Additions (Expansion Plans)
- System Capacity and Energy Mix Aggregated by Technology Type, including total market purchases and sales
- System Emissions by Emission Type
- System Fuel Burn by Fuel Type
- Revenue Requirements for Capital Projects (not all Public Service capital projects are modeled) Aggregated by Technology Type
- Fixed Costs Including Fixed O&M and PPA Capacity Payments Aggregated by Technology Type
- Energy Costs Including Fuel, Variable O&M, and Energy Payments Aggregated by Technology Type
- Total Emission Costs by Emission Type
- Total System Curtailment
- Heat Map representation of hourly data
- Native System Hourly Load Patterns
- DSM Hourly Patterns

Phase II bid Information prior to public unredacted release

- Identification-masked bid ID
- Commercial Structure
- Technology Type
- Nameplate MW
- Inservice date year
- PPA Term length
- Storage duration
- ERZ/SRC Zone

Confidential Information

Public Service will seek to protect the following proprietary information as confidential information:

- Owned Unit Forecasted Hourly Typical Meteorological Year ("TMY") Wind Patterns
- Owned Unit Forecasted Hourly TMY Solar Patterns
- Owned Unit Contribution to Reserves
- Owned Unit Seasonal Deration Profiles
- Owned Unit Economic & Emergency Minimum
- Owned Unit Emission Rates
- Owned Unit Variable O&M
- Owned Unit Fixed O&M
- Owned Unit Fuel Consumed
- Owned Unit Average Maintenance Requirements
- Owned Unit Average Forced Outage Rate
- Owned Unit Availability Metrics such as EFOR
- Owned Unit Generation
- Owned Unit Energy Required
- Owned Unit Annual Data regarding unit commitment and dispatch
- Owned Unit Curtailment
- Owned Unit Capital Expenditures
- Owned Unit Rate Base
- Owned Unit Revenue Requirements
- Annual Market Import Constraints
- System Annual Fixed Gas Delivery Charges
- Hourly generation aggregated by technology type

Highly Confidential Information

Public Service will seek to protect the following proprietary information as highly confidential information:

- Owned Unit and PPA Delivered Fuel Costs
- Owned Unit and PPA Heat Rate Curves
- Owned Unit and PPA Discrete Maintenance Schedules
- Owned Unit and PPA Discrete Forced Outage Rates
- Owned Unit and PPA Historical Hourly Generation or Wind Speed Data
- Owned and PPA Hourly Marginal System or Unit Data
- Black Start Unit Designation
- Hourly Market Price Data
- Any information protected by the confidentiality clause of a PPA
- Fully resolved modeling database
- Standard modeling output files
- Bid information, including project name, identifying information, and pricing

HC Restricted Access to Commission, Staff, UCA, and IE

- Any customer-specific information, including data that does not comport with the Commission's data privacy rules and the "15/15 Rule" (i.e., Rule 1101, *et. seq*., Rule 3025, *et. seq.,* and Rule 3033, *et. seq*.;

- Any other information protected by a confidentiality clause of an existing non-disclosure agreement or similar agreement where the Company is contractually committed to keep certain information confidential, and the Company is bound to maintain such confidentiality, absent an order from this Commission to the contrary; and,

- Other bid information contained in bid packages (from the Company and other entities) not otherwise listed as highly confidential, confidential, or public information.

Information that Public Service will Provide Bidders

Public Service will provide the following Public Service-developed information to bidders with respect to their own bids after initial bid screening and before EnCompass modeling:

- Levelized Energy Cost or Levelized Cost of Capacity (LEC or LCC), as applicable
- Estimated Transmission Interconnection Costs, as applicable
- Estimated Transmission Network Upgrades, as applicable
- Gas Supply Costs, as applicable

Protection of Bid Information, Modeling Inputs and Assumptions, and Bid Evaluation Results

Public Service will seek to protect all bid information and bid evaluation results (including Company self-build proposals) that would reveal specific bid pricing or other bid information, as highly confidential information in accordance with the Commission's rules, until completion of the resource acquisition process (i.e., until the last contract for a resource that meets a portion of the 2024 JTS resource need is executed). Upon completion of the resource acquisition process, Public Service will post on its website the following bid information as required by Rule 3613(k):

- Bidder Name
- Bid Price (Utility Cost for Utility–Owned Proposals)
- Generation Technology Type
- Size of Facility
- Contract Duration (Expected Useful Life of Utility Resource)
- Purchase Option Details as relevant

Additionally, as required by Rule 3613(j), within fourteen months after the receipt of bids in the competitive acquisition process, the Company will file a proposal in the JTS proceeding that addresses the public release of all confidential and highly confidential information related to bids for potential resources and resources the utility proposed to build and own (e.g., the Phase II Report, the independent evaluator's report, and all documents related to these reports filed by the Company, parties, or the independent evaluator). Pursuant to the process set forth by Rule 3613(j), parties will have 30 calendar days after the Company files its proposal to file responses, and the Company may reply to any responses filed within ten calendar days. The Commission then issues an order specifying to the Company and other parties the documents that shall be refiled as public information.

2.15 OTHER 2024 JTS REQUIREMENTS

Comanche Unit 3 Capital Expenses and Projected O&M

Paragraph 86 of Decision No. C22-0459 (Phase I Decision in Proceeding No. 21A-0141E) requires the Company to present Comanche Unit 3's planned and unplanned capital expenditures as well as past and projected future O&M expenditures. Footnote 71 of the Phase I Decision further clarifies that the Commission's directive to forecast unplanned capital expenses will necessarily involve more uncertainty than forecasting planned capital expenditures, Public Service is directed to create a reasonable estimate based on Unit 3's historical data of the unplanned expenses Unit 3 will encounter going forward.

Accordingly, the Company provides the requested Comanche Unit 3 information as Appendix I to this Volume 2 Technical Appendix. The data provided in Appendix I aligns with the comparable data provided for purposes of evaluation of the Comanche 3 performance incentive mechanism ("PIM") in Proceeding No. 21A-0141E. The Company notes that for Phase I JTS modeling purposes, the Company utilized the Phase II Comanche 3 assumptions from the 2021 ERP & CEP.

Pawnee Hydrogen Blending Potential

Among the provisions of the USA regarding Pawnee, Paragraph 31 requires, in applicable part, that the Company discuss and continue to evaluate potential future hydrogen blending options at Pawnee and provide updated analysis of this potential, including technical potential and cost estimates, in each of its next two ERPs (i.e., this 2024 JTS and the 2026 ERP).

As discussed in Proceeding No. 22A-0563, the Pawnee Conversion CPCN Proceeding, the conversion of Pawnee from coal to gas as approved in the 2021 ERP & CEP facilitates the use of hydrogen at Pawnee; however, no determination on the future use of hydrogen has been made at this time.

In Proceeding No. 22A-0563, the Company presented a boiler study that was prepared by Babcock Power Inc. in April 2023 to, in part, explore the potential for future hydrogen blending at 30 percent hydrogen by volume at Pawnee. The results of the boiler study show that the Pawnee boiler can burn blended hydrogen up to 30 percent of total volumetric gas flow; however, the specific design details to accommodate hydrogen blending, including the support equipment that would be necessary for such a conversion, are dependent on how hydrogen would be supplied to Pawnee, which is unknown at this time.

The Company continues to discuss and evaluate the potential for the future use of hydrogen as agreed to in the USA. The potential for hydrogen to be used at the Company's gas plants is an evolving issue that will need to advance in the coming years. The Company will continue to evaluate options for the use of hydrogen going forward but

will need time to fully understand the potential for hydrogen mixing at its natural gas plants, including at Pawnee.

Historic O&M Costs for Company-Owned Generation Resources

Paragraph 515 of Decision No. C22-0459 (Phase I Decision in Proceeding No. 21A-0141E) directs the Company to provide in future ERP proceedings beginning with this 2024 JTS, the five most recent years of variable and fixed O&M costs for Company-owned generation resources.

Accordingly, Appendix J provides a summary of actual O&M expenditures for the five most recent years (2019-2023) for each Company-owned generation plant. The Company's Generation Business Area categorizes O&M costs in major cost categories for forecasting and accounting purposes and not specifically as variable or fixed costs. However, the O&M expenditures in Appendix J can generally be categorized as variable costs (i.e., costs associated with plant production and dispatch such as chemicals and water) and fixed costs to the extent feasible based on major cost categories (i.e., commodities, employee expenses, IT costs, labor, materials, miscellaneous, and outside services).

Transmission Interconnection Expansion Study

Paragraph 66 of the USA approved by the Commission provides that, following the 2021 ERP & CEP, the Company will study expansions of transmission interconnection to the PacifiCorp system. If a CPCN has been filed for any expansion of transmission interconnection to the PacifiCorp system ahead of either this 2024 JTS or the 2026 ERP Phase II competitive solicitation, the Company will model portfolios assuming the availability of any such project(s).

The Company performed the "Gateway South-Northwest Colorado 500 kV Interconnection Project - Interconnection Reliability Study," dated April 2022 (provided as Confidential Appendix K). The purpose of the study was to assess the reliability impact of the construction of an 80-mile 500 kV transmission line between Hayden Substation and a new "Little Snake Substation" on the Aeolis-Clover 500 kV transmission line. The study also considered the reliability impact of the construction of a 65-mile 500 kV transmission line between the Craig Substation and the "Little Snake Substation." The study attempted to understand how generation dispatch between the PSCo area in Eastern Colorado and the PACE area in Wyoming impacts the amount of flow possible on these two alternative lines. No CPCNs have been filed for any expansion of transmission interconnection to the PacifiCorp system as of the date of filing this 2024 JTS.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-95:
Colorado Commission Decision No. C25-0892

Decision No. C25-0892

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 25V-0480E

IN THE MATTER OF THE VERIFIED PETITION OF TRIAL STAFF OF THE COMMISSION, THE COLORADO ENERGY OFFICE, THE COLORADO OFFICE OF THE UTILITY CONSUMER ADVOCATE, AND PUBLIC SERVICE COMPANY OF COLORADO FOR A VARIANCE FROM ORDERING PARAGRAPHS 1 AND 2 OF DECISION NO. C18-0761 AND ANY OTHER REQUIREMENTS.

COMMISSION DECISION GRANTING JOINT PETITION WITH MODIFICATIONS AND ESTABLISHING PARTIES

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

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I. BY THE COMMISSION

A. Statement

1. Through this Decision we grant, with modifications, the Joint Petition that Trial Staff of the Public Utilities Commission ("Staff"), the Colorado Energy Office, ("CEO"), the Colorado Office of the Utility Consumer Advocate ("UCA"), and Public Service Company of Colorado ("Public Service" or the "Company") (collectively, "Joint Petitioners") filed on November 10, 2025 ("Petition"). We specifically grant the requested variance from Ordering Paragraphs 1 and 2 of Decision No. C18-0761 to modify the planned retirement date of Comanche Unit 2 ("Pueblo Unit 2") coal-fired facility from December 31, 2025, to December 31, 2026. In addition, we provide additional reporting and future filing direction regarding the proposed two-step process in the Petition and establish the parties to this Proceeding.

B. Background

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

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

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

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

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

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

C. Joint Petition

7. The Petition requests a variance from Ordering Paragraphs 1 and 2 of Decision No. C18-0761.[1] The requested variance would extend the planned retirement date of Comanche Unit 2 from December 31, 2025, to December 31, 2026. The Joint Petitioners assert that good cause exists to grant the variance and that the limited modification is in the public interest. The Petition also requests a shortened notice and intervention period of ten days and proposes a procedural schedule to allow for Commission deliberation and action by December 10, 2025.

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

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

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

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

10. Additionally, Joint Petitioners propose a two-step process for further evaluation in which the Company will provide two updates to the Commission on work in the extended review period. For the first step, the Company will provide a report to the Commission on March 1, 2026, which will include, among other things, an update on the repair and return to service status of Pueblo Unit 3, including forecasted cost of repairs, any resource options identified in collaborative work with the Joint Petitioners for potential near-term resource adequacy benefits, and other analysis relevant to the four areas outlined above.

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

D. Establishment of Parties

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

E. Party Responses

1. WRA

26. WRA supports a limited variance to extend the retirement of Unit 2 but conditions its support on the Commission's adoption of the "Alternate Plan,"[3] which it developed in collaboration with the Conservation Coalition and the Environmental Justice Coalition. WRA summarizes the Alternate Plan as follows: (1) place a status quo operational limitation on the operation of Unit 2 and Unit 3, designed to limit the total, combined generation from Units 2 and 3 to 3,942,000 MWh in 2026; (2) provide transparent, regular reporting related to the continued operations of Unit 2 and Unit 3 and associated costs incurred; and (3) institute an appropriately accelerated process to determine Public Service's resource adequacy position, identify near-term solutions, and provide direction on the continued operation of Unit 2 and Unit 3.[4]

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

[3] Attachment WRA-1 Alternate Plan.
[4] WRA Response at pp. 7-8.
[5] WRA Response at p. 8.

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

28. In addition to operational limits, WRA requests that the Commission require monthly reporting on a range of operational and financial metrics, including hourly generation, emissions, and costs associated with the continued operation of Unit 2 and the outage of Unit 3.[6] WRA also recommends that the Commission initiate a new application proceeding within 60 days of its decision on the Joint Petition to evaluate near-term resource adequacy and the future of Units 2 and 3.

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

(1) The MW produced each hour that Comanche 2 and Comanche 3 were operating;

(2) The total MWh produced by Comanche 2 and Comanche 3;

(3) The total CO_2, SO_x, NO_x, and PM10 emissions produced by Comanche 2 and Comanche 3;

(4) Any estimated future costs, and/or actual costs incurred, related to the outage of Comanche 3, including but not limited to repair costs and replacement energy costs, for which Public Service may seek recovery from Colorado ratepayers, along with a functional breakdown of the costs and an explanation for why the costs were incurred;

(5) Any updates on the repair and return to service status of Comanche 3, including the expected date for resuming operation;

(6) Any estimated future costs, and/or actual costs incurred, related to the extension of the life of Comanche 2, including but not limited to maintenance costs, return to operation and plant overhaul or upgrade costs, and fuel costs, for which Public Service may seek recovery from Colorado ratepayers, along with a functional breakdown of the costs and an explanation for why the costs were incurred; and,

[6] WRA Response at pp. 12-13.

(7) Large Load Reporting:

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

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

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

[7] WRA Response, Attachment WRA-1 at pp. 2-3.
[8] WRA Response at p. 13.
[9] WRA Response, Attachment WRA-1 at pp. 3-4.

2. Conservation Coalition

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

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

[10] Conservation Coalition Response at pp. 1-2.
[11] Conservation Coalition Response at pp. 3-4.
[12] Conservation Coalition Response at p. 5.

that the combined generation from Unit 2 and 3 in 2026 must not be allowed to exceed what is permitted from Unit 3 in 2026.[13]

34. Conservation Coalition also argues that the two-step process proposed in the Petition—consisting of a March 1, 2026 report and a June 1, 2026 application—is insufficient and untimely. The Coalition characterizes the proposed timeline as "too little, too late" and asserts that the Commission should instead initiate a litigated proceeding as soon as possible to evaluate the least-cost, lowest-emission options for the continued operation or retirement of Pueblo Units 2 and 3 after 2026.[14] The Coalition contends that such a proceeding should address whether Unit 3 should be repaired at all, whether Unit 2 should continue to operate in lieu of Unit 3 after 2026, and what near-term capacity or energy needs exist, along with the most appropriate options for meeting those needs.[15]

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

[13] Conservation Coalition Response at p. 7.
[14] Conservation Coalition Response at p 9.
[15] Conservation Coalition Response at p. 10.
[16] Conservation Coalition Response at p. 10.

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

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

3. EJC

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

[17] Conservation Coalition Response at pp. 13-14.

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

39. EJC notes that, under Senate Bill 21-272, the Commission has a statutory duty to minimize harms and correct the historical inequities experienced by DI communities such as Pueblo. To comply with its statutory equity mandate, EJC argues the Commission must thoroughly consider alternatives to address the outage of Unit 3 and approve an option that would best provide equity, address the historical inequalities, and minimize impacts and prioritize benefits in Pueblo. According to EJC, such alternatives include requiring operating guardrails that limit the overall generation at Unit 2 and Unit 3, utilizing market purchases while Unit 3 is offline, and reassessing the retirement date of Unit 3.[19]

4. City of Boulder

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

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

[18] EJC Response at p. 4.
[19] EJC Response at pp. 6-8.
[20] Boulder Response at p. 3.

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

42. Boulder argues that ratepayers should be shielded from the cost increases associated with the failure of Unit 3 and the proposed extension of Unit 2. Specifically, Boulder recommends that the Commission prohibit Public Service from recovering any incremental costs related to the continued operation of Unit 2 or the repair of Unit 3 unless and until the Company demonstrates prudence in a future proceeding.[22] Boulder also supports the proposed March 1, 2026 Step 1 report and encourages the Commission to use that report to evaluate updated retirement dates for Pueblo Unit 3 and to explore additional demand response and distributed energy resources as near-and mid-term solutions.[23] However, Boulder expresses concern that the proposed June 1, 2026 Step 2 application timeline is unrealistic, and argues that the timeline does not allow sufficient time for the Commission to approve new resources and for those resources to be acquired and placed in service in time to address any capacity shortfall in 2026.[24] Boulder also notes that while the Petition suggests Public Service may seek expedited approval to acquire new resources, it fails to explain how such acquisitions would be feasible outside of the typical ERP, demand-side management, or renewable energy standard proceedings.[25]

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

[21] Boulder Response at p. 6.
[22] Boulder Response at p. 7.
[23] Boulder Response at p. 7.
[24] Boulder Response at p. 7.
[25] Boulder Response at p. 8.

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

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

5. CRES

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

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

[26] Boulder Response at p. 8-9.
[27] Boulder Response at p. 10.
[28] CRES Response a p. 5.

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

6. CEC

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

48. CEC recommends the Commission impose several conditions to protect ratepayers from the financial consequences of Unit 3's outage. CEC notes that in prior instances of Unit 3 failures, the Commission has ordered disallowances through the Energy Cost Adjustment ("ECA"), and asserts that similar treatment is warranted here, where Unit 2 is being extended to serve as replacement power for Unit 3.[30] CEC argues there should be no presumption of prudence for any costs associated with Unit 2's extended operation, and that all costs related to Unit 3's outage should be disallowed. CEC recommends that the Company absorb all replacement power costs, including those associated with Unit 2, and return those costs to customers through the deferred balance in the next applicable ECA filing.

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

[29] CRES Response a p. 5.
[30] CEC Response at p. 6.

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

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

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

[31] CEC Response at pp. 6-7.
[32] CEC Response at p. 10.
[33] Proceeding No. 21A-0141E.
[34] CEC Response at p. 7.

7. Climax

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

8. Pueblo Intervenors

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

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

[35] Climax Response at p. 4.
[36] Pueblo Intervenors Response at pp. 2-3.
[37] Pueblo Intervenors Response at p. 4.

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

9. Public Comments

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

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

[38] Pueblo Intervenors Response at p. 7.

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

F. Joint Reply

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

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

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

[39] Joint Reply at pp. 2-3.

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

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

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

[40] Joint Reply at p. 6.
[41] Joint Reply at p. 5.

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

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

G. Findings and Conclusions

1. Unit 2's Extension

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

[42] Joint Reply at p. 4.
[43] Joint Reply at p. 6.
[44] Joint Reply at p. 7.

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

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

66. Regarding increasing peak demand, the most recent forecast provided in the Petition shows a 2026 peak demand of about 7,150 MW.[45] However, the Company's preferred updated base forecast that it endorsed in the JTS Rebuttal had a higher 2026 peak demand of 7,235.[46] Even though the Company had a higher demand forecast in its JTS Rebuttal, Public Service never requested or even suggested that it would need to extend Unit 2 to maintain resource adequacy. To be sure, Public Service raised concerns with its capacity position in recent proceedings, including in the JTS, but the Company never suggested the retirement date of Unit 2 should be reconsidered until now. An extension of Unit 2 was unnecessary until Unit 3 suffered its prolonged outage.

[45] Petition at p. 5.
[46] Hr. Ex. 117, Ihle Rebuttal, p. 30 filed in Proceeding No. 24A-0442E.

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

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

2. Two-Step Process

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

[47] Petition at p. 5.
[48] Petition at p. 6.

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

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

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

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

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

3. Additional Reporting

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

[50] Joint Reply at p. 5.

73. While we generally adopt the cadence and substance of the reporting set forth in the Alternate Plan, we find certain clarifications to be necessary. First, we clarify that any estimated material future capital costs for the repair of Unit 3 must be reported to the Commission before such costs are obligated. Second, for the information concerning large loads, Public Service must include such data in the same format as it presented in the JTS proceeding in which each large load is correlated to its industry, the probability of the load materializing, the requested in-service date, and the forecasted load by year through 2040.[51] In addition, out of all of the large loads listed, Public Service must clearly identify those that meet the Phase I Decision's requirements to be included in the base load forecast (*e.g.*, those loads that have executed an electric service agreement and interconnection agreement with the commercial principles including the fair notice provision).[52]

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

- The MW produced each hour that Unit 2 and Unit 3 were operating;
- The total MWh produced by Unit 2 and Unit 3;
- The total CO_2, SOx, NOx, and PM10 emissions produced by Unit 2 and Unit 3;
- Any estimated material future capital costs for the repair of Unit 3, before they are obligated;
- Any additional future or actual costs incurred related to the outage of Unit 3, including but not limited to repair costs and replacement energy costs, for which Public Service may seek recovery from Colorado ratepayers, along with a functional breakdown of the costs and an explanation for why the costs were incurred;
- Any updates on the repair and return to service status of Unit 3, including the expected date for resuming operation;

[51] *See* Hr. Ex. 141, Updated Base Forecast Large Load filed in Proceeding No. 24A-0442E.
[52] *See* Decision No. C25-0747 at ¶ 68 issued in Proceeding 24A-0442E on November 6, 2025.

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

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

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

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

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

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

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

4. Operational Limitations on Unit 2 and Unit 3

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

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

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

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

5. CEC's Resource Planning Recommendations

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

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

[57] CEC Response at p. 10.

II. ORDER

A. The Commission Orders That:

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

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

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

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

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

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

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

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

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

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

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

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

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

(S E A L)

ATTEST: A TRUE COPY

Rebecca E. White,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

ERIC BLANK[58]

MEGAN M. GILMAN

TOM PLANT

Commissioners

COMMISSIONER ERIC BLANK
DISSENTS, IN PART

[58]Eric Blank dissents in part.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-96:
Comanche Unit 2 Variance Petition

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

* * * * *

IN THE MATTER OF THE VERIFIED PETITION OF TRIAL STAFF OF THE COMMISSION, THE COLORADO ENERGY OFFICE, THE COLORADO OFFICE OF THE UTILITY CONSUMER ADVOCATE, AND PUBLIC SERVICE COMPANY OF COLORADO FOR A VARIANCE FROM ORDERING PARAGRAPHS 1 AND 2 OF DECISION NO. C18-0761 AND ANY OTHER REQUIREMENTS	)))))))))))	**PROCEEDING NO. 25V-____E**

VERIFIED PETITION OF TRIAL STAFF OF THE COMMISSION, THE COLORADO ENERGY OFFICE, THE COLORADO OFFICE OF THE UTILITY CONSUMER ADVOCATE, AND PUBLIC SERVICE COMPANY OF COLORADO FOR A VARIANCE FROM DECISION NO. C18-0761 AND ANY OTHER REQUIREMENTS, REQUEST FOR A SHORTENED NOTICE AND INTERVENTION PERIOD, AND REQUEST FOR APPROVAL OF ASSOCIATED PROCEDURES

Pursuant to Rules 1003 and 1304(e) of the Colorado Public Utilities Commission's ("Commission") Rules of Practice and Procedure, Trial Staff of the Colorado Public Utilities Commission ("Staff"), the Colorado Energy Office ("CEO"), the Colorado Office of the Utility Consumer Advocate ("UCA"), and Public Service Company of Colorado ("Public Service" or the "Company") (collectively, the "Joint Petitioners") seek a variance from Ordering Paragraphs 1 and 2 of Decision No. C18-0761, and any other decisions the Colorado Public Utilities Commission ("Commission") deems necessary, to modify the plan to retire Comanche Unit 2 from December 31, 2025, to December 31, 2026. Good cause exists to grant the variance, and the limited modification of the planned Comanche Unit 2 retirement date is in the public interest.

Colorado PUC E-Filings System

Electric resource planning ("ERP") proceedings have assumed the retirement of Comanche Unit 2 at year-end 2025 for several years dating back to 2018 when the Commission issued Decision No. C18-0761. The ensuing years have brought numerous changes in state policy, federal policy, resource planning, and power procurement. And, over that same timeframe, we have seen increasing peak load growth, requiring incremental resources to serve this demand. Most recently, supply chain challenges, tariff uncertainties, and changes to federal law have led to delayed in-servicing of resources that could have helped address this challenge, ultimately affecting Public Service's loads and resources projections. In addition, the Company has updated its resource accreditation and planning reserve margin development approaches based on industry best practices and resulting greater than anticipated resource needs.

A variance to the requirement to file an application to amend the Certificate of Public Convenience and Necessity ("CPCN") for Comanche Unit 2 and a one year extension of the plan to retire Comanche Unit 2 to December 31, 2026 is appropriate at this time and keeps the unit available to Public Service system operators in 2026. The Joint Petitioners believe that the continued operation of Comanche Unit 2 in 2026 is the most cost-effective approach to providing needed electricity for the system (as shown in the Company's loads and resources projections for summer 2026 in resource planning filings). Importantly, this Petition does not seek an order allowing for the operation of Comanche Unit 2 in perpetuity—it seeks a modest extension in the plan to retire the unit while setting up a process that will assess both resource options and mechanisms to continue orderly progress towards the State of Colorado's 2030 emissions reduction objectives.

To facilitate the timely resolution of the variance sought through this Petition, the Joint Petitioners request a shortened notice and intervention period of ten (10) days pursuant to Rule

1003(b), along with associated procedures set forth in this Petition. At this time, the Joint Petitioners are not requesting any further modification of existing resource plans beyond the variance requested here to address recent events and associated issues discussed in this Petition.

I. OVERVIEW

The orderly transition of coal-fired generation resources has been a centerpiece of Colorado resource planning for over a decade. In Public Service's 2016 ERP, Proceeding No. 16A-0396E, parties reached a settlement requiring the Company to propose portfolios in which Comanche Units 1 and 2 would retire early. The Commission approved that settlement, and Public Service then presented portfolios showing that retiring Comanche Units 1 and 2 in 2022 and 2025, respectively, would result in no additional cost to customers relative to portfolios in which the units retired in later years. The Commission-approved portfolio in Proceeding No. 16A-0396E resulted in a portfolio of resources to replace portions of the energy and capacity from Comanche Units 1 and 2. The Commission subsequently approved an accelerated depreciation and cost recovery schedule for Comanche Units 1 and 2 in Proceeding No. 17A-0797E.

In the Company's next resource plan, the 2021 ERP and Clean Energy Plan ("2021 ERP & CEP"), Proceeding No. 21A-0141E, modeling assumed that Comanche Unit 2 would retire on December 31, 2025. Numerous parties to the proceeding reached an Updated Non-Unanimous Partial Settlement Agreement ("USA") with Comanche Unit 3 retiring by January 1, 2031. The parties to the USA included a diverse set of parties, including the Joint Petitioners. The Commission approved the USA, and subsequently approved a portfolio of resources in Proceeding No. 21A-0141E based on modeling and analyses assuming that Comanche Unit 2 would retire on December 31, 2025.

These plans were reasonable and appropriate based on the information available at the time they were created and approved by the Commission. Recent events have resulted in challenges to those plans that generally fall into four areas: (1) the impact of the extended outage of Comanche Unit 3 on the Public Service system; (2) increasing peak load growth in the Public Service territory; (3) supply chain and geopolitical/macroeconomic impacts; and (4) reassessment of resource accreditation and planning reserve margin methodologies. While the Commission has multiple planning and other regulatory processes that are available to manage and address these issues, each of these issues layers atop one another, contributing to the need for the variance presented here.

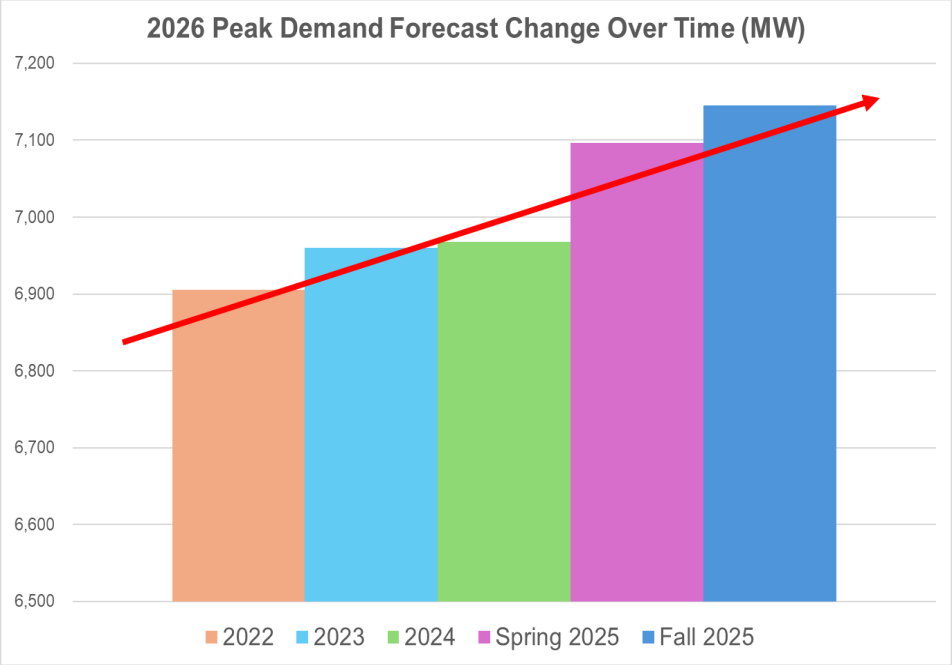
A. Comanche Unit 3 Outage and the Need for Comanche Unit 2 in 2026

Comanche Unit 3, which provides Public Service's system with 415 MW of accredited capacity, experienced an unplanned outage and is offline through at least June 2026. This outage, combined with the other layered issues described below, i.e., supply chain and geopolitical issues, and increasing peak demand, leads to this proposal to operate Comanche Unit 2 (which has a nameplate capacity of 335 MW and an accredited capacity of 296 MW) as a cost effective, near-term solution and supports the need for the requested variance. The Joint Petitioners propose a process below for a future report and application; the extension of Comanche Unit 2 facilitates time for that reporting and review to occur.

B. Increasing Peak Demand in Public Service Territory

Figure 1 below shows the peak demand forecast for summer of 2026 over time in megawatts ("MWs") year-over-year from forecasts developed in 2022 through the fall of this year. Each updated forecast illustrates the growing peak demand on the Company's system, reflective of the load growth forecasted by Public Service and focused on the year 2026.

Figure 1: Peak Demand Forecast Over Time (2022-2025) for Year 2026



C. Supply Chain and Geopolitical Issues

Supply chain and geopolitical issues also contribute to the challenge, impacting the viability of projects in various ways. The Company addressed this in the CEP Delivery Plan in September 2024 (also in Proceeding No. 21A-0141E). The Commission issued a final decision approving the CEP Delivery Plan parameters on January 14, 2025. In approving the CEP Delivery Plan with modifications, the Commission stated:

> Our Decision allows the generation and storage projects included within the CEP to continue advancing despite changing market dynamics and geopolitical uncertainties, including importantly potential future changes in federal law. Advancing these generation and storage projects as part of the overall determinations made through the course of this Proceeding moves Colorado forward towards achieving aggressive state emission reduction targets.[1]

The CEP Delivery Plan and associated evidentiary record illustrates the supply chain and geopolitical challenges that utilities and developers are navigating, along with the State of

[1] Decision No. C25-0024, at ¶ 2 (Jan. 14, 2025).

Colorado's response to them. While the CEP Delivery Plan assists with navigating these issues, it does not cure them.

D. Resource Accreditation and Planning Reserve Margin Changes

In accordance with the USA, the Company worked with an industry-leading consultant in the ongoing Just Transition Solicitation ("JTS") in Proceeding No. 24A-0442E to update its method for determining accredited capacity in a way that was more accurate and aligned with industry best practices.[2] That analysis revealed additional energy and capacity needs compared to prior modeling approaches. As such, the Company's need for resources—including in 2026 and 2027—identified through electric resource planning processes has increased over the coming years. The Commission continues to address overall energy and capacity needs through on-going planning proceedings, including the Near-Term Procurement ("NTP"), an innovative multi-stage electric resource plan solicitation, and other planning proceedings. However, just like the supply chain and geopolitical impacts on resource development and in-servicing, the updated accreditation and planning reserve margin approach affects the Company's loads and resources balance.

E. Next Steps

The Comanche Unit 3 development brought the Joint Petitioners together in requesting a variance to extend the planned retirement date of Comanche Unit 2. But simply obtaining a variance here is not the end of the work. Indeed, the variance sought through this Petition creates

[2] *See, e.g.,* Hrg. Ex. 102, Direct Testimony of Jon T. Landrum, at 30:12-20 (explaining that consultant Energy and Environmental Economics, Inc. ("E3") utilized their Renewable Energy Capacity Planning Model (RECAP), which is a loss of load probability model used to evaluate the resource adequacy of electric power systems. E3 originally developed RECAP in 2011 for the California Independent System Operator ("CAISO") and has since adapted the model for other Independent System Operators, including MISO, PJM, NYISO, and ISO-NE; utilities, including Duke Energy, the Sacramento Municipal Utilities District, Portland General Electric, Puget Sound Energy, Dominion Energy, Salt River Project, Public Service of New Mexico, and New Brunswick Power; and public utilities commissions, including the Oregon and Texas PUCs.").

an appropriate period of time to assess more permanent, long-term options, including resources that are projected to come on-line through on-going resource planning and other processes and consideration of updated retirement dates for Comanche Unit 2 and Comanche Unit 3. These efforts will include assessments of resource "portfolio" options for near-term, mid-term, and more permanent resource adequacy solutions, paired with emissions assessments of different approaches.

The Joint Petitioners propose two updates to the Commission on work in the extended review period in two different steps, as follows:

Step 1: March 1, 2026 Report. The Company will provide a report to the Commission on or before March 1, 2026. This report will include an update on the repair and return to service status of Comanche Unit 3, including forecasted cost of repairs, any resource options identified in collaborative work with the Joint Petitioners for potential near-term resource adequacy benefits, and other analysis relevant to the four areas outlined above. It will also include an initial plan to address on-going needs considering all available options, including not only plant extensions, but also expedited resource additions and demand-side options, with further refinement in Step 2. In addition, the Joint Petitioners intend to discuss the operations of Comanche Unit 2 over the course of the first quarter to determine appropriate operational parameters or approaches that may work for the unit while it operates in 2026, with a specific focus on operations after Comanche Unit 3 returns to service. The Step 1 report would include the results or status of these operations-focused discussions among the Joint Petitioners to keep the Commission apprised of potential options under consideration or options that the Company is comfortable pursuing.

Step 2: June 1, 2026 Application. For the second step, the Company commits to file an application for any additional variances or resource approvals, building on the Step 1 report and

depending on options identified through the collaborative work with the Joint Petitioners in the review period, by June 1, 2026. As part of that filing, the Company will include updated loads and resources tables and loss of load calculations that include analysis of new resources projected to come on-line from the NTP, JTS Phase II resource solicitation (in Proceeding No. 24A-0442E and to the extent known), or other relevant proceedings. The Company would likely seek consideration of any such requests on an expedited basis, e.g., a 120-day schedule. Options proposed for approval will focus on intermediate and long-term contracts, generation resource acquisitions, generation resource development, new distributed energy resource opportunities, potential demand response or programming changes beyond currently-approved program limits, or any other options that can benefit the Company's near- or mid-term resource adequacy position on either a temporary (e.g., a few years) or more permanent basis.[3]

These two steps make use of the extended review period with appropriate check-ins with the Commission. Moreover, and equally important, they set out an orderly process of next steps as the Company, in collaboration with the other Joint Petitioners, assesses the future operation of Comanche Unit 2, Comanche Unit 3, and other resource options.

II. REQUEST FOR VARIANCE

Rule 1003(c) sets forth the requirements for a variance petition:

(I) citation to the specific paragraph of the rule or decision from which the waiver or variance is sought;

(II) a statement of the waiver or variance requested;

(III) a statement of facts and circumstances relied upon to demonstrate why the Commission should grant the request.

[3] The other Joint Petitioners may or may not join this application and reserve their rights with respect to this future application.

(IV) a statement regarding the duration of the requested waiver or variance, explaining the specific date or event that will terminate it;

(V) a statement whether the waiver or variance, if granted, would be full or partial; and

(VI) any other information required by rule.

Decision No. C18-0761, at Ordering Paragraphs 1-2, states as follows:

> 1. The proposed early retirement of units 1 and 2 at the Comanche generation station, owned and operated by Public Service Company of Colorado (Public Service), is approved as part of its 2016 Electric Resource Plan (ERP), consistent with the discussion above.
>
> 2. Public Service shall file an application to amend the Certificates of Public Convenience and Necessity (CPCNs) for Comanche units 1 and 2, pursuant to 4 Code of Colorado Regulations (CCR) 723-3-3103 of the Commission's Rules Regulating Electric Utilities, as modified by this Decision, consistent with the discussion above."

Among other things, Ordering Paragraph 1 approves the Company's plan to retire Comanche Unit 2. Ordering Paragraph 2 requires a limited scope CPCN amendment filing associated with such retirement. The Joint Petitioners seek relief in the form of a variance from the Commission's directive to file a CPCN amendment to effectuate a retirement of the unit by the end of this year, as well as any other requirements the Commission deems necessary. The discussion that follows addresses each rule requirement in more detail.

A. Rule 1003(c)(I): citation to the specific paragraph of the rule or decision from which the waiver or variance is sought.

Joint Petitioners seek a variance from Ordering Paragraphs 1 and 2 of Decision No. C18-0761; specifically the requirement to file for a CPCN amendment to retire Comanche Unit 2

consistent with the Company's 2016 ERP in Decision No. C18-0761 and any other requirements the Commission deems necessary.

B. Rule 1003(c)(II): a statement of the waiver or variance requested.

The Joint Petitioners seek a variance of 365 days, i.e., until December 31, 2026, for the planned retirement of Comanche Unit 2, with the CPCN filing requirement held in abeyance until that time. In Step 2 defined above, the Joint Petitioners or the Company may bring a longer variance request to the extent necessary. Any longer extension, however, is not at issue here in this proceeding. In addition, neither the Company nor the Joint Petitioners seek any ratemaking relief as part of this Petition. Any such requests can be brought forward and addressed by the Commission in other appropriate proceedings.

C. Rule 1003(c)(III): a statement of facts and circumstances relied upon to demonstrate why the Commission should grant the request.

Section II above outlines the facts, circumstances, and need for the variance requested by the Joint Petitioners. The variance and 365-day extension allows time for the two-step process outlined above to assess future plant operations and resource options. In addition, it provides a level of certainty to system operators and the workers at the unit by having a date certain for the plan to retire the unit. Moreover, it is worth noting that, viewed from a greenhouse gas ("GHG") emissions perspective, a Comanche Unit 2 extension will result in GHG emissions in 2026 from the unit that would not otherwise have occurred; however, that should be viewed in the context of a Comanche Unit 3 outage, where the emissions from the larger Comanche Unit 3 will *not occur*, leading to lower GHG emissions in the first half of 2026 (along with lower GHG emissions in the latter part of 2025). The Company also intends to evaluate the emissions impact, including other

pollutants beyond GHG emissions, and to work with the Colorado Department of Public Health and Environment on that effort.

D. Rule 1003(c)(IV): a statement regarding the duration of the requested waiver or variance, explaining the specific date or event that will terminate it.

The duration of the requested variance is through December 31, 2026. The variance will terminate on that date absent an additional variance request and the subsequent grant of the request by the Commission.

E. Rule 1003(c)(V): a statement whether the waiver or variance, if granted, would be full or partial.

The variance is partial as it is time-limited through December 31, 2026, absent a further variance.

F. Rule 1003(c)(VI): any other information required by rule.

The Joint Petitioners are not aware of any additional information required by rule.

IV. REQUEST FOR SHORTENED NOTICE AND INTERVENTION PERIOD AND RELATED PROCEDURES

The Joint Petitioners request a shortened notice and intervention period pursuant to Rule 1003(b), along with related procedures. Rule 1003(b) states: "If a petition requests a waiver or variance to be effective less than 40 days after the date of filing, the petition must include a request to waive or shorten the Commission notice and intervention period found in paragraph (d) of rule 1206."

The Joint Petitioners request approval of the procedures and schedule set forth below, which feature: (1) a shortened notice and intervention period of ten calendar days; (2) the filing of responses to the petition *with* any motions to intervene; and (3) a two-calendar day reply timeline

for the Joint Petitioners to address any responses.[4] The procedures are set forth with specific dates, including a proposed date for Commission deliberation and action.

Process Step	***Timing***
Joint Petition	+0 (November 10, 2025)
Commission accepts Petition	(November 12, 2025)
Intervention Deadline (petition responses included with interventions)	+10 calendar days after filing (November 20, 2025)
Joint Petitioner Reply	+6 calendar days after response (November 26, 2025)
Commission Deliberation	December 3, 2025
Commission Action	December 10, 2025

V. CONCLUSION AND REQUEST FOR RELIEF

The Joint Petitioners ask for swift Commission action on this Petition, and time is of the essence given the upcoming retirement date for Comanche Unit 2. The Joint Petitioners appreciate the Commission's prompt consideration of this request and the related procedural requests.[5]

The Joint Petitioners request approval of:

- A variance from Ordering Paragraphs 1 and 2 of Decision No. C18-0761 and any other requirements deemed necessary by the Commission.
- A shortened notice and intervention period of ten days.
- The procedures for consideration and decision on this Petition set forth above.

The Joint Petitioners further request that the Commission grant this Petition without a hearing.

[4] The Joint Petitioners are providing electronic courtesy service of this Petition to all parties to Proceeding No. 16A-0396E, Proceeding No. 21A-0141E, and Proceeding No. 24A-0442E given the request for a shortened notice and intervention period and associated procedures here.

[5] The Joint Petitioners ask the Commission to ensure that the relief sought in this petition will not interfere with the Company's planned or in-progress acquisition or interconnection of new generating resources. Nothing in this proposal shall be construed as the Joint Petitioners' request to alter the Company's proposal to acquire new resources through the NTP and the JTS. The Joint Petitioners strongly encourage the Commission to ensure that the NTP remains on the procedural schedule that the Commission approved, and to move as quickly as possible to conclude the Phase I JTS and proceed to Phase II of the JTS.

Dated this 10th day of November 2025.

Respectfully submitted,

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ATTORNEYS FOR PUBLIC SERVICE COMPANY OF COLORADO

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

*** * * ***

IN THE MATTER OF THE VERIFIED PETITION OF TRIAL STAFF OF THE COMMISSION, THE COLORADO ENERGY OFFICE, THE COLORADO OFFICE OF THE UTILITY CONSUMER ADVOCATE, AND PUBLIC SERVICE COMPANY OF COLORADO FOR A VARIANCE FROM ORDERING PARAGRAPHS 1 AND 2 OF DECISION NO. C18-0761 AND ANY OTHER REQUIREMENTS	)	**PROCEEDING NO. 25V-____E**

VERIFICATION OF JACK W. IHLE

STATE OF COLORADO)
CITY AND COUNTY OF DENVER) SS:

I, Jack W. Ihle, being duly sworn, do hereby depose and state that I am the Regional Vice President, Regulatory Policy, at Xcel Energy Services Inc., and am an authorized agent for Public Service Company of Colorado. I have read the foregoing Verified Petition of Trial Staff of the Commission, the Colorado Energy Office, the Colorado Office of the Utility Consumer Advocate, and Public Service Company of Colorado for a Variance from Decision No. C18-0761 and Any Other Requirements, Request for Shortened Notice and Intervention Period, and Request for Approval of Associated Procedures. The facts set forth therein are true, accurate, and correct to the best of my knowledge, information, and belief.

Dated at Denver, Colorado, this 10th day of November, 2025.

Jack W. Ihle
Regional Vice President, Regulatory Policy
3500 Blake Street
Denver, Colorado 80205

Subscribed and sworn to before me this 10th day of November, 2025.

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

Notary Public

My Commission expires 4/18/2028

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	))))))	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-97:
Colorado Commission Decision No. C25-0747

Decision No. C25-0747

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 24A-0442E

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF ITS 2024 JUST TRANSITION SOLICITATION.

PHASE I COMMISSION DECISION

Issued Date: November 6, 2025
Adopted Date: August 6, 13, 18, 21, and 27, 2025

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I. BY THE COMMISSION

A. Statement

1. Through this Decision, the Commission approves, with modifications, the Verified Application for Approval of a 2024 Just Transition Solicitation ("JTS") filed by Public Service Company of Colorado ("Public Service" or the "Company") on October 15, 2024. The JTS ties to Public Service's most recent Electric Resource Plan ("ERP") in Proceeding No. 21A-0141E that included a Clean Energy Plan ("CEP") (the "2021 ERP/CEP"). The 2021 ERP/CEP was filed in accordance with § 40-2-125.5, C.R.S. and established the plan for

Public Service to reduce its carbon dioxide emissions by 80 percent by 2030. The JTS continues to execute the plan from the 2021 ERP/CEP and, as initially filed, seeks to address Public Service's need for additional resources from 2029 through 2031, including replacement resources for the Pueblo Unit 3 coal-fired power plant that is set to retire by January 1, 2031.

2. Through this Decision, we establish a pathway for Public Service to acquire the generation and storage resources necessary to replace Unit 3, reliably serve existing and future customers, continue progress on emissions reductions, and help ensure a just transition. At the same time, we require additional customer protections to help protect Colorado ratepayers from the risks associated with investments made to serve prospective large loads like data centers. We also largely adopt Public Service's proposed tools for ensuring a just transition, including community assistance payments, modeling approaches that encourage the selection of new resources within certain just transition communities, and the carbon free future development ("CFFD") proposal. Ultimately, this Decision provides the necessary regulatory certainty for Public Service to move to Phase II in which the Company will solicit and evaluate various bids for new generation and storage resources, compile these bids into various resource portfolios, and present its preferred resource portfolio in the Phase II 120-Day Report.

3. Consistent with the discussion below, we authorize Public Service to implement competitive bidding processes for acquiring cost-effective resources to meet its projected resource need through 2033 and model such bids consistent with the modeling processes and assumptions set forth in this Decision. Among our directives in this Decision, we also address the Company's proposed conforming bid policy, adopt the Company's best value employment metrics ("BVEM"), address certain rule waiver requests, and require the Company to file for approval of an independent evaluator to assist in the established solicitation process.

4. This Decision builds on past ERP processes integral to Colorado's iterative proceedings that establish resource need, address critical state regulatory requirements, and – of particular importance here – continue imperative processes to further support Colorado communities towards a diverse and economically sustainable energy future. In addition, the processes approved in this Decision create flexible opportunities for committed large load growth, while at the same time protecting Colorado ratepayers from development that is more speculative by providing a framework to update the load forecast in the Phase II process.

5. As discussed in detail below, these dynamic competitive bidding processes paired with confirmation of community assistance considerations and credit modeling designed to balance state priorities, ratepayer impacts, environmental impacts, and community support, and at the same time maintain a reliable and robust energy future. While no specific resources are selected or determined at this phase of the process, the process and considerations weighed in it set in motion important future determinations both as next steps and concurrent with ongoing acquisitions to meet resource needs.[1]

B. Background

6. The Commission's ERP Rules, set forth at 4 *Code of Colorado Regulations* ("CCR") 723-3-3600, *et seq*., serve two primary functions. First, the rules require a regular, periodic examination of an electric utility's energy sales and demand forecasts as compared to an assessment of its existing resources to ensure that sufficient generation will be available to meet customer needs in the future. Second, the Commission's review and approval of an ERP ensures

[1] Not only is Colorado meeting future acquisition needs here, but it continues to fill resource needs in an ever-changing environment through ongoing processes in its ongoing and most recent ERP, Proceeding No. 21A-0141E, both through a stepped approach addressing bid flexibility and in near term project acquisition opportunities. While each of these proceeding processes is separate, they work in concert through stepped and phased considerations to best ensure prudent paths forward to address Colorado's energy needs.

that the utility acquires a cost-effective mix of additional resources consistent with the state's public policy objectives.

7. As established in the ERP Rules, for decades Colorado electric utilities have used competitive bidding to procure additional resources to meet identified future resource needs. An ERP thus describes in detail how the utility will evaluate the bids and proposals submitted in response to Requests for Proposals ("RFPs"), including the inputs and assumptions to its bid evaluation models (*e.g.*, natural gas prices, coal prices, carbon costs, discount rates, and integration costs for intermittent resources), and how it will apply resource selection criteria.

8. The ERP process includes two phases. In Phase I, the Commission reviews and may approve, or approve with modifications, the utility's plan to acquire new utility resources. In Phase II, the Commission determines whether the utility should be granted a presumption of prudence for pursuing the acquisition of particular resources.

9. Rule 4 CCR 723-3-3617(c) describes the contents of the Commission's Phase I decision:

> The Commission decision approving or denying the plan shall address the contents of the utility's plan filed in accordance with rule 3604. If the record contains sufficient evidence, the Commission shall specifically approve or modify: the utility's assessment of need for additional resources in the resource acquisition period; the utility's plans for acquiring additional resources through an all-source competitive acquisition process or through an alternative acquisition process; components of the utility's proposed RFP, such as the model contracts and the proposed evaluation criteria; and, the alternate scenarios for assessing the costs and benefits from the potential acquisition of increasing amounts of renewable energy resources, demand-side resources, or Section 123 resources.

10. Phase II begins after the Commission issues its Phase I decision. Public Service will issue its RFPs, receive competitive bids and utility-owned proposals, and file a report in this Proceeding no later than 120 days after the bids are received in accordance with Rule 4 CCR 723-3-3613(d) ("120-Day Report"). The 120-Day Report will present an evaluation of all proposed resources, based on the criteria established in the Phase I decision (*e.g.*, the base modeling inputs and assumptions to be used in developing optimized resource portfolios and the sensitivities that "re-price" optimized portfolios using alternative values for selected inputs and assumptions).

11. At the end of Phase II, the Commission issues a final decision that will approve, condition, modify, or reject the utility's preferred cost-effective resource plan. Rule 4 CCR 723-3-3613(h) describes the contents of a Phase II decision:

> Within 90 days after the receipt of the utility's 120-day report under paragraph 3613(d), the Commission shall issue a written decision approving, conditioning, modifying, or rejecting the utility's preferred cost-effective resource plan, which decision shall establish the final cost-effective resource plan. The utility shall pursue the final cost-effective resource plan either with a due diligence review and contract negotiations, or with applications for CPCNs (other than those CPCNs provided in paragraph 3611(e)), as necessary. In rendering the decision on the final cost-effective resource plan, the Commission shall weigh the public interest benefits of competitively bid resources provided by other utilities and non-utilities as well as the public interest benefits of resources owned by the utility as rate base investments. In accordance with §§ 40-2-123, 40-2-124, 40-2-129, and 40-3.2-104, C.R.S, the Commission shall also consider renewable energy resources; resources that produce minimal emissions or minimal environmental impact; energy-efficient technologies; and resources that affect employment and the long-term economic viability of Colorado communities. The Commission shall further consider resources that provide beneficial contributions to Colorado's energy security, economic prosperity, environmental protection, and insulation from fuel price increases.

12. Public Service shall pursue the final cost-effective resource plan in accordance with the Phase II decision, either with due diligence reviews and contract negotiations, or with applications for Certificates of Public Convenience and Necessity ("CPCNs"), as necessary, in accordance with Rule 4 CCR 723-3-3613(h).

13. Additionally, while the above rules and competitive bidding processes are foundational to the Commission's utility resource planning process, subsequent legislative changes, including Senate Bill ("SB") 19-236 further overlay CEP considerations on the Commission's ERP processes. Generally, SB 19-236 enacted § 40-2-125.5(1)(e), C.R.S., which declares the statewide importance of promoting cost-effective clean energy and new technologies

and reduction of carbon dioxide emissions from the Colorado electric generating system and includes that "[a] bold clean energy policy will support this progress and allow Coloradans to enjoy the benefits of reliable clean energy at an affordable cost."[2]

14. Just like SB 19-236 iterates on the Commission's ERP process, the Commission's ERP decisions—particularly since the 2012 ERP—are iterative. These ERP decisions build on continuous planning processes, including important state goals that advance a strategic balance of objectives, including maintaining reliability, achieving emission reduction targets, ensuring continued affordability, and supporting local communities. In the 2016 ERP, for example, litigation resulted in consideration of the social cost of carbon ("SCC"), in addition to other pertinent factors. Likewise, the Company's voluntary proposal for the accelerated retirement of Unit 2, which will be implemented at the end of this calendar year, created the opportunity for additional, diverse and reliable resources in addition to important opportunities for transmission interconnection capacity. These opportunities have since been realized through subsequent proceedings,[3] and the ongoing electric resource planning processes. The 2016 ERP, the 2021 ERP/CEP, and other Commission planning decisions relied on the accelerated retirement of Unit 2 when approving the acquisition of additional resources and in planning for the transmission capacity that these new resources would use.[4] The timing and impact of Unit 2 further underlies

[2] Section 40-2-125.5(3)(a), C.R.S., requires that, in addition to the other requirements of the section, Public Service shall meet the following clean energy targets: "(I) By 2030, the qualifying retail utility shall reduce the carbon dioxide emissions associated with electricity sales to the qualifying retail utility's electricity customers by eighty percent from 2005 levels[; and] (II) For the years 2050 and thereafter, or sooner if practicable, the qualifying retail utility shall seek to achieve the goal of providing its customers with energy generated from one-hundred-percent clean energy resources so long as doing so is technically and economically feasible, in the public interest, and consistent with the requirements of this section."

[3] *See*, *e.g.*, Hr. Ex. 101, Pascucci Direct Testimony, p. 11 in Proceeding No. 24A-0140E (noting interconnection replacement and substation use given the anticipated shutdown of Unit 2).

[4] *See* Verified Application for Approval of CPCN for Rocky Mountain Project and Arroyo 2 Project, p. 5 in Proceeding No. 24A-0140E.

the Company's claims regarding the continued need for and support of Unit 3.[5] Through the years, the Commission has reviewed parallel cost calculation and depreciation filings for decommissioned generating units, ensuring regulatory certainty and reducing rate impacts.[6]

15. The iterative nature of the Commission's ERP processes also appears in the development of the JTS, which first appears in the Updated Non-Unanimous Partial Settlement Agreement ("USA") that Public Service filed in the 2021 ERP/CEP in April 2022. The JTS ties to provisions in the USA that Unit 3 will retire no later than January 1, 2031. The Unit 3 retirement date in the USA harmonizes with the timing of this JTS, which is intended to help procure the replacement generation for Unit 3 in a way that will help ensure a just transition for the Pueblo community.[7] Because the JTS solicitation was intended to address Public Service's resource needs from 2029 through 2031, it allowed the resource acquisition period ("RAP") in the 2021 ERP/CEP to be truncated such that Public Service would only acquire resources with in-service dates on or before December 31, 2028.

16. The USA requires Public Service to commence the JTS no later than June 1, 2024, and the Commission approved this date in Decision No. C22-0459 ("CEP Phase I Decision") in the 2021 ERP/CEP. On April 22, 2024, however, Public Service filed an Unopposed Motion for Variance to File Just Transition Solicitation no later than August 1, 2024. The Commission granted this Unopposed Motion. Subsequently, on July 17, 2024, Public Service filed another Unopposed Motion to delay the filing of the JTS to no later than October 15, 2024, which the Commission also granted.

[5] *See, e.g.*, Hr. Ex. 164, Pascucci Supplemental Testimony, Rev. 1, p. 17 in the 2021 ERP/CEP (stating that the accelerated retirement of Unit 2 necessitates the construction of an auxiliary boiler for Unit 3).
[6] *See*, *e.g.*, Proceeding No. 16A-0231E.
[7] *See* 2021 ERP/CEP USA at ¶ 43.

C. Procedural History

17. On October 15, 2024, Public Service filed a Verified Application of Public Service Company of Colorado for Approval of its 2024 Just Transition Solicitation ("Application"). The Company submitted Direct Testimony of nine witnesses in support of the Application.

18. In conjunction with its application, on October 15, 2024, Public Service filed an Omnibus Motion for Extraordinary Protection of Highly Confidential Information, and for Partial Waiver of Rules 3606(b), 3612(a), 3618(b)(I), 3613(a) and 3613(d) and waiver of Rule 3608(c)(III)-(IV) ("Omnibus Motion").

19. Through Decision No. C24-0872-I, issued November 22, 2024, the Commission, among other things, set the matter for hearing before the Commission *en banc* and established parties to the Proceeding. Parties consist of the following: Public Service, Trial Staff of the Commission ("Staff"); the Utility Consumer Advocate ("UCA"), the Colorado Energy Office ("CEO"); Holy Cross Electric Association, Inc. ("Holy Cross"); Colorado Energy Consumers ("CEC"); Climax Molybdenum Company ("Climax"); Walmart Inc. ("Walmart"); Natural Resources Defense Council ("NRDC") and Sierra Club (collectively, the "Conservation Coalition"); Western Resource Advocates ("WRA") and Southwest Energy Efficiency Project ("SWEEP"); Healthy Air and Water Colorado ("HAWC"); GreenLatinos, GRID Alternatives, NAACP State Conference CO-MT-WY, Pueblo Branch ("NAACP"), Roots to Resilience and Vote Solar (collectively, the "Environmental Justice Coalition" or "EJC"); Pivot Energy Inc. ("Pivot Energy"); the Colorado Renewable Energy Society ("CRES") and the Physicians for Social Responsibility Colorado ("PSR CO") (collectively, "CRES/PSR"); the Board of County Commissioners of Pueblo County ("Pueblo County Board"), City of Pueblo, and Pueblo Economic Development Corporation ("PEDCO") (collectively, "Pueblo Intervenors"); Moffat County,

Colorado ("Moffat County") and the City of Craig, Colorado ("City of Craig") (collectively "Moffat and Criag"); the Town of Hayden, Colorado ("Town of Hayden") and Routt County, Colorado ("Routt County") (collectively, "Routt County Governments"); Colorado Communities for Climate Action ("CC4CA"); Interwest Energy Alliance ("Interwest"); the Colorado Independent Energy Association ("CIEA"); Onward Energy Management LLC ("Onward"); the Coalition for Community Solar Access ("CCSA"); the Eastern Metro Area Business Coalition ("Business Coalition"); the Colorado Solar and Storage Association ("COSSA"), the Solar Energy Industries Association ("SEIA"), and Advanced Energy United ("AEU") (collectively, the "Clean Energy Industry"); and the Office of Justic Transition ("OJT").[8]

20. Through Decision No. C24-0876-I, issued November 27, 2024, the Commission deemed the Application complete for purposes of § 40-6-109.5, C.R.S., and allowed the Application to automatically deem complete on November 30, 2024.

21. Through Decision No. C24-0941-I, issued December 23, 2024, the Commission, among other things, referred future discovery disputes to an Administrative Law Judge and set a deadline for Staff to make a filing addressing the Independent Transmission Analyst ("ITA") scope of work. The Commission also addressed certain requested waivers in the Company's Omnibus Motion but deferred the remaining requested waivers.

22. On December 31, 2024, through Decision No. C24-0956-I, the Commission directed Public Service to file Supplemental Direct Testimony addressing certain topics.

23. On January 22, 2025, the Commission, through Decision No. C.25-0049-I, vacated the prehearing conference.

[8] In addition to the parties established through this order, through Decision No. C25-0366-I, issued May 13, 2025, the Commission denied the *pro se* late intervention filed by Mr. David Thielen.

24. Through Decision C25-0064-I, issued January 29, 2025, the Commission established a procedural schedule, scheduled a remote evidentiary hearing, set procedures for the evidentiary hearing, and directed certain modifications to Staff's scope of work for the ITA. Through this same decision, the Commission also granted the Company's request to extend the deadline to file the previously ordered supplemental direct testimony.

25. Through Decision No. C25-0097-I, issued February 13, 2025, the Commission set a technical conference for March 20, 2025, later rescheduled to March 13, 2025,[9] to address certain models and forecasts Public Service put forth in both this Proceeding as well as the Company's Distribution System Plan.

26. Subsequently, through Decision No. C25-0147-I, issued February 28, 2025, the Commission clarified procedures and adopted an agenda for the technical conference.

27. Public Service, in response to Decision No. C24-0956-I, filed supplemental direct testimony on February 21, 2025.

28. The Commission held a remote technical conference on March 13, 2025, during which the following six categories of information were addressed: (1) electric vehicles ("EVs") and managed charging, (2) beneficial electrification ("BE"), (3) large new loads such as data centers, (4) the 8760 process for peak load forecasts and LoadSEER, (5) the long-term residential customer rate analysis, and (6) a miscellaneous category.[10]

29. On March 25, 2025, through Decision No. C25-0219-I, the Commission added two additional in-person public comment hearings and one remote public comment hearing to the procedural schedule. The public comment hearings were scheduled as follows: (1) an in-person

[9] The initial date for the technical conference was March 13, 2025. The Commission, through Decision C25-0147-I, issued February 28, 2025, granted the Company's request to reschedule the technical conference to March 20, 2025.

[10] The Commission directed the Company to address these categories in Decision No. C25-0168-I.

public comment hearing in Pueblo, Colorado on April 17, 2025; (2) a remote public comment hearing on April 28, 2025; and (3) an in-person public comment hearing in Hayden, Colorado on May 1, 2025.

30. On March 28, 2025, the Commission granted an unopposed motion for intervention out of time by Grid United, LLC ("Grid United") and Grid United became a party to this Proceeding.

31. Through Decision No. C25-0252-I, issued April 3, 2025, the Commission, among other things, granted an Unopposed Motion for Limited Participation filed by the Colorado Department of Public Health and Environment ("CDPHE") to provide a neutral verification review of the Company's Base Portfolio in Phase I and the preferred portfolio submitted in Phase II of this Proceeding. The Commission also clarified that the Phase II Verification Report should be filed 30 days after the Company's submission of its 120-day report.

32. Through Decision No. C25-0279-I, issued April 11, 2025, the Commission denied a motion to reschedule the Pueblo public comment hearing filed by the Environmental Justice Coalition, CRES/PSR. Also through Decision No. C25-0279-I, the Commission added another remote public comment hearing scheduled for June 5, 2025.

33. On April 2, 2025, Public Service filed Hearing Exhibit 115, which provided for the Strategic Reliability Reserve Fund concept. The Company stated this strategic reserve fund was designed to manage supply chain challenges and secure combustion turbines and transformers for the benefit of Colorado customers during the JTS RAP (which ends in 2031).

34. Parties filed Answer Testimony on April 18, 2025.

35. On May 2, 2025, through Decision No. C25-0343-I, the Commission granted, in part, a motion filed by CC4CA requesting that Public Service file supplemental testimony

explaining and supporting the strategic reserve fund proposal. The Commission extended discovery on the limited issue of the strategic reserve fund through the cross-answer testimony deadline of May 23, 2025, and identified specific questions for the Company to address in its supplemental direct.

36. The Company filed supplemental direct testimony regarding the strategic reserve fund on May 9, 2025.

37. Parties filed Rebuttal and Cross-Answer testimony on May 23, 2025.

38. Prior to the evidentiary hearing, in accordance with Decision Nos. C25-0279-I and C25-0219-I, the Commission held four public comment hearings: two were held in-person in the communities of Pueblo and Hayden, and two were conducted remotely.

39. A remote evidentiary hearing was held before the Commission *en banc* on the following dates: June 10-13, 17-18, 20, 23, and 24, 2025. At the start of the evidentiary hearing, the Commission admitted all pre-filed testimony and attachments into the evidentiary record as Hearing Exhibit 2800. During the course of the hearing, the Commission admitted the following hearing exhibits that were offered by parties during their cross-examination or re-direct of witnesses: Hearing Exhibits 112 JLB-1 rev. 1, 126, 127HC, 131, 132, 133, 134, 135, 137, 138, 140HC, 140 (public), 141 restricted HC, 141 (slip), 143, 302, 311 312, 314, 315, 403, 404, 406, 407, 408, 409, 410, 411, 413, 414, 700, 701, 700C, 700HC, 701HC, 700 Att. WAM-5, 700 Att. WAM-5C, 705, 710, 715, 717, 722, 805, 1002, 1306, 1307, 1308HC, 1310, 1403, 1403 Att. 4-1.A1, 1403 Att. 4-1.A2, 1403 Att. 4-1.A3, 2005, 2006, 2007, 2009, 2103, 2105, 2106, 2208, 2208 (executable), 2209, 2212, and 2608. In addition, the Commission took administrative notice of the following Hearing Exhibits: 405, 412, 415, 704, 707, 717, 1704, and 2210.

40. Through Decision No. C25-0514-I, issued July 11, 2025, the Commission extended the deadline for parties to file their Statements of Position ("SOPs") to July 17, 2025, and invited parties to include legal arguments and discussion in their SOPs addressing the impacts that the recently passed federal Reconciliation Bill may have on this Proceeding.

41. Parties filed SOPs on July 17, 2025.

42. On August 4, 2025, Moffat County and the City of Craig filed a motion to strike portions of Pueblo Intervenors' SOP. Through Decision C25-0581-I, issued August 7, 2025, the Commission set a shortened response time to the motion to strike, and Pueblo Intervenors filed a response on August 11, 2025.

43. The Commission deliberated at its August 6, 13, and 27, 2025 Commissioners' Weekly Meetings, as well as at Commissioners' Deliberations Meetings held on August 18 and 21, 2025, resulting in this Decision.

44. Finally, in addition to the evidence admitted during the evidentiary hearing, the administrative record for this Proceeding includes numerous written public comments from individuals, organizations, and elected officials.

D. Public Service's Proposed JTS

45. Given the ERP and CEP structures described above, Public Service's JTS seeks to identify and develop a framework to acquire sufficient resources to meet growing energy and capacity needs and provide new tools such as the CFFD proposal to identify carbon free dispatchable resources like advanced geothermal and nuclear that can provide service in a low- or zero-emission manner. Public Service lists several objectives for the JTS, including achieving an

80 percent emissions reduction by 2030, maintaining reliability in a load-growth environment, delivering a just transition, and improving Colorado's ERP process.[11]

46. Regarding just transition, Public Service's JTS reaffirms the community assistance framework in the 2021 ERP/CEP's USA in which Pueblo County would receive 10 years of payments and Routt County and Morgan County would receive six years of payments, with such payments being offset by any infrastructure investments in the communities. Public Service also offers to "facilitate discussions" with large new loads such as data centers to potentially site these loads in just transition communities.[12] In addition, Public Service seek Commission approval to hardwire certain changes to the Phase II modeling in an effort to drive additional investments in just transition communities. Specifically, the Company proposes to apply a modeling benefit, either in the form of a $/kW-month or a $/MWh, to projects in just transition communities. This modeling benefit would be in addition to the property tax tail/offset approach used in the 2021 ERP/CEP. Together, this would essentially make projects located Routt County, Morgan County, and Pueblo County look more economic for purposes of the Phase II modeling and increase the chance that such projects would be included in the approved portfolio of resources.[13]

47. As for the improvements to the ERP process, Public Service proposes several modifications for Phase II the Company asserts are necessary given current and future dynamics. For instance, the Company seeks approval of a conforming bid policy to make the bid evaluation and PPA negotiation process more efficient. In addition, the Company proposes to allow submission of pre-construction development asset bids that will supplement and serve as backups

[11] Hr. Ex. 101, Att. JWI-1, pp. 7-8.
[12] Hr. Ex. 101, Ihle Direct, Rev. 1, p. 52.
[13] Hr. Ex. 101, Ihle Direct, Rev. 1, pp. 47-48.

to the Commission's approved Phase II portfolio. The Company also asks that the Commission proactively decide to apply a 120-day timeline for CPCNs arising from the JTS.[14]

48. To meet the objectives of continued emissions reductions and maintaining reliability in an environment where load is increasing, Public Service requests the Commission be prepared to approve in Phase II a large resource portfolio. In particular, in its Direct Testimony, Public Service argued that it would need to acquire almost 14,000 MW of new resources in Phase II.[15] For context, the approved portfolio in the 2021 ERP/CEP, the largest in Colorado's history, was comprised of approximately 5,900 MW resources.[16] In addition emissions reductions and reliability benefits, Public Service argues that Phase II approval of a large resource portfolio will attract new economic development to Colorado. The Company asserts that meeting load growth the right way can bring long-term rate benefits to customers.[17]

49. In its Direct Testimony, the Company proposed acquiring this large portfolio of resources through one RFP with a RAP through 2031. As discussed below, however, Public Service significantly modified its approach in Rebuttal Testimony when it introduced the Phase II Framework. Among other things, the Phase II Framework contemplates a base RFP, a supplemental RFP, and an incremental need pool to quickly respond to changing conditions. The Company now argues that approval of the Phase II Framework is the "fundamental decision needed in this Phase I. . . ."[18]

[14] Hr. Ex. 101, Ihle Direct, Rev. 1, pp. 40-42.
[15] Hr. Ex. 101, Ihle Direct, Rev. 1, p. 10.
[16] Decision No. C24-0052, issued January 23, 2024, ¶ 92 in the 2021 ERP/CEP.
[17] Hr. Ex. 101, Ihle Direct, Rev. 1, p. 10.
[18] Public Service's SOP at p. 2.

E. Phase II Framework and Large Load Forecasts

1. Overview

a. Party Positions

50. Several factors led to the Company's estimate that it would need a large resource portfolio in Phase II, including the retirement of coal facilities within the JTS's RAP and projected load from both new EV charging and beneficial electrification. The single largest driver of the Company's projected load growth, however, was speculation on new large loads like data centers. More specifically, for its base load forecast in Direct Testimony, the Company calculated that new data centers were anticipated to account for 62 percent of the projected energy growth and 72 percent of the projected peak demand growth.[19]

51. In response to Intervenor concerns noting the speculative nature of this significant large load growth, costs to ratepayers, stresses on the system, and impacts on emission reduction goals, Public Service substantially modified its approach to Phase II in Rebuttal, and continued to tweak its proposed approach through the hearing as it reached agreement with Staff, CEO, and CIEA on a Phase II Framework.[20] Among other things, the Phase II Framework proposes significant modifications to the standard ERP Phase II process that add flexibility, including a base RFP that would target resources through 2031 and a supplemental RFP in mid-2027 that would target resources through 2033. In addition, the Phase II Framework proposes an incremental need pool consisting of paid backup bids. If a project from the approved portfolio fails or additional load materializes after the JTS Phase II Decision, the Company could activate projects from the incremental need pool in an expedited manner. The Phase II Framework includes a process and

[19] Hr. Ex. 101, Ihle Direct, pp. 28-29.
[20] The details of the Phase II Framework are set forth in Hr. Exs. 144 and 145.

set of next steps to advance additional transmission investment. Under the Phase II Framework, the Company also commits to use the large load commercial principles it set forth in Rebuttal and to make a large load tariff filing no later than January 31, 2026.[21]

52. Public Service characterizes this updated Phase II Framework as the "cornerstone" of the JTS.[22] Among other benefits, the Company states the Phase II Framework provides a dynamic approach to addressing large load additions, including the ability to self-adjust by procuring new resources through the incremental need pool and the supplemental RFP.[23] In this way, the Phase II Framework is proposed as a flexible process that ensures increases in realized large load can be accounted for through the next phase of these proceedings, while also recognizing the filing of subsequent ERP proceedings and ongoing CEP processes regarding near-term acquisitions can also address and make prudent regulatory steps forward regarding Colorado's resource needs.

53. The Phase II Framework assumes the use of the Company's updated base forecast. Compared to the base forecast, the primary difference in the updated base forecast is that the Company only includes large loads that have reached an 80 percent probability (*i.e.*, the data center is negotiating either an electric service agreement ("ESA") or interconnection agreement ("IA") with the Company). In its updated base forecast, the Company retains a group of non-data center prospective loads it categorizes as strategic economic development customers. The Company claims that most information regarding these strategic economic development customers is confidential but states that several have existing facilities in Colorado. While none of the strategic

[21] Hr. Ex. 144, JTS Phase II Framework Redline, p. 5.
[22] Public Service's SOP at p. 2.
[23] Public Service's SOP at p. 3.

economic development customers have reached an 80 percent probability, the Company asserts that the core impediment to negotiating and signing an ESA or IA is the lack of certainty in power.[24]

54. In Rebuttal Testimony, the Company acknowledges that large load customers present risks to existing customers that should be mitigated. In addition to its reduced updated load forecast, the Company asserts that it reduces risk to existing customers by adopting certain commercial principles in its negotiations with large load customers over 100 MW. These commercial principles include customer protections designed to ensure that large customers "have sufficient 'skin in the game' to avoid the risk of procuring generation for speculative new load or procuring load for customers that may move projects to different jurisdictions or disappear altogether."[25]

55. Despite the changes Public Service makes in Rebuttal Testimony such as the reduced updated load forecast and commercial protections, several parties continue to raise concerns that costs for existing customers could inappropriately increase to pay for resources procured to serve large load customers. For instance, WRA and SWEEP argue the record in this Proceeding shows service requests from large loads are uniquely speculative. They reference the fact that even during the pendency of this Proceeding several projected large load customers withdrew their interconnection requests. Moreover, WRA and SWEEP argue the current approach to cost allocation grossly underrepresents the system costs driven by new large loads and assert that residential rates could potentially increase by 50 percent by 2031.[26] WRA and SWEEP also assert that projected demand for large loads has the potential to significantly increase greenhouse gas emissions from Public Service's system, at the exact same time that the Company is seeking

[24] Hr. Ex. 117, Ihle Rebuttal, p. 33.
[25] Hr. Ex. 123, Bailey Rebuttal, p. 41.
[26] WRA's SOP at p. 7.

to decarbonize to meet state clean energy goals. WRA and SWEEP state that responding to speculative interconnection requests from large loads is fundamentally a risk allocation problem. The Company has not agreed to share that risk, and the Company's proposed approach with the commercial principles provides limited risk protection for ratepayers.[27]

56. Conservation Coalition raises similar concerns and states the fundamental problem with the Company's approach is that ratepayers would pay for additional generation resources for new large loads *before* the large loads contractually commit to any customer protections in the commercial principles.[28] Conservation Coalition notes the Company tries to downplay this risk by arguing that other large load customers will materialize if the current ones fail to commit, but during the evidentiary hearing the Company refused to commit to share the financial risk of any associated stranded assets.[29] Conservation Coalition asserts that if the Company and its shareholders are not willing to bear any of the downside risk of Public Service's own proposal, Public Service's ratepayers should not bear that risk either.

57. Conservation Coalition specifically argues that the Commission should exclude large load customers for the load forecast until they sign long-term contracts implementing customer protections. Conservation Coalition argues this would provide certainty to both the Company and new large loads because the Commission would be authorizing the Company to acquire additional resources once the large loads contractually commit to customer protections. Conservation Coalition states the Company has failed to articulate any legitimate concern with requiring large loads to commit to customer protections before Public Service procures additional generation to serve them.[30]

[27] WRA's SOP at p. 8.
[28] Conservation Coalition's SOP at p. 21
[29] Conservation Coalition's SOP at p. 22 (citing Hr. Tr. June 18, 2025, pp. 75-76).
[30] Conservation Coalition's SOP at p. 21.

58. CEC takes a similar position as Conservation Coalition, WRA, and SWEEP. This is particularly noteworthy given that CEC's members are all large industrial electric customers.[31] In its SOP, CEC argues for a conservative and flexible load forecast and for mitigating the risks of overinvestment. CEC argues the unprecedented uncertainty in the new large load forecast requires protective measures that ensure existing customers are not harmed by new large loads. One such protective measure CEC advances is the "fair notice" concept in which prospective large new loads are made aware that they will be moved to the future large load tariff. CEC acknowledges the Company's concerns with this concept but notes that a "fair notice" provision "should not be an insurmountable hurdle for new large customers who are willing and able to pay the appropriate share of their cost of service."[32]

59. UCA similarly argues throughout the Proceeding that the Commission must ensure that non-large load customers are neither harmed nor forced to incur higher rates due to new large loads.[33] UCA proposes several modifications to the Company's commercial principles to reduce the risk to non-large load customers.

60. On the other hand, the Business Coalition supports the Company's JTS, stressing that the Company must have sufficient resources to meet the expanding needs of existing customers. The Business Coalition acknowledges there is no guarantee that the proposed new loads will all come online as anticipated, but asserts that Denver and Colorado have historically experienced positive migration.[34] The Business Coalition further argues that even if the forecasted demand does not materialize precisely as scheduled, the additional capacity on the system could

[31] CEC's Motion to Intervene, p. 3.
[32] CEC's SOP at p. 14.
[33] UCA's SOP at p. 1.
[34] Business Coalition's SOP at p. 3.

then be available for other new customers to utilize without the attendant delays in planning, permitting and constructing new generation and transmission.[35]

b. Findings and Conclusions

61. We find persuasive the concerns raised by intervenors that uncommitted new large load customers could inappropriately and dramatically increase rates for existing customers while also increasing greenhouse gas emissions. At the same time, we recognize the benefits of having greater flexibility within a dynamic Phase II process and appreciate the Phase II Framework. We therefore modify which large loads can be included in the Company's initial load forecast, while at the same time and as discussed further in this Decision, allow a phased in approach through Phase II should additional load materialize.[36]

62. Particularly under the Company's Direct Testimony proposal, ratepayer funds would be used to procure massive amounts of new generation to serve new large loads like data centers before such loads sign an ESA or IA or agree to any of the customer protections within the commercial principles. Out of all the parties in this Proceeding, Public Service is in the best position to know the likelihood of the large loads actually connecting to its system and purchasing electricity, yet even in its more recent positions taken in this proceeding, the Company stated it is unwilling to share the financial risk of the large loads ultimately not materializing.[37] At the same time, this Commission finds compelling party responses that warn against placing the financial risk of large loads that may not materialize on existing Colorado customers. If WRA and SWEEP's

[35] Business Coalition's SOP at p. 4.

[36] While separately decided, this Decision is also considered in the context of years of electric resource planning process procurements in Colorado, ongoing CEP procurements, and in light of future ERP considerations that will also allow measured approaches to ensuring Colorado's resource needs are met. It is in this ecosystem of measured regulatory action that the Commission here continues a reasoned approach that avoids actions that could unreasonably burden ratepayers or emission targets, while providing a path forward for realized load increases in the short and long-term planning processes.

[37] Hr. Tr. June 18, 2025, pp. 75-76.

warning of 50 percent higher rates for existing residential and other customers comes to pass, it could jeopardize other State objectives, including increasing beneficial electrification ("BE"), promoting the adoption of electric vehicles ("EVs"), and continued economic development.

63. Rather than allowing Public Service to spend money acquiring resources as soon as a large load customer begins negotiating an ESA or IA, large load customers—including the largely confidential strategic economic development customers—must first contractually commit their load additions and the customer protections within the commercial principles as modified by this Commission before they can be included in the load forecast. The Company characterizes the commercial principles as ensuring that large customers "have sufficient 'skin in the game' to avoid the risk of procuring generation for speculative new load. . . ."[38] Public Service has failed to explain why the Company should be allowed to acquire through these ERP competitive bidding processes additional generation before large loads agree to put "skin in the game." A prudent path forward ensures these large loads will commit to Colorado in a way that equitably allocates the costs and benefits associated with serving their load, prior to including them in the load forecast. Overinclusion could risk burdening ratepayers for decades without cause. As discussed below, because we largely adopt the Phase II Framework, Public Service has opportunities through the incremental need pool and supplemental RFP to acquire additional resources in response changing circumstances, including additional large load customers contractually committing to customer protections. The incremental need pool is available after the JTS Phase II decision approving a resource portfolio from the base RFP, and the supplemental RFP is scheduled to issue in 2027. In 2028, the Company is set to file a new ERP application. These pathways in the Phase II

[38] Hr. Ex. 123, Bailey Rebuttal, p. 41.

Framework are in addition to other regulatory pathways the Company has, such as filing a standalone CPCN application for new resources, which it can do at any time.

64. The record in this Proceeding demonstrates how easily large customers can withdraw their interconnection requests even after negotiating an ESA or IA with the Company. Public Service acknowledges that during the period between the Company's Direct and Rebuttal Testimony filings, one of the Company's largest prospective large-load customers withdrew its interconnection request. This withdrawal and the corresponding impact to the load forecast occurred even though this customer was beyond simply negotiating an ESA or IA and had 90 percent probability.[39] Despite this and other evidence regarding the speculative nature of large load customers,[40] Public Service maintains its position that it should be allowed to procure additional generation as soon as a new large load begins negotiating an IA or ESA. We reject this approach and the unnecessary risks it would impose on existing customers.

65. Public Service argues it is in a "chicken and egg" situation regarding large loads in that many new large customers are eager to execute an IA and ESA with the Company, but both the Company and the large customers need certainty that the Company will be able to procure and supply the necessary generation before executing such agreements.[41] As set forth above, allowing the Company to procure a surplus of new generation to attract prospective large customers places an unacceptable amount of risk on the existing customers who will pay for the surplus generation. Nevertheless, by largely adopting the Phase II Framework's incremental need pool and supplemental RFP, our Decision provides greater regulatory certainty to prospective large

[39] Hr. Ex. 123, Bailey Rebuttal, p. 13.

[40] *See e.g.*, Hr. Ex. 1301, Eiden Answer, p. 30; Hr. Ex. 303, Sommer Answer, pp. 8-9; Hr. Ex. 123, Bailey Rebuttal, p. 21 (acknowledging concerns regarding "forum shopping" "where a single project engages with multiple utilities, waiting to see which it is able to procure power from most expeditiously.").

[41] Hr. Ex. 123, Bailey Rebuttal, pp. 10-11.

customers and Public Service so that the Company will be able to swiftly acquire additional generation.

66. To be clear, this Commission is not disregarding arguments and testimony that having sufficient generation resources necessary to serve new large customers may provide economic benefits to the State.[42] In no way are we preventing Public Service from acquiring generation to serve new large loads. Rather, our Decision is aimed at resolving what WRA and SWEEP characterize as a risk allocation problem. Existing customers should not be required to bear higher electricity rates if large loads withdraw their interconnection requests, nor should existing customers be required to subsidize the cost of serving new large loads. If a large customer contractually commits to the commercial principles, our approach provides both the large customer and Public Service the regulatory certainty it needs to swiftly procure additional generation. If new large customers are ready to commit quickly and with fair warning that they may be subject to the new Commission-approved rate, if applicable, then their prospective loads can be included in the updated load forecast that the base RFP will seek to meet. If large customers need additional time, our approvals of the incremental need pool and supplemental RFP (discussed more below) provide another pathway for the Company to quickly procure additional resources. The regulatory mechanisms we approve through this Decision, including the incremental need pool, the supplemental RFP, and the strategic resilience reserve fund, provide unprecedented speed and flexibility compared to our typical ERP processes.

67. Thus, consistent with CEC's arguments, we are approving an initial load forecast now while at the same time providing regulatory flexibility that will quickly permit additional

[42] *See, e.g.*, Hr. Ex. 123, Bailey Rebuttal, p. 19; Public Service's SOP at pp. 14-15; Business Coalition's SOP at pp. 3-4.

generation once there is sufficient assurance that existing customers will not solely bear the well-established risk associated with new large loads. The Commission is eager to support Public Service in acquiring new generation it needs to reliably serve existing customers and new large load customers that are willing to commit to Colorado. We are unwilling to make existing customers commit to pay for additional generation before large loads sign a binding ESA and IA at a rate that equitably allocates the costs and benefits.

68. Thus, to be included in the load forecast,[43] large customers must execute both an IA and an ESA. At a minimum, the ESA must contain the commercial principles (as modified below) as well as an express "fair notice" provision informing individual customers that a future large load tariff will be fully litigated in a subsequent proceeding and that this new rate may apply instead of the existing tariff. As Staff, WRA, and SWEEP observe, no customer is immune from Commission-approved changes in tariffs.[44] Contrary to the Company's position, tariffs are subject to change over time and customers may be migrated to different tariffs or rate classes depending on their load characteristics and the terms and conditions under which they take service. Moreover, the fair notice concept is critical to ensure that existing customers do not inappropriately subsidize the cost of serving new large load customers and—as CEC notes—is not "an insurmountable hurdle for new large customers who are willing and able to pay the appropriate share of their cost of service."[45]

[43] As referenced above, if a large customer meets the requirements quickly enough to be included in the Company's updated load forecast that it will file prior to the issuance of the RFP, the large customer's associated load will be incorporated into the base RFP. Large customers that meet the requirements after the updated load forecast can serve as the basis for activation of the incremental need pool or be included in the load forecast the Company will use for the supplemental RFP. We note, however, that the Commission may modify these requirements during the course of the large load tariff filing.

[44] Staff's SOP at p. 10; WRA and SWEEP's SOP at pp. 9-10.

[45] CEC's SOP at p. 14.

69. We reject the Company's position that 100 MW should be the size threshold above which these additional protections take effect. On this point, we note that Conservation Coalition argued the threshold should be 50 MW; UCA proposed 75 MW but notes that the Ohio Commission recently approved a limit of 25 MW; and WRA and SWEEP simply argue the commercial principles should be applied to all large load customers. Weighing these various positions, we find that 50 MW strikes the appropriate balance of protecting existing ratepayers while not overly burdening new customers that, while still sizable, are significantly smaller than some of the other anticipated loads. This 50 MW demand threshold applies to a load's projected peak demand over the RAP, as measured across all meters billed to the same entity. The 50 MW threshold applies to all customers, regardless of whether the customer connects to the transmission or distribution system or whether the Company has identified the customer as a strategic economic development customer.

70. For customers smaller than 50 MW that the Company wants to add to the load forecast to support the acquisition of new generation, Public Service must have completed a facility study, begun relevant negotiations, and have executed either an IA or an ESA (or an equivalent contract if the load is connected at the distribution level). However, we generally leave the form and duration of such contracts to the Company's discretion. While the relevant contract for customers smaller than 50 MW need not include the commercial principles, the contract must still include the fair notice provision if the customer is 20 MW or larger. The fair notice concept is not necessary for customers under 20 MW, but consistent with current practice the Commission makes no guarantee that the tariff class for customers under 20 MW will remain unchanged.

71. We note that loads associated with oil and gas electrification will likely be under the 50 MW threshold. The low load forecast assumes 151 MW for oil and gas electrification, which

appears largely unopposed. Thus, as Public Service signs new oil and gas customer contracts and satisfies the other requirements set forth above, both the base and supplemental RFP load forecasts and associated resource acquisitions would be expanded for the new load above the 151 MW already in the low load forecast. Assuming these new oil and gas loads are under the 50 MW threshold, the contracts need not contain the commercial principles.

2. Commercial Principles

a. Party Positions

72. As referenced above, in Rebuttal Public Service proposes a set of commercial principles, which the Company asserts ensure reasonable customer protections by requiring large customers to have sufficient "skin in the game."[46] These commercial principles consist of the following nine components: (1) up-front study deposit, (2) minimum bill, (3) minimum contract term, (4) load threshold/applicability, (5) security, (6) facilities costs, (7) exit fee, (8) assignment, and (9) load flexibility/renewable programs. More specifically, there would be a $250,000 non-refundable up-front study deposit at the time the customer submits an interconnection request.[47] The Company may adjust this upward if needed. The customer's minimum bill would be 75 percent of the projected needs the customer listed in its ramp schedule, and there would be a minimum contract term of 15 years. The load threshold would be 100 MW of new or expanded load.

73. For security, the large customer would be required to provide a letter of credit ("LOC") or cash deposit in conjunction with the signing/effective date of the IA, with process and conditions generally aligned with Company's existing large customer credit/deposit requirements

[46] Hr. Ex. 123, Bailey Rebuttal, p. 41.
[47] Hr. Ex. 123, Bailey Rebuttal, p. 40.

and OATT Schedule Q credit policy: First, the applicant will submit a load ramp in conjunction with Interconnection Request, to contain peak load. Second, the Company will require security through cash or irrevocable standby LOC, which shall be the equivalent of three months (90 days) of estimated bills based on the peak load included in the customer's load ramp schedule. The security shall be posted for at least 36 months after the customer starts taking service, renew annually, and after 36 months, subject to the Company's agreement, it may convert to a parental guarantee with security to remain in place for the duration of the contract. Third, all security will be posted in conjunction with the effective date of the customer's IA. And fourth, the Company will conduct a credit evaluation of each counterparty upon submission of an Interconnection Request, and again prior to executing an IA.[48]

74. Regarding the remaining commercial principle components, the Company will require up-front facilities payment from the customer for all direct assigned facilities, consistent with the Company's current distribution and transmission interconnection policies. In addition, if a customer terminates service prior to the end of the 15-year term, an exit fee shall be assessed equivalent to 75 percent of a customer's needs under customer load ramp schedule for remainder of 15-year term. However, the Company will make commercially reasonable efforts to mitigate and may reduce the exit fee if it can readily serve other customers or sell the excess energy/capacity. The customer cannot assign or transfer ESA/IA absent express Company approval and transferee/assignee meeting the requisite credit metrics. Finally, the Company will encourage all new large load customers to provide load flexibility, including 80-100 hours of interruptible load shed during the year.[49] The Company may consider future filings to adapt its

[48] Hr. Ex. 123, Bailey Rebuttal, p. 40.
[49] Hr. Ex. 123, Bailey Rebuttal, p. 41.

interruptible rate program for new large customers as the Company gains more experience transacting with large load customers during the interim period. Public Service will market its voluntary renewable and DSM programs to all new large load customers.

75. While Public Service asks the Commission to approve these commercial principles as part of its large load strategy, the Company argues that flexibility and the ability to negotiate are important. The Company states there may be circumstances where deviating from the commercial principles is warranted.

b. Findings and Conclusions

76. We appreciate Public Service proposing these commercial principles and generally adopt them as appropriate concepts for inclusion to protect customers, but we find certain modifications are necessary to ensure the proper risk allocation regarding new large customers, existing customers, and the Company. In addition, we emphasize that these principles will be fully litigated in the large load tariff filing expected in January 2026.

77. First, in addition to the requirement that the fair notice concept be included in the commercial principles, the ESA must specifically include the credit support and exit fee concepts. Also, we adopt UCA's suggestion and increase the security commitment to six months of anticipated bills, as opposed to the Company's proposal for just three months.[50] Finally, as part of the large load tariff filing, Public Service shall file a detailed Colorado-specific IA and ESA, and each contract must be consistent with the modified commercial principles we adopt here and clearly lay out the security and exit fee provisions. We anticipate the Commission will further

[50] Hr. Ex. 308, UCA Surrebuttal Comments, p. 5. UCA also proposes that large customers should be required to contribute to tariffs such as the ECA. Although we intend to examine this issue during the large load tariff filing, at this time we refrain from modifying the applicable tariffs. Whatever existing tariff the large customer takes service under, that tariff will control the applicable riders to which the customer must contribute.

refine the commercial principles and other requirements for new large customers through the course of the large load tariff filing.

78. The Company retains discretion to negotiate the applicable agreements as it deems necessary, including the commercial principles. It is our expectation, however, that the customer protections, including the "fair notice" provisions, within the commercial principles will remain. Indeed, the Company's presumption of prudence is contingent on the customer protections being in place. If Public Service negotiates away these approved commercial principles and a large customer does not materialize as expected, Public Service may share the risk associated with the shortfall in expected revenues. In this way, particularly prior to the large load tariff being litigated and approved, the Company retains its discretion in negotiations, but the expectation of customer protections remains constant, appropriately ensuring that the balance and risk of negotiating these concepts further remain on the Company.

3. Large Load tariff Filing

79. As referenced above, as part of the Phase II Framework Public Service commits to make a large load tariff filing no later than January 31, 2026. Some of the primary objectives of this tariff filing includes evaluating cost allocation, establishing terms and conditions of service, and developing a specific rate structure for large load customers.[51] This addition appears responsive to Answer Testimony from UCA, Conservation Coalition, WRA, and SWEEP and the general concept is unopposed.

80. While Conservation Coalition, WRA, and SWEEP support a large load tariff filing, they suggest the Commission should also use this filing to evaluate a clean transition tariff. At a high level, the clean transition tariff should allow large customers to voluntarily pay to be

[51] Staff's SOP at p. 6.

served by innovative, zero-emission resources that public service would not otherwise procure. Conservation Coalition argues that one of the benefits of a clean transition tariff is that it provides a mechanism to develop innovative, zero-emitting resources that may not otherwise be cost-effective to procure as system resources. Conservation Coalition asserts that many companies that are developing large data centers have corporate clean energy goals and may pay a premium for clean electricity.[52]

81. Consistent with its commitment under the Phase II Framework, we direct Public Service to make a large load tariff filing no later than January 31, 2026.[53] This future proceeding will provide the appropriate forum to address cost allocation approaches for large loads including ensuring that this new tariff reflects the actual incremental costs and benefits of serving these new loads in ways that account for differences in load flexibility during critical peak demand periods and locational impact. For example, a new large load customer located outside the transmission-constrained Denver metro area that can flexibly reduce demand during the most at-risk peak demand hours at the Company's request should perhaps have access to a lower rate that reflects the reduced costs that this customer imposes on the system.

82. In contrast, large new load customers that locate in the transmission-constrained Denver metro area and are unable to adjust usage during critical peak demand periods should perhaps pay a higher rate that reflects that customer's pro-rata share of the full incremental generation and transmission costs required to serve growing load as quantified in this resource planning process.[54] As such, the Company is hereby ordered to file in its direct case in the January 2026 advice letter filing separate rate options for the parties to consider that provide appropriate

[52] Conservation Coalition's SOP at pp. 22-23.
[53] Hr. Ex. 144, JTS Phase II Framework Redline, p. 5.
[54] *See, e.g.*, HE 133, Executable Attachment, JWI-5, Rev Req Sheet (summing up the entered Capex on lines 5 through 19 in ways that define the cumulative generation and transmission cost associated with load growth).

large new load customer incentives based on the costs they impose on the system depending on their ability to flexibility reduce load or whether they can locate outside the transmission constrained Denver metro area. Given the size of these potential new customers, the Commission is concerned that the existing demand response or interruptible service approaches will not provide proper incentives and would like to comprehensively explore the options in the advice letter filing.

83. Although the resulting tariff from this future proceeding will likely not be adopted until late 2026, we reemphasize that—consistent with the fair notice concept—the new large load tariff may apply to customers that take service prior to the tariff's adoption. In other words, tariffs and tariff classes are subject to change.

84. In conjunction with its large load tariff filing, Public Service shall also submit its proposal for a clean transition tariff, consistent with recommendations from WRA, SWEEP, and Conservation Coalition.[55] We find the arguments from these parties persuasive and are intrigued by another potential avenue to allow large customers to quickly secure necessary generation resources, especially resources that aid rather than hinder the State's greenhouse gas emissions targets.

85. We also require Public Service in the large load tariff filing to respond to the load volatility concerns UCA raises regarding large loads like data centers. UCA asserts that large loads suddenly disconnecting or reconnecting to the grid could cause regulation violations or transient instability. UCA also asserts that large loads affect ramping needs, reactive power requirements, and reserve margins.[56] We find UCA's concerns to be legitimate. If large loads like data centers present specific risks to the larger system, the costs associated with mitigating those risks should

[55] WRA and SWEEP's SOP at p. 11; Conservation Coalition's SOP at pp. 22-23.
[56] Hr. Ex. 304, Milligan Answer, pp. 28-29.

be borne by those large loads. This is particularly a concern given the Company's focus on a seemingly smaller ramp potential associated with solar generation near Pueblo.[57] Thus, Public Service shall expressly respond to the following concerns UCA raised regarding with large loads: (1) load ramping, variability, and uncertainty; (2) load cycling and oscillation risks; (3) load ride-through performance; (4) power quality and harmonic emissions; (5) sub-synchronous oscillation risks; and (6) impacts on utility protection systems.[58]

86. Finally, the Commission clarifies that, moving forward, any new large load customer cannot take service under an Economic Development Rate. WRA and SWEEP note that the Company does not object to such a restriction.[59]

4. Phase II Framework's Incremental Need Pool

a. Party Positions

87. One of the foundational components of the Phase II Framework is the incremental need pool because it allows for the additional acquisition of resources in between the base RFP and the supplemental RFP. As proposed, the incremental need pool could also be used following the supplemental RFP. Any project included in a Phase II portfolio or identified through the backup bid modeling process can elect to be incremental need pool. Each project electing to be considered for the incremental need pool would provide in its bid a $/MW/year payment amount needed for it to follow the terms of the incremental need pool process, up to an annual cap of the lesser of $3 million or $10,000/MW/year per bid.[60] The Company will propose a portfolio of incremental need pool projects in the 120-Day Report for Commission approval. Once approved, an

[57] *See* Hr. Ex. 102, Landrum Direct, pp. 45-46.
[58] Hr. Ex. 303, Sommer Answer, pp. 20-21.
[59] WRA and SWEEP's SOP at p. 21 (citing Hr. Tr., June 11, 2025, p. 169).
[60] Hr. Ex. 144, JTS Phase II Framework Redline, p. 4.

incremental need pool project must remain exclusive to Public Service for not less than one year, up to a two-year term.

88. If an activation call for that bid occurs, the project would need to abide by the incremental need pool process. All participating projects in the incremental need pool could provide a price refresh within 21 days, subject to a 10 percent cap on the total project cost or PPA rate. Public Service would evaluate the refreshed prices, retaining competitive tension in the process.[61]

89. The incremental need pool activation process can be triggered by either an approved project failing or a new large load reaching the designated criteria. Under the Proposed Phase II Framework, this designated criteria is either the negotiation of an ESA and IA (*i.e.*, Step 8) for loads less than 100 MW or a signed IA or ESA (*i.e.*, Step 9) for loads of 100 MW or more. Upon one of these triggering events, the Company notifies the Commission of the incremental need pool activation and provides a brief alternatives analysis and an updated loads and resources table. This notice will include the results of the price refreshes and the Company's proposed incremental need pool projects to activate. The precise activation process then depends on whether the incremental need pool was triggered by a project failure, a large load and, if a large load, the relative size.[62]

90. In Rebuttal, Public Service explains that if a bid in the approved portfolio fails, the Company will follow a like-for-like process in which it will attempt to find a replacement project with the same ownership and technology type.[63]

[61] Hr. Ex. 144, JTS Phase II Framework Redline, p. 4.
[62] Hr. Ex. 144, JTS Phase II Framework Redline, pp. 4-5.
[63] Hr. Ex. 118, Landrum Rebuttal, p. 13.

91. Public Service, Staff, CIEA, and CEO all support the incremental need pool concept and ask the Commission to approve it without modification.

92. UCA raises concerns with several elements of the incremental need pool process. UCA argues the option payments would lock in the incremental need pool projects exclusively with Public Service. UCA warns this structure may favor incumbent developers or legacy projects, reduce competition, and limit the ability to react to fast-changing market conditions or new technologies. UCA recommends the Commission build in steps to ensure public review of price updates, potential market manipulation, and emissions impacts.[64] UCA also argues there is no performance security or fallback plans for failed bids or delayed projects. UCA recommends the Commission require the Company to require clear accountability metrics, milestone tracking, and strong financial penalties for failed bids included in the resource portfolio or incremental need pool.[65]

93. CEI generally supports the incremental need pool concept but raises concerns the 10 precent price refresh opportunity may not be sufficient. CEI recommends removing any cap on price refreshes, particularly for bids that may have incorporated ITC/PTC tax credits.[66]

94. WRA and SWEEP raise several issues with the incremental need pool as proposed. First, they argue that without strict and enforceable emissions limits, any new thermal resources acquired solely to meet the needs of a new large customer could produce significant levels of greenhouse gas emissions. WRA and SWEEP therefore argue the Commission should require updated emissions verification workbook regardless of the size of load, and the Company should be required to demonstrate that any portfolio of bids activated under the incremental need pool

[64] UCA's SOP at pp. 13-14.
[65] UCA's SOP at p. 14.
[66] CEI's SOP at p. 26.

will meet or exceed the emissions trajectory approved in the Phase II decision. WRA and SWEEP also argue that when the incremental need pool is activated to replace a failed bid, the Commission should require a similar size and technology replacement project to ensure that emission impacts are avoided.[67]

95. In addition, WRA and SWEEP recommend that only loads that reach 90 percent probability and have committed to contractual protections determined through the large load tariff should be eligible to trigger the incremental need pool process. More fundamentally, WRA and SWEEP assert the incremental need pool process should not be used until the large load tariff is in place.[68]

96. Similar to WRA and SWEEP, Conservation Coalition argues the Commission should reject procuring resources through the incremental need pool for large customers that have not yet signed a long-term contract implementing all of the commercial principles and that the Company should be required to provide verification workbooks showing compliance with CEP emission-reduction requirements. In addition, Conservation Coalition asks that in each activation of the incremental need pool, the Commission require Public Service to present at least two alternative resources or portfolios that are the cheapest alternatives to the resources the Company seeks to procure. Conservation Coalition argues the Company's proposal to present only its proposed resources may leave stakeholders and the Commission with no way to meaningfully evaluate the alternatives and no understanding of why the Company proposed one set of resources over others.[69]

[67] WRA and SWEEP's SOP at pp. 19-20.
[68] WRA and SWEEP's SOP at p. 20.
[69] Conservation Coalition's SOP at p. 24.

97. Although CC4CA does not seem to oppose the broader Phase II Framework, CC4CA raises emissions and cost concerns regarding the incremental need pool portion. Regarding emissions, CC4CA argues the Commission should direct the Company to file an emissions verification workbook for all activated incremental need pool resources (except for like-for-like resources activated due to failed bids from an approved portfolio) and only allow additional resources via the incremental need pool if the emissions impact of those resources maintain at least the emissions reduction pathway of 80 percent by 2030 and 100 percent by 2050. Further, in selecting resources activated in the incremental need pool, CC4CA argues the Company should seek to maintain the emissions trajectory of the approved portfolio in Phase II.[70]

98. Regarding ratepayer protections, CC4CA reiterates concerns raised by WRA, SWEEP, and Conservation Coalition regarding potentially overbuilding for large new loads that fail to materialize. For instance, CC4CA argues the Commission should ensure that long-term contracts include consumer protection guardrails before large loads are included in the assumptions underlying resource solicitations. CC4CA also raises concerns about the option payments that the backup bids in the incremental need pool would receive. CC4CA opposes the idea that ratepayers could end up on the hook for up to $3 million per bid in the incremental need pool, while the large customers that trigger the activation of incremental need pool bids would not contribute to such payments. CC4CA suggests the Commission direct the Company to recover the total "option payment" costs of the incremental need pool from ratepayers and large new loads in a manner proportional to the resources activated on a load basis due to failed bids from the approved portfolio and due to demand from large new loads, respectively.[71]

[70] CC4CA's SOP at pp. 9-10.
[71] CC4CA's SOP at pp. 10-11.

99. Walmart argues that the incremental need pool is unnecessary and should be rejected. Walmart notes that with the base RFP, supplemental RFP, and the next full ERP in 2028, there will be three fully competitive RFPs over an approximately three-year period. According to Walmart, these three RFP renders unnecessary the need for the inferior incremental need pool process. Walmart asserts the incremental need pool is comprised of second-rate projects that were not selected during the immediately preceding RFP and that the Company will pay option payments to keep such bids "warm." The resources selected through the incremental need pool will, according to Walmart, not only be inferior but will also come at a cost to customers. Walmart argues that the only risk mitigated by the incremental need pool that is not already mitigated by having three fully competitive RFPs is the risk to the Company's shareholders. [72]

100. In the alternative, if the Commission does not agree to reject the incremental need pool, Walmart argues the Commission should not allow Public Service to move the option payment costs into rates when the corresponding incremental need pool project is not used and useful and may never be placed in service. Walmart asserts that approving recovery of the option payment costs would set a dangerous precedent. Walmart reasons the option payment costs for each incremental need pool project should be recorded to a deferred account, and Public Service can request to recover the option payment costs for only those projects ultimately placed into service for the benefit of customers.[73]

b. Findings and Conclusions

101. As referenced above, we generally support the incremental need pool concept and agree with Public Service, Staff, CEO, CIEA, and others that it will add useful flexibility to the

[72] Walmart's SOP at pp. 7-8.
[73] Walmart's SOP at pp. 8-10.

ERP process. Given the dynamic and uncertain environment developers are in, as well as the possibility for rapid load growth, the incremental need pool presents a reasonable process that allows the Company to swiftly respond to changing conditions. However, consistent with our above discussion and similar to the positions of parties like WRA, SWEEP, and Conservation Coalition, we modify the criteria for when the incremental need pool can be activated to serve a new large customer. Specifically, to be included in the load forecast justifying activation of the incremental need pool, large customers must execute both an IA and an ESA, and the ESA must contain the modified commercial principles, including the fair notice concept.[74] Just as we are unwilling to allow uncommitted large loads into the initial load forecast for the base RFP, we are unwilling to allow uncommitted large loads from triggering the incremental need pool. Nevertheless, this optionality allows both certainty and flexibility by including committed large loads at each incremental step.

102. Aside from this important modification, however, we reject the other intervenor requests. Regarding the various requests for increased emissions reporting, we find the incremental need pool as proposed already contains reasonable protections. For instance, Public Service will provide an updated emissions verification workbook for large customers greater than 100 MW. Even for large customers equal to or less than 100 MW, the incremental need pool "will seek to maintain system emissions performance…" and intervenors have the opportunity to submit comments prior to a Commission decision. This approach appropriately balances the need remain cognizant of emissions impacts while ensuring a quick and flexible process for acquiring additional resources.

[74] During the large load tariff filing, we intend to evaluate whether different criteria should be used once the new tariff is implemented.

103. Similarly, we find the current 10 percent cap on price refreshes to be reasonable and reject CEI's recommendation to eliminate the cap. The 10 percent cap appropriately balances the need for backup bids to have price flexibility to prevent them from going stale while also keeping the incremental need pool projects reasonably close to their initial bid. CC4CA's suggestion that large new loads should be required to pay relevant option payments, while intriguing, would be difficult to implement fairly at this stage. However, we would be open to exploring this concept further in the large load tariff filing.

104. We also reject UCA's requests to add more process to the incremental need pool, including milestone tracking and financial penalties for failed bids. Public Service already specifies in Rebuttal Testimony that an incremental need pool project that is unable to respond timely if called upon must return its option payments, with interest. Beyond these protections, we are wary of adding unnecessary process or trying to establish a milestone payment schedule on this record. For similar reasons, we reject Conservation Coalition's request for an analysis of alternative portfolios.

105. We likewise oppose Walmart's recommendation to eliminate the incremental need pool and Walmart's alternative recommendation to only allow the Company to recover option payments after the associated project is used and useful. While the option payments are a material cost, they help ensure that there will be a sufficient number of backup bids such that there will be competitive tension when the projects are asked to refresh. This competitive tension could result in considerable savings over the long term.

106. Finally, in keeping with the approved backup replacement process in the 2021 ERP/CEP, we modify the Company's proposal to use a like-for-like replacement process for ownership types. Given the misaligned incentives and potential for gaming, any time

Public Service wishes to activate a Company-owned backup bid, the Company must perform an alternatives analysis demonstrating why the utility-owned bid is the most appropriate option. Any time the Company proposes to activate a utility-owned bid, intervenors will have 45 days to file comments, the Company will have 10 days after intervenor comments to file reply comments, and the Commission will aim to issue a decision 45 days after the reply comments.

5. Additional Components of the Phase II Framework

a. Party Positions

107. As proposed, the Phase II Framework proposes that the base RFP would issue in 2026 and would have a RAP through 2031; the supplemental RFP would issue in mid-2027 and would have a RAP of through 2033; and the deadline for the next ERP would be extended to no later than December 31, 2028.[75] In addition, the modeling assumptions and other requirements for both the base RFP and the supplemental RFP would be set in this Decision. Public Service emphasizes that there would not be another Phase I decision prior to the supplemental RFP, although there would still be the typical Phase II process and decision addressing the proposed portfolio of resources from the supplemental RFP. The same portfolios that are used to showcase the results of the base JTS would also be used in the supplemental RFP.[76]

108. Public Service explains the primary differences between the load forecasts used in the two RFPs is that the load forecast in the supplemental RFP would account for contracted resources acquired from the base RFP and allows for bidding into new transmission investment. The supplemental RFP is essentially an "updated" updated base forecast that can adjust to changes in large new loads and any bid failures from the base RFP, time permitting. The Company states

[75] Hr. Ex. 144, JTS Phase II Framework Redline, pp. 1-2.
[76] Hr. Ex. 117, Ihle Rebuttal, p. 36.

it will update the subcomponents of the forecast based on the latest available information, including Clean Heat Plan electrification, EVs, and oil and gas electrification, and large load projections.[77]

109. Staff, CEO, and CIEA all support the Phase II Framework and argue the Commission should adopt it without modification. These parties generally argue the Phase II Framework provides needed flexibility yet reduces the risk of overbuilding by providing several avenues to procure incremental resources as load growth develops.

110. UCA requests certain modifications to the Phase II Framework. First, UCA asks the Commission to allow for a review and comment process for the forecasts modeled after the Phase I decision but before the RFP. Because of concerns raised by the federal Reconciliation Bill, however, UCA does not ask that the process be delayed by a review and comment period. Instead, UCA requests that a timeline be designed that accommodates input and allows processes to occur simultaneously.[78]

111. Interwest broadly supports the Phase II Framework and argues the 50 percent utility ownership target for the base RFP must also apply for the supplemental RFP. Interwest asserts extending the 50 percent ownership target helps ensure that Colorado's robust, competitive landscape for energy project development continues.[79] In contrast, Conservation Coalition argues against using the 50 percent ownership target for the supplemental RFP. Conservation Coalition asserts there is no testimony in the record offering any policy rationale to use the 50 percent ownership target (or any other ownership targets) for the supplemental RFP. Instead, Conservation Coalition argues each portfolio for the supplemental RFP should include the least-cost resources

[77] Hr. Ex. 118, Landrum Rebuttal, p. 11.
[78] UCA's SOP at pp. 11-12.
[79] Interwest's SOP at p. 13.

(subject to the constraints for that portfolio) without any explicit Company-ownership constraint in the model.[80]

112. Grid United, the developer of the Three Corners Connector, an 1,800-MW HVDC interregional line designed to connect Public Service's system in Pueblo to the SPP system in Oklahoma, argues the Commission should approve the proposed Phase II JTS Framework with the extended RAP through 2033. Grid United further requests the Commission expressly direct Public Service to evaluate non-generation capacity solutions, including interregional HVDC transmission projects that can come online before the end of the RAP.[81] Grid United asserts it is "undisputed" that interregional transmission projects like HVDC lines can provide substantial capacity value and customer savings.[82]

113. As referenced above, WRA and SWEEP recommend several changes regarding the large customers that can be included in the load forecast for both the base RFP and supplemental RFP. WRA and SWEEP also recommend the Commission require additional process before the supplemental RFP. They note that, as currently proposed, the supplemental RFP would only provide the same, brief comment process currently used in Phase II, despite the likelihood of significant changes to the Company's load forecast between the Phase I decision and the supplemental RFP. WRA and SWEEP recommend the Commission require the Company to provide its updated load forecast at least three months prior to the supplemental RFP, consider mechanisms to allow limited discovery on updates to the forecast, and retain the flexibility to institute additional procedures in the time leading up to the supplemental RFP.[83]

[80] Conservation Coalition's SOP at pp. 9-10.
[81] Grid United's SOP at p. 7.
[82] Grid United's SOP at p. 5.
[83] WRA and SWEEP's SOP at p. 22.

b. Findings and Conclusions

114. Consistent with the wide support from parties, we approve the basic structure of the Phase II Framework, including the timing and proposed RAPs for the base RFP and supplemental RFP, and the extended deadline for Public Service's next ERP. While novel, the Phase II Framework allows for a more nimble, flexible approach to acquiring resources in a dynamic and uncertain environment. The Commission will, in effect, be enabling resource need pools to move forward with forecasting in 2026 and 2027, with updates for the next ERP expected in 2028. These regular and iterative update opportunities presented by the parties allow the regulatory process to be responsive in coming years especially, despite uncertainty in the near term. Splitting the Phase II process as proposed in the Phase II Framework allows quick reactions in these next critical years and months especially.

115. At the same time and without expanding the process to instigate delay, we agree with WRA and SWEEP that there should be an opportunity for some additional process prior to the supplemental RFP. As these parties note, there will likely be significant changes to the inputs and assumptions used for the load forecast underlying the supplemental RFP, but there will be no Phase I process in which these changes can be evaluated. This is particularly concerning given our skepticism of the load forecast the Company endorses for the initial base RFP, and desire to be flexible if those loads materialize.

116. Thus, Public Service shall file its updated load forecasts it proposes to use for the supplemental RFP and the underlying models used to calculate such forecasts at least three months prior to the planned release of the supplemental RFP. As part of its filing, the Company shall propose a technical conference date that is within two weeks of the filing of the supplemental load forecast. The purpose of the technical conference will be to allow the Commission to quickly

understand more of the nuances of the supplemental load forecast, given the abbreviated schedule prior to the supplemental RFP. After the technical conference, intervenors will have one month to continue conducting discovery and submit comments. The deadline for Public Service to file response comments is two weeks after the intervenor comments. The Commission would then target a decision on the Company's proposed load forecasts within one month after the Company's response comments. If the Commission rejects the Company's supplemental load forecasts, the Commission would establish additional processes that would be required prior to the release of the supplemental RFP.

117. The technical conference and opportunity for comments will allow the Commission and parties to better understand the load forecast underlying the supplemental RFP. This will increase confidence that the results of the supplemental RFP are grounded in reasonable assumptions. If the Commission has no major concerns with the supplemental load forecast, the supplemental RFP will still be able to issue in an abbreviated timeframe.

118. While we agree with WRA and SWEEP regarding the need for additional process prior to the supplemental RFP, we reject UCA's request for additional process prior to the base RFP. Although UCA asks the Commission for more process prior to the RFP, UCA also maintains that such process should not delay the Phase II process. UCA does not offer a detailed explanation as to how the Commission could mandate a meaningful review and comment process that would not require additional time. Moreover, unlike what will likely occur with the supplemental RFP, parties have already had an extensive process to adjudicate the assumptions that will be used in the base RFP. If UCA has significant concerns after the Company files its updated forecasts prior to the base RFP, UCA always has the ability to file any appropriate motion as necessary.

119. As for the utility ownership target for the supplemental RFP, we agree with Conservation Coalition and will not adopt a formal 50 percent ownership target. In the supplemental RFP, the Commission can continue to weigh a balanced ownership percentage as one factor in establishing an appropriate portfolio. Ultimately, the most appropriate resource portfolio may have more or less than 50 percent utility ownership.

120. For the reasons set forth in its SOP and testimony, we grant Grid United's request and expressly direct Public Service to evaluate non-generation capacity solutions, including interregional HVDC transmission projects that can come online before the end of the RAP. For purposes of the supplemental RFP, Public Service shall consider the impacts of any interregional HVDC transmission, including the 1,800 MW HVDC Three Corners Connector, that can come online before the end of 2033. The Company must explain these considerations when it files the updated load forecasts that it plans to use for the supplemental RFP.

6. Transmission Components of Phase II Framework

a. Party Positions

121. The Phase II Framework proposes a two-step transmission planning process.[84] The first step chronologically, referred to in the Phase II Framework as "proactive planning," would focus on assessing needs and alternative solutions for transmission infrastructure needed to support the supplemental RFP. This step begins with the establishment of a Colorado Coordinated Planning Group ("CCPG") Task Force (which has already been accomplished), a study that would continue through March 2026, submission of a CPCN application at the end of 2026 or in early

[84] Hr. Ex. 144, JTS Phase II Framework Redline, p. 2.

2027, and a CPCN decision in August 2027, which would inform bids for the supplemental RFP that will be issued in mid-2027.[85]

122. The second step proposed in the Phase II Framework, referred to as "implementation" or "deliverability/reliability" planning, would focus on the transmission needs of the portfolios approved from the base and supplemental RFPs. In this step, the Company would provide up to four reliability and deliverability analyses as part of the Company's 120-Day Report in early October 2026. The Phase II Framework envisions an opportunity for the Commission to provide feedback on these analyses, followed by re-engagement with stakeholders via the FERC 890 Planning Process and culminating in submission of a CPCN application for these deliverability/reliability projects in early August 2027. The Phase II Framework envisions an identical process following the Commission's approval of a portfolio in the supplemental RFP. This latter process would result in a CPCN application in February 2029.[86]

123. In Hr. Ex. 121, Attachment SM-3, the Company lists the tentative timelines for various steps in both the proactive step and the implementation step.

124. The Phase II Framework also specifies that a small stakeholder group, composed of Staff, CEO, UCA (all supported by the ITA) and the Company would be convened in Summer 2025 to inform both near-term and future transmission planning and modeling. As proposed, this includes revised transmission modeling to be implemented as part of Phase II. This small stakeholder group would have insight and input into both of the steps described above.[87]

125. Staff states that the Phase II Framework provisions bring more oversight to transmission planning and better aligns the timing of transmission projects with the development

[85] Hr. Ex. 145, JTS Phase II Framework, p. 3; Hr. Ex. 121, Martz Rebuttal, pp. 42-45.
[86] Hr. Ex. 145, JTS Phase II Framework, p. 3; Hr. Ex. 121, Martz Rebuttal, pp. 46-48.
[87] Hr. Ex. 144, JTS Phase II Framework Redline, p. 3.

of new resources and load, while giving bidders more certainty regarding the transmission costs that may be needed for their projects. Staff promotes the small stakeholder group as critical, giving its members an opportunity for input and oversight throughout the process that will shape the planning presented in the 120-Day Report and transmission CPCN applications.[88]

126. While CEI broadly supports the Phase II Framework, it asks for certain modifications regarding the transmission elements. First, CEI opposes the fact that the transmission timelines are "tentative," arguing that developers must know where the new transmission lines are located before they bid into the next RFP. CEI requests the Commission direct that these transmission timelines set forth in Hr. Ex. 121, Attachment SM-3 be mandatory.[89] CEI also opposes the Phase II Framework's transmission stakeholder process, because it currently includes no IPP interests. CEI recommends that any changes to the transmission adder or transmission credit only be adopted with additional guardrails such as notice and the ability to comment, consistent with Staff's suggestion during hearing.[90]

127. UCA expresses concern that members of the JTS Transmission Task Force established at CCPG will not be able to vote in the CCPG process. UCA therefore recommends that the Commission direct the Company to consider and evaluate projects proposed by members of the Task Force.[91]

b. Findings and Conclusions

128. We approve the transmission elements of the Phase II Framework, which are largely unopposed. The two-step approach for proactive planning and implementation planning helps align the timing of transmission projects with the development of new resources and load.

[88] Staff SOP at p. 6.
[89] CEI's SOP at p. 25.
[90] CEI's SOP at p. 26 (citing Hr. Tr. June 23, 2025, p. 196).
[91] UCA SOP at p. 14.

We further support the small stakeholder group and hope that the added oversight and analytical review will improve transmission planning before proposals are submitted to the Commission.

129. Turning to CEI's two transmission requests, we reject CEI's first recommendation to convert the tentative transmission timelines to mandatory timelines. While we agree with CEI that clarity regarding the location of additional transmission investment will be important for a successful supplemental RFP, transmission planning is complex, and the Company may not be able to meet strict deadlines. Nevertheless, we emphasize that one of the main justifications for approving the Phase II Framework is the Commission's understanding that the Company will be able to file a CPCN application for proactive transmission investments at roughly the same time as the supplemental RFP. Thus, it is important that the Company strive to meet the tentative timelines. Regarding CEI's second request, CEI raises legitimate concerns about changes to the transmission adders or credits that are made after this Decision. Accordingly, as set forth more in Section L, if the small stakeholder group modifies the transmission adders or credits that will be used in Phase II, Public Service must notify the parties of such a change, and parties will have an opportunity to respond.

130. In response to UCA's concern regarding the JTS Transmission Task Force established at CCPG, the Commission expects UCA, Staff, and CEO to work together with the support of the ITA to develop modeling alternatives. It is also our expectation that the Company will model all alternatives that this group, with advice of the ITA, agrees upon and submits.

F. Contribution of EVs and BE to Load Forecast

1. Load Forecast from EVs

a. Party Positions

131. Public Service's base forecast projects transportation electrification to cause 710 MW in incremental, retail summer peak by 2031.[92] The retail winter peak impact of incremental EVs is projected to be 1,053 MW by 2031. Those values were based on a "High" adoption scenario whereby over 827,000 EVs are based primarily in Public Service's service territory, and over 98 percent of those are Light-duty vehicles.[93] The Company also conducted a lower "Mid" adoption scenario whereby just over 697,000 EVs are operating in the service territory, essentially representing a one-year delay in deployment by the end of the RAP. The "Mid" adoption projection was incorporated in the Company's low forecast. 2024 EV adoption values were estimated at between 114,000 and 140,000, approximately, based on the adoption trend applied.[94]

132. The Base Case and Low scenario EV forecasts estimate EV adoption using two modeling techniques: (1) Bass diffusion modeling, and (2) economic modeling. After establishing forecasts through both methods, the Company averages the results to estimate EV adoption. Bass diffusion models are used to describe technology adoptions patterns in an existing market through an "S" shaped diffusion characteristic and calibrated using state-specific historical EV sales. Economic models use simple payback analysis to estimate potential adoption, incorporating factors such as battery prices, tax incentives, and fuel savings. The Company also incorporates into both the Bass diffusion and economic models a factor for the percentage of vehicles in urban and rural areas, as urban areas have experienced higher adoption than rural areas to date.

[92] Hr. Ex. 114, Goodenough Supplemental Direct, Table SD-6.
[93] Hr. Ex. 101, Att. JWI-2, Vol. 2, Table 2.2-7.
[94] Hr. Ex. 101, Att. JWI-2, Vol. 2, Table 2.2-7.

133. The Base and Low forecast scenarios utilize one managed and one unmanaged charging profile through 2027. The share of managed charging begins at a program participation rate of roughly 10 percent and increases linearly at a rate of an additional 2.5 percent until it reaches roughly 70 percent by 2050. Public Service currently operates one passive managed charging program (*i.e.*, Own Your Charge) and one dynamic managed charging (*i.e.*, Charging Perks); the Company states that more customers participate through the Own Your Charge program than the Charging Perks program.[95] At the projected increase, the Commission calculates that participation in the Company's managed charging programs is expected to reach just under 30 percent by 2031, the last year of the RAP.

134. At hearing, Public Service described that its managed charging load shapes "quickly get to a point where EVs are setting the peak [and] the hour of maximum EV charging is the system peak."[96] To mitigate that effect, the Company implemented a system it refers to as "tranching" in order to simply "move that load around" by shifting it earlier or later in the day to "mimic a managed program… incenting charging at different hours."[97] Public Service explains that, beginning in 2028, all vehicle classes begin to split new managed load additions between multiple tranches.[98] For light-duty vehicles, there are four additional tranches, shifted backward by three, six, 10, and 13 hours. For medium- and heavy-duty vehicles, there is only one additional tranche shifted backward by three hours. The Company explained that it shifts sales toward these additional tranches until sales are roughly equivalent with the original managed charging profile, at which point additions are split evenly across all tranches. The Company also presented

[95] Hr. Tr. June 18, p. 26. The Commission notes the Public Service witness overseeing the load forecast, Mr. Goodenough, had very limited insight into the managed charging programs.
[96] Hr. Tr. June 18, pp. 24-25.
[97] Hr. Tr. June 18, p. 25.
[98] Hr. Ex. 101, Tech. Appendix Vol. II, p. 34.

information that class peak is partially mitigated through its managed charging programs but only presented information for 2025, 2040 and 2050.

135. WRA and SWEEP suggest the Commission should direct the Company to distinguish between plug-in hybrid electric vehicles ("PHEVs") and full battery electric vehicles ("BEVs") and incorporate this distinction into load forecasting.[99] WRA and SWEEP contend Public Service should assess the potential for double-counting due to EV load being present in the baseline use per customer model, and make any necessary adjustments to eliminate double counting.[100] WRA and SWEEP also suggest the Company better distinguish between Level 1 and Level 2 charging (*i.e.*, 120 vs. 240 volts) profiles and usage profiles, and should modify its managed charging profiles to be non-coincident with gross load peak, net load peak, and hours of highest reliability concern. In addition, they argue the Company should be directed to increase its projections of managed charging participation to match the 2024-2026 Transportation Electrification Plan and to use an S-curve growth pattern for future managed charging participation.[101] WRA also suggests the Company eliminate two of the managed charging tranches "as they appear to contribute added load" and to better distinguish between Level 1 and Level 2 charging patterns.

136. CRES/PSR notes that the materials presented during the Joint Technical Conference indicate that the Company is not taking advantage of renewable energy patterns to meet load requirements. CRES/PSR suggests daytime curtailments have been a problem since large quantities of utility-scale PV that became operational in mid-2023 with up to 75 percent of curtailments between 8AM and 8PM on an annual basis during the 2023-2024 period.[102]

[99] Hr. Ex. 1301, Eiden Answer, p. 10.
[100] Hr. Ex. 1301, Eiden Answer, p. 14.
[101] Hr. Ex. 1301, Eiden Answer, p. 67.
[102] Hr. Ex. 1600, Sinton Answer, p. 22.

137. CEO suggests the Commission use 15 percent as starting point for EV managed charging participation rates.[103]

138. In Rebuttal, the Company argues that WRA and SWEEP miscalculated the percentage of customers enrolled in managed charging and provides no evidence for the assumption that customers will opt in based on an S-curve pattern typically assumed for technology adoption. Public Service continues to argue that a linear adoption path for future managed charging projections is more appropriate. As for WRA and SWEEP's concerns about double-counting, the Company generally agrees and offers to "back out estimates of historical EV load" in its Phase II forecasting.[104]

139. With respect to WRA and SWEEP's suggestion to eliminate two EV charging tranches, Public Service argues WRA and SWEEP incorrectly characterize the tranched approach, and that the managed charging program limits the contribution to system peak to 22 MW in 2031 across all five tranches.

b. Findings and Conclusions

140. The Commission notes that transportation electrification adoption and charging patterns will become increasingly important in serving the Company's peak loads. According to Public Service projections, this facet of load accounts for 22 percent of the peak demand growth, or 7 percent of total peak by 2031.

141. Regarding adoption, the Commission notes that, after roughly 10 years of EV adoption there are roughly 140,000 EVs operating in the Company's service territory by the end of 2024.[105] Public Service's "High" EV projection, incorporated in the Base forecast, adds roughly

[103] Hr. Ex. 400, Hay Answer, p. 7.
[104] Hr. Ex. 122, Goodenough Rebuttal, p. 26.
[105] Hr. Tr. June 18, p. 19.

that level every year in the latter half of the RAP. The lower "Mid" EV adoption projection incorporates a slightly lower but still aggressive adoption rate where additions to the pool of EVs in the Company's service territory escalate more slowly. We find the lower EV adoption rate in the "Mid" forecast is more consistent with historical patterns and better reflects new barriers such as the loss of the federal and state EV rebates. Public Service indicated it will update its economic models to include the change in federal law as part of their Phase II forecast.[106] While the Company's updated economic modeling likely reduces the Company's projection of EV adoption, we find it necessary to direct Public Service to update its load forecast for the base RFP using the "Mid" EV adoption trend as presented in the Company's technical appendix to its application, to net out EVs existing prior to mid-2024 when the Company's forecast was conducted, and to provide up-to-date information on actual adoption and economic model output in all future forecasts including those developed to support the Supplemental RFP and the Company's next ERP.

142. With respect to the Company's commingling of PHEVs and full BEVs, we agree with WRA and SWEEP that there are important distinctions between the two vehicle types relative to battery capacity and the likely willingness to participate in managed charging programs (as PHEV owners have two fuel options: electricity and gasoline). Public Service suggests incorporating such differences is part of the "natural progression of improving forecast assumptions" and "something that we are exploring now."[107] While we appreciate that Public Service recognizes the importance of distinguishing PHEVs from BEVs, we find it necessary to clearly specify our expectations in the Company's forecasting efforts. We direct

[106] Hr. Tr. June 18, p. 20.
[107] Hr. Tr. June 18, p. 17:21-24.

Public Service to distinguish between battery capacities and willingness to participate in managed charging programs, among other appropriate attributes, amongst PHEVs and BEVs in its service territory as part of its revised load forecast the Company will use for the base RFP, and to submit its revised forecast to the Commission prior to publication of the Phase II RFP. We also direct Public Service to distinguish between PHEVs and BEVs in this manner in all future load forecasts including those for the Supplemental RFP and the Company's 2028 ERP.

143. As for the managed charging participation rates and program designs, we agree with WRA and SWEEP that the Company must increase its projections of future managed charging for purposes of its load forecast. We find the Company's effort to mitigate expansion of peak load inadequate. We recognize that the tranche concept was incorporated by Public Service in order to mitigate the impacts of the managed charging programs on peak loads without the benefit of delving substantially into program design issues which were outside the scope of this proceeding. Nonetheless, balancing party arguments, we recognize that meaningful improvement in managed charging participation rates and innovative program design will be critical to electrifying the transportation sector affordably. We note the Company is also before us requesting over $1 billion per year in distribution system investment via the Company's combined Distribution System Plan ("DSP") / Aggregated Virtual Power Plant ("AVPP") proceeding.[108] That proceeding is expected to engage the private marketplace through the pooled management of EVs and other technologies, and could expand on the peak load-mitigation capabilities of the Company's programs. Additional expansion of managed charging could further occur through the Company's upcoming Demand-Side Management and Transportation Electrification Program

[108] *See* Proceeding Nos. 24A-0547E and 25A-0061E, the Company's consolidated Distribution System Plan and Aggregate Virtual Power Plant Application.

applications in 2026. Accordingly, through these efforts, there will be ample opportunity to engage customers in managed charging programs critical to meeting electrification goals affordably. Therefore, we direct the Company to incorporate an overall managed charging participation rate of 50 percent for BEVs and 90 percent for PHEVs by 2031 for the purposes of the revised load forecast the Company will use for the base RFP. Future load forecasts should blend these Commission expectations with actual managed charging participation experience. Further, given the growing importance of managed charging programs, we direct the Company to fully support its managed charging programs – including relevant design elements and participation rates – as part of its next ERP including appropriate expert testimony, supporting data and thorough analysis as necessary to meaningfully weigh the Company's managed charging approach to its application for additional supply resources.

144. We also direct the Company to explore in the context of the next Transportation Electrification Plan filing additional ways to improve the managed charging programs and participation, including the possibility of requiring customers who take advantage of utility-sponsored rebates to participate in the managed charging program as a condition of receiving the rebate.

2. Load Forecast from BE

a. Party Positions

145. According to the Company's application, incremental building electrification is projected to cause a five percent increase in energy consumption (or, 2,835 GWh) and a one percent growth in retail peak loads (or, 134 MW) by 2031, the last year in the Company's initial RAP.[109] Notably, the Company projects a 662 MW increase to the winter peak, or roughly five

[109] Hr. Ex. 114, Goodenough Supplemental Direct, Tables JMG-SD-3 and JMG-SD-4.

times the summer peak impact, within the initial RAP.[110] The Company also suggests that its resource needs will increasingly be driven by the winter period beginning in the 2030s.[111] The Company incorporates the same BE-related projection for both its Base and Low forecast.

146. Resource requirements associated with BE are driven by three primary factors: (a) the adoption rates of various BE technologies, (b) the usage patterns of BE appliances, and (c) the electrical requirements of BE technologies (*e.g.*, any supplemental heating requirements). With respect to adoption rates, the Company projects relatively modest adoption patterns through 2026 based on the relevant program goals approved via the Company's DSM Strategic Issues proceeding.[112] In 2027, when the Company's Clean Heat Plan ("CHP") programs come into full implementation, BE adoption is projected to increase dramatically through the end of the RAP. Due to the timing of the JTS Application and supporting analysis, CHP-related adoption is based on Public Service's Amended Preferred Portfolio (presented via Rebuttal Testimony) in its CHP proceeding.[113] The Company indicated at hearing that it would update the forecast to incorporate the Commission's final decision in that case and additional requirements set forth from the decision in the instant case.[114] Accordingly, while final BE adoption values are not known, the JTS includes significant increases in adoption rates. For example, residential water heating BE technologies are projected to increase from 9,289 units in 2026 to over 122,000 units in 2027 (*i.e.*, a 13-fold increase in one year) and ultimately grow by over 100,000 per year to approximately 562,000 by 2031 (before any likely upward adjustment due to the Commission's CHP decision). All-electric heat is projected to grow somewhat slower but still dramatically, adding over 20,000

[110] Hr. Ex. 114, Goodenough Supplemental Direct, Table JMP-SD-6.
[111] Hr. Ex. 102, Landrum Direct, Rev. 1, pp. 34-35.
[112] Hr. Ex. 101, Att. JWI-2, Table 2.2-8, p. 36.
[113] Hr. Ex. 114, Goodenough Supplemental Direct, pp. 19-20.
[114] Hr. Tr. June 18, p. 21.

homes per year from 2026 to 2031.[115] Public Service explains that adoption rates approved in the DSM or CHP proceedings are extrapolated from the growth rate in the final approved year through the end of the forecast period.

147. With respect to BE usage patterns, the Company's technical appendix indicates that the Company applies hourly usage patterns for residential water heat developed by NREL, including peaks driven by relatively inefficient electric resistance elements heat pump water heaters utilize once the water heating tank is emptied due to high usage. At the Joint Technical Conference, the Company agreed with assertions that such usage patterns are highly unlikely to be consistent across customers and offered to apply a flatter electric usage pattern across the pool of residential hot water BE appliances.

148. With respect to the electrical loads of BE technologies (including supplemental appliance usage), the Company's filing offers a figure indicating total peak home usage of approximately 17 kW at -25 degrees F.[116] When asked for supporting documentation to the figure, Public Service referred to the testimony of another witness in another proceeding.[117]

149. WRA and SWEEP and other parties suggest that the load forecast should assume building electrification levels that reflect the Company's approved Clean Heat Plan.[118] WRA and SWEEP also state that Public Service is applying inconsistent assumptions among its electric and gas planning proceedings. In 24M-0261G, which represents a lead-up to the Company's upcoming Gas Infrastructure Planning application, the Company uses lower BE assumptions, leading to

[115] Hr. Ex. 101, Att. JWI-2, Table 2.2-8, p. 36.
[116] Hr. Ex. 101, Att. ZM-1, p. 38 (Figure 4-5).
[117] Hr. Ex. 1301, Att. AE-39, p. 1. (In the Company's response to WRA and SWEEP's question, the Company referred to Hr. Ex 111, Pollock Supplemental Direct, Section IV in Proceeding 24A-0547E (the DSP Proceeding). Mr. Pollock did testify in the instant Proceeding, but his testimony was limited to distributed energy resources and did not directly address the electrification requirements of all-electric homes.)
[118] *See, e.g.*, Hr. Ex. 1301, Eiden Answer, p. 99.

higher gas demand. Meanwhile, the Company's base forecast in the JTS—concerning electric system planning--uses higher BE assumptions, leading to higher electric demand.

150. WRA and SWEEP argue the Company's current projections of BE adoption result in an "unlikely trajectory."[119] They assert that the both the Company's base and low forecasts "assume that sales of residential all-electric heat pumps increase by about five-fold between 2026 and 2027, and that sales of residential heat pump water heaters increase by about twenty-fold between 2026 and 2027."[120] WRA and SWEEP characterize this rapid increase as "improbable."

151. WRA and SWEEP also question the Company's assumptions regarding back-up systems related to heat pumps. WRA and SWEEP note that the Company's assumed household peak use of 17 kW of load at a temperature of -22F (12 kW from the heat pump and another 5 kW from supplemental electric resistance heating).[121] WRA and SWEEP argue that, by assuming that the average all-electric heat pump installation will have significant electric resistance backup, the Company effectively negates its assumption about adoption of highly efficient heat pumps. WRA and SWEEP also argue this assumption does not reflect real-world best practices for installing highly efficient systems. WRA and SWEEP explain that in the Company's CHP case, multiple Colorado-based heat pump contractors testified about the practices they use when sizing and installing heat pumps and about peak load impacts. For example, two-thirds of Elephant Energy's installations in the Front Range of Colorado do not have any supplemental or backup electric resistance heating.[122] There is also data that Elephant Energy's heat pump installations held their setpoint throughout a December 2022 cold snap, during which temperatures in the Denver

[119] Hr. Ex. 1301, Eiden Answer, p. 92.
[120] Hr. Ex. 1301, Eiden Answer, p. 95.
[121] Hr. Ex. 1301HC, Eiden Answer, p. 102, fn. 161.
[122] Hr. Ex. 1301HC, Eiden Answer, p. 101 (citing Proceeding No. 23A-0392EG, Hr. Ex. 1905, p. 5:13-20).

metropolitan area reached a low of -22 degrees F.[123] WRA and SWEEP assert that even for heat pump installations that do require supplemental electric resistance heating, the size of the supplemental heating strips is typically 3 to 8 kW.[124] WRA and SWEEP ultimately recommend the Commission should assume a supplemental heating load of 3 kW and a total peak all-electric household use of 10 kW, rather than the 17 kW peak load the Company assumes.[125]

152. CEO suggests the Commission use the approved CHP portfolio BE assumptions, model increasing heat pump sales post-2030.[126]

153. In Rebuttal, In Rebuttal, Public Service disagrees with WRA and SWEEP's suggestion that backup resistance heat results in only a 3 kW load. The Company asserts that WRA and SWEEP's testimony is based on evidence in another proceeding and is not necessarily accurate information. Public Service further notes the cited range from the other proceeding is 3 to 8 kW, yet WRA and SWEEP recommend using the lowest value in that range. Conversely, Public Service asserts that the Company's modeling is based on a rigorous two-step process where the heat requirement for the building is determined first. After the heat requirement is known for each hour, the most efficient combination of available equipment is utilized to provide the required heat. According to Public Service, arbitrarily limiting the size of one available heating technology (electric resistance heat) does not reflect the choices customers have when selecting or operating their heating equipment. Finally, the Company argues that WRA and SWEEP assume that all electric resistance heat is included in the original installation of the heat pump system. In reality,

[123] Hr. Ex. 1301 HC, Eiden Answer, p. 101 (citing Proceeding No. 23A-0392EG, Hr. Ex. 1905, Att. JL-2).
[124] Hr. Ex. 1301HC, Eiden Answer, p. 101 (citing Proceeding No. 23A-0392EG, Hr. Ex. 701, p. 10, Table DP-2).
[125] Hr. Ex. 1301, Eiden Answer, p. 102.
[126] Hr. Ex. 400, Hay Answer, p. 7.

Public Service argues, customers may easily add plug-in electric resistance space heaters to their homes at any time.[127]

b. Findings and Conclusions

154. As mentioned above, the Commission understands BE-related peak loads driven by three primary factors: (a) the adoption rates of various BE technologies, (b) the usage patterns of BE appliances, and (c) the electrical requirements of BE technologies (or the customers that adopt those technologies including, for example, through supplemental heating sources). With respect to adoption patterns, we generally agree with parties who argue that the BE adoption forecast should be consistent with the Commission's decision in the CHP proceeding. In that proceeding, the Commission required an aggressive effort to reduce greenhouse emissions associated with the Company's gas system. We note, however, that CHP related adoption was expected to begin in the second half of 2024, but the Company's actual adoption rates are delayed relative to the planned adoption rates from the CHP proceeding. We also note that CHP budgets were only approved through 2027 even as we generally recognized the emissions reduction projection in the approved CHP portfolio through 2030. While the Company's CHP remains a critical goal of the Commission, we believe it is necessary to avoid expensive over-building of the electrical supply portfolio in anticipation of load that materializes at a far slower pace than proposed in another proceeding, potentially causing unnecessary rate and bill impacts. We also find Public Service's projected 2027 shift in BE technology adoption to be inconsistent with actual adoption patterns. Accordingly, we direct the Company to revise its forecast of BE technology adoption in the following manner:

i. Incorporate actual adoption rates through at least first half of 2025 (or additional quarters of data, if available) in the Company's updated load forecast. This step

[127] Hr. Ex. 122, Goodenough Rebuttal, pp. 20-21.

should ensure the Company's reforecast includes customers' actual adoption rates for, separately, hybrid space heating, all-electric space heating, and water heating for residential and commercial customers;

ii. Apply the delay experienced to date in customer adoptions to the approved adoption rates embedded in the DSM-SI and CHP proceedings. Continue until the funds currently approved via the most recent DSM-SI and CHP proceedings are projected to be exhausted given current delays;

iii. Grow the final year BE budgets (as approved in the DSM-SI and CHP proceedings) through the remainder of the RAP at the general rate of inflation;

iv. Develop a thorough projection of most-likely BE adoption rates for both electric and gas systems and submit such as part of the Company's upcoming 2026 DSM/CHP proceeding. The Commission will have an opportunity to reevaluate program expenditures and associated adoption rates in that proceeding; and,

v. Revise the load forecast for the Supplemental RFP with the Step iv. projection required for the DSM/CHP proceeding, if available at that time. If not available, conduct Steps i and ii with then-current info in any load forecast that supports the Supplemental RFP.

155. To be clear, the Commission is excited to support Colorado's leadership in decarbonization and electrification of loads, but we recognize the need to be as precise as possible regarding the projected load forecasts. Building too much generation too fast will likely and unnecessarily increase rates, which could discourage efforts to promote BE. The approach we adopt above uses the assumptions in the prior CHP but adjusts them to reflect up-to-date information regarding actual adoption levels.

156. With respect to usage patterns for BE technologies, we note that the Company voluntarily retracted its application of the NREL water heating curve. We find this appropriate and direct the Company to evaluate, to the extent possible, water heating requirements and electrical usage patterns for a sample of customers for presentation and review in the Company's next ERP filing. Regarding the usage patterns of space heating technologies, we note that – as with EVs – active management of will be critical to efficient and cost-effective use of available resources. It is imperative that the Company continues to expand its capability in this area through

its various demand response, VPP, and similar initiatives to mitigate coincident loads causing system and component-level peaks.

157. With respect to the electrical requirements of BE technologies, we find merit in WRA and SWEEP's arguments that the Company's analysis likely exaggerated the resources needed to serve all-electric customers. In the context of this Proceeding, WRA and SWEEP noted two sources from the Company's CHP proceeding: one that suggested most of its customers require no supplemental heat whatsoever and were able to maintain their household setpoint temperature even during a recent deep freeze; and another that suggested a range of supplemental heating requirements from 3 – 8 kW. WRA recommended a 3 kW supplemental heating requirement and a total household use of 10 kW based on those two testimonies. The Company argued that the testimony WRA relied upon were made by other witnesses in another proceeding. While we appreciate and understand that context, the Commission finds that the testimony referred to by WRA and SWEEP from the CHP proceeding in its Answer Testimony is relevant and informative, and that the Company had appropriate opportunity to respond both in testimony and at hearing. We note that technical issues such as these can play out over many cases, and it can be difficult for parties to engage with its witnesses (who, in this instance, are full-time implementers in the field) over multiple years and cases. Nonetheless, the issues and uncertainties addressed by the installers in the CHP proceeding are strikingly similar to the issues raised here by WRA and SWEEP, and the installers are directly engaged in the design, implementation and maintenance of these systems in the field. Accordingly, we find the testimony from the installers to provide useful insight and input to our Decision here, and it was raised by parties such that appropriate response could be provided by the Company for consideration as well. To that end and on balance here, we also note that the Company provided essentially no analysis in the instant

Proceeding to support its own assumptions. In fact, Public Service itself referred to another witness in another proceeding to justify its input calculations. Particularly where we are considering modeling inputs for analysis in Phase II, for purposes of the instant Proceeding, we find that WRA and SWEEP's suggested 10 kW average household peak usage to be a reasonable starting value for this important input. We direct Public Service to incorporate that value into its revised forecast for the base RFP.

158. Further, we believe the ongoing DSP proceeding (Proceeding No. 24A-0547E) will provide additional opportunities to revisit this issue and is likely to afford us an improved record including the availability of limited AMI data. We intend to further evaluate this issue there and in other future applications so that we may incorporate the best information available when approving investments – and ratepayer dollars – into the Company's energy supply, transmission and distribution infrastructure, including the load forecast that will be used in for the supplemental RFP. With respect to the utilization of AMI data, we believe strongly that such data is central to the issue of comprehending the system and local electrical capabilities required of the Company's growing electric system through unprecedented insight into actual energy requirements across a wide array of customers, geographic regions, weather conditions, and specific technology adoption (to the extent known or discernible). Given the fact that Public Service recently completed the rollout of AMI meters across 1.4 million customers, we expect the Company's ability to evaluate and manage customer usage patterns via AMI data to improve dramatically in subsequent resource and system planning applications.

159. Moving forward, the growing electrical load associated with both BE and EVs have the promise to benefit the system and help provide downward pressure on rates. This promise, however, is contingent on advances in demand response, managed charging, and other programs

or rate structures that minimize the impacts that BE and EVs have on the peak system need. More specifically, the Company seems unable or unwilling to effectively take advantage of the opportunity and instead assumes that these new technologies and uses justify multi-billion-dollar capital spending increases across both the electric and gas systems. As such, this Commission will continue to push for different rate structures, tariffs, and programs, including those that link customer rebates to required participation in managed use programs, that better advance active control of these loads.

160. Despite existing technology that can, for example, cost-effectively manage EV charging by time-of-day, despite the fact that EV batteries soon may be able to back-feed homes in ways that offset other peak demands, and despite Commission orders to significantly increase managed charging incentives, the regulated system must do better at driving EV charging and other similar BE loads off the critical system peak demand hours. The promise of these technologies is to flexibly reduce demand at critical times, yet the Company seems unable or unwilling to take advantage of these opportunities, which looks to result in higher resource needs, adverse rate impacts and reliability risk. More broadly, this Commission may need to explore third-party implementation models for some of these programs given some of the resistance or inability to earnestly pursue these priorities, misaligned financial incentives, and proposed customer costs. We intend to do this through future proceedings including the transportation electrification plans, DSP and VPP proceedings, and rate cases.

G. Strategic Resilience Reserve Fund

1. Party Positions

161. On April 2, 2025, Public Service filed a Notice of Filing and Hearing Exhibit 115, which provides an overview of the Strategic Resilience Reserve Fund concept.

Public Service states the strategic reserve fund is directly responsive to discussion at the Joint Technical Conference and is designed to allow the Company to acquire combustion turbines ("CTs") and transformers to help advance dispatchable generation and transmission projects to facilitate resource portfolios in the JTS.

162. Public Service proposes that the strategic reserve fund would not exceed $500 million in expenditures (for either physical equipment or production slots for eligible equipment) and that the Company would recover the costs associated with the strategic reserve fund through the Purchased Capacity Cost Adjustment ("PCCA"). The Company would earn a return on the invested capital at the Company's weighted average cost of capital ("WACC"), including the costs of any storage or handling costs associated with the equipment.

163. Staff argues the Commission should reject the strategic reserve fund. Staff asserts the Company has failed to show the need for the strategic reserve fund and the proposal lacks ratepayer protections. Staff states there is no indication Public Service is currently prevented from securing manufacturing slots or purchasing equipment without the strategic reserve fund, nor has the Company shown that it will not be able to timely deliver projects or energy supply without the strategic reserve fund. Staff cites testimony from the hearing showing that the Company can and has taken steps well in advance of CPCNs to procure equipment. This includes most recently taking action to reserve and secure gas CTs and wind turbines prior to the Phase II Decision in the 2021 ERP/CEP.[128]

164. Staff goes on to argue that the $500M budget is arbitrary. Staff suggest the Company could use the entire $500M to purchase CTs, which could eventually be used for future Company-owned projects outside the JTS. According to Staff, the proposed strategic reserve fund

[128] Staff's SOP at p. 25.

significantly benefits the Company by shifting nearly all financial risks to ratepayers, generating additional profit, and potentially placing Company-owned project bids at a competitive advantage.[129]

165. Like Staff, CEO opposes the strategic reserve fund and recommends the Commission reject it. CEO asserts the Company admitted during the hearing that only HVDC and CTs require a reservation payment to enter the manufacturing cure—breakers and transformers do not. Regarding HVDC equipment, CEO asserts the Company does not have a clear proposal for such equipment at this time, so the Commission should reject cost recovery for HVDC equipment purchased through the strategic reserve fund. As for CTs, CEO notes the Company admitted during hearing that it reserved gas CTs for two utility-owned projects in the 2021 ERP/CEP in March 2023, which was nearly 10 months prior to the Commission's Phase II decision issued in January 2024. CEO also asserts the Company admitted that it has already secured several gas CT slots for the current ERP cycle, even though they are not tied to a specific project. CEO thus argues that Public Service has already contributed its own capital to secure manufacturing slots for gas CTs and does not need the strategic reserve fund to do so.[130]

166. In the alternative, CEO argues the Commission should at least make significant modifications to the strategic reserve fund proposal, including narrowing the scope and limiting approval to only gas turbines for costs required to enter a queue, deposits to maintain queue position, or final payments. CEO further argues that the Company should make equipment acquired through strategic reserve fund available to both IPP and utility-owned generation projects on an equitable basis.[131]

[129] Staff's SOP at p. 26.
[130] CEO's SOP at pp. 28-29.
[131] CEO's SOP at pp. 29-30.

167. CIEA recommends the Commission approve a significantly modified strategic reserve fund that focuses on transmission and interconnection equipment and equitably distributes such equipment between IPP and utility-owned projects. Specifically, CIEA argues the strategic reserve fund should focus on reserving "high-side" interconnection facilities that are ultimately owned by Public Service. CIEA suggests that strategic reserve fund equipment acquisition costs could be noticed to the JTS parties, and strategic reserve fund equipment acquired and the associated cost should be listed in the RFP. The Company would be reimbursed by IPPs for the overnight costs of the equipment via the LGIP, or costs could be recovered via the ESA which could lower bid prices.[132]

168. Under CIEA's approach to the strategic reserve fund, Public Service would acquire sufficient transformers and breakers to connect entire selected, or Commission-approved, portfolio. CIEA reasons that under its strategic reserve fund proposal, the acquisition process for necessary interconnection equipment could be accelerated by as much as two years.

169. Similar to CIEA, CEI supports a modified version of the strategic reserve fund that focuses on transmission and interconnection equipment that is provided to developers in an ownership-agnostic and transparent manner. CEI asserts the Company's current proposal to acquire CTs that would be reserved for utility-owned generation bids in Phase II raises significant concerns. CEI asserts this aspect is fundamentally anti-competitive because it leverages ratepayer funds to secure critical generation equipment in advance, which IPPs cannot do.[133]

170. CEC opposes the strategic reserve fund and asks the Commission to reject it outright. According to CEC, with the strategic reserve fund the Company seeks to earn a

[132] CIEA's SOP at pp. 26-27.
[133] CEI's SOP at p. 17.

guaranteed return with no associated risk through a program that would leverage ratepayer funds to compete with IPPs for limited resources. CEC recommends the Company continue to purchase equipment in the ordinary course of business as it deems appropriate and seek recovery of its expenses in a general rate case.[134]

171. CC4CA argues the Commission should reject PCCA cost recovery for the strategic reserve fund but approve the Company's plan for acquiring or reserving breakers, transformers, and HVDC equipment for recovery in the next rate case. CC4CA asserts the Company has provided no evidence or argument that the PCCA is an allowable cost recovery mechanism for the proposed strategic reserve fund expenses. CC4CA also takes issue with the Company's proposal to earn WACC through the PCCA. CC4CA asserts this would be inappropriate without a tariff modification. Because transformers and breakers can serve all generation resources acquired as part of the JTS, CC4CA asks the Commission to direct Public Service to acquire this equipment with Company reserves, to be recovered through base rates or another appropriate cost recovery mechanisms. Finally, CC4CA warns against allowing strategic reserve fund funding for CTs. CC4CA reasons that doing so would risk biasing the solicitation in favor of Public Service and puts a thumb on the scale of including new gas in the approved portfolio.[135] CRES/PSR likewise opposes the strategic reserve fund.

172. Grid United supports the strategic reserve fund and specifically recommends the Commission either approve the strategic reserve fund's use for HVDC equipment procurement now or clarify that the strategic reserve fund's use can be expanded in future proceedings, including for HVDC procurement. Grid United asserts the evidentiary record is clear and

[134] CEC's SOP at p. 18.
[135] CC4CA's SOP at pp. 24-26.

undisputed that interregional HVDC lines, especially ones like Three Corners Connector that would connect Public Service's system and SPP's to the east, would bring substantial capacity value and customer savings.[136] Grid United thus argues the Commission should ensure that its decision paves the way for future consideration of such projects.

173. The Pueblo Intervenors support the strategic reserve fund as proposed. They reason that allowing the Company to deal proactively with these supply chain shortages and directing them to immediately secure a supply of CTs and transformers will facilitate the construction of replacement generation within Pueblo. The Pueblo Intervenors reference that with the impending closure of Unit 3, workers will need alternative employment, and that construction of replacement generation should not be delayed.[137]

174. In response to intervenor criticisms, Public Service explains the strategic reserve fund proposal is not about accelerating the manufacturing cycle, it designed to address the race for manufacturing slots and to secure critical equipment like turbines, transformers, and breakers.[138] Public Service states it is open to establishing acquisition targets instead of a flat $500M budget. The Company estimates that a $500 million budget could acquire approximately three CTs ($100 million each), 10-15 transformers ($5 million each), and 40-50 breakers ($250,000 each), as an illustrative example.[139] The Company estimates these purchases would allow for approximately 10 interconnected projects in addition to approximately 600 MW of new thermal capacity.

[136] Grid United's SOP at p. 5.
[137] Hr. Ex. 1200, Shaw Answer, p. 14; Hr. Ex. 1201, Graham Answer, pp. 10-11; Hr. Ex. 1202, Swearingen Answer, pp. 14-15; Hr. Ex. 1204, Arnold Answer, p. 5.
[138] Public Service's SOP at pp. 6-7.
[139] Hr. Ex. 116, Ihle Supplemental Direct, p. 11.

2. Findings and Conclusions

175. We agree with parties such as Staff, CEO, and CEC who assert that Public Service has not shown a need for strategic reserve funds to procure CTs. It is unclear why Public Service now needs additional incentive to reserve manufacturing slots for CTs given the strategic reserve fund was apparently unnecessary for the 2021 ERP/CEP. Public Service has also not explained how using strategic reserve fund to acquire CTs would not give the Company a substantial competitive advantage over IPPs who may otherwise bid CTs into the base or supplemental RFPs.

176. On the other hand, the same anti-competitive concerns do not appear to be present for transformers and breakers when such equipment is available to support both PPA projects and utility-owned generation. CIEA and CEI both support a modified strategic reserve fund that focuses on transformers and breakers. Although CEO cites hearing testimony that reserving manufacturing slots for transformers and breakers does not require a down payment, this does not mean that the early procurement of such equipment will be cost free. Moreover, strategic reserve funds would only be recovered once the funds are actually expended.

177. On balance, the Commission finds that the strategic reserve fund concept for transformers and breakers as set forth by CIEA (with a slight modification to cap acquisitions by a $200M budget)[140] is in the public interest. CIEA asserts the acquisition process for necessary interconnection equipment could be accelerated by as much as two years by using CIEA's proposed strategic reserve fund process. This alone could help lower overall costs and increase flexibility. Accordingly, we direct the following: 1) the strategic reserve fund will be available on equitable basis to all PPA and utility-owned projects; 2) Public Service may acquire transformers

[140] The $200M budget we approve for the strategic reserve fund is based on the initially proposed $500M budget but without the anticipated costs of the CTs. Public Service estimated that it would use strategic reserve funds to acquire three CTs at $100M each.

and breakers to help connect the expected Commission-approved portfolio, subject to the $200M budget; 3) PPA and utility-owned bids will include Public Service's overnight costs for transformers and breakers in their bids, which will be noticed in the RFPs; and 4) strategic reserve fund costs can either be incorporated into Large Generator Interconnection Agreements ("LGIA"s) or separated out and recovered via the Energy Cost Adjustment ("ECA").

178. Strategic reserve funds shall not be used to acquire HVDC equipment, at this time. We agree with Grid United that interregional HVDC lines like the Three Corners Connector could bring substantial capacity value and customer savings. Unlike standard transformers and breakers, however, HVDC equipment appears to be application specific.[141] We agree with CEO that Public Service has not demonstrated its plans for HVDC equipment at this time.[142] Consistent with Grid United's alternative request, we clarify that the Commission would be open to Public Service seeking approval for accelerated funds for HVDC equipment in the future once the Company can provide more details on its HVDC plans.

179. Finally, we reject arguments to deny the strategic reserve fund concept outright or eliminate the accelerated recovery of strategic reserve funds. Requiring Public Service to recover costs associated with the strategic reserve fund in the next rate case eliminates the purpose of the strategic reserve fund, which is to provide regulatory certainty the Company needs to acquire long lead time assets on an expedited basis.

[141] Hr. Ex. 116, Ihle Second Supplemental Direct, p. 10.
[142] Hr. Ex. 402, Hay Cross-Answer, p. 34.

H. Just Transition

1. Motion to Strike

180. Moffat and Craig filed a Motion to Strike a portion of Pueblo Intervenors' testimony ("Motion to Strike"). The statement in question, contained in Pueblo Intervenors' SOP, is as follows:

> Craig/Moffat also submitted cross answer testimony claiming that employee impact payments should go to them as opposed to Hayden where the plant is located because many of the employees work at Hayden but live in Moffat County. So Moffat/Craig is fighting with Hayden/Routt as to who should get paid amounts that are not authorized under the statute.[143]

181. The Motion to Strike argues this statement is false, argues alleged facts not in evidence, is advanced for an improper purpose, and should be stricken from the record because (1) Moffat and Craig did not file cross-answer testimony in this Proceeding; (2) there is no evidence in the record that Craig's request for community assistance has been made in lieu of "or as opposed to" the Routt County Governments (rather, their testimony supports Routt County's requests for community assistance); and (3) evidence does not show that the governments have been "fighting," but have been supportive of each other throughout the Proceeding.

182. The Routt County Governments support the motion, Pueblo Intervenors oppose the Motion, and all other parties either take no position or did not respond to conferral.

183. In its response, Pueblo Intervenors contend its statements are supported by the record. Pueblo points to statements made by Routt County Governments witness Commissioner Redmond where he explains that "…it is critical that the Moffat County Government's request not come at the expense of the Routt County Governments. Any interpretation that reallocates or limits Routt County's arguments for economic assistance based on Moffat County's claims of

[143] Pueblos Intervenors' SOP at pp. 20-21.

workforce-related impacts would undermine the purpose of this just transition process."[144] Pueblo also points to Commissioner Redmond's testimony regarding the Carbon Free Future Development Fund where he requests the Commission "[a]nalyze the just transition needs and requests of each just transition community independently and reject any interpretation of the Moffat county Governments' proposal for economic assistance payments as a limitation or subtraction from the economic assistance needed by the Routt County Governments."[145] Pueblo asserts this testimony proves there is a "fight" or dispute between the governments and that it is important to include its statement as it speaks to the problems and confusion that will arise if the Commission fails to follow § 40-2-125.5(4)(a)(VII), C.R.S.

184. We deny Moffat and Craig's Motion to Strike. The Commission has discretion in determining the admissibility of evidence in its proceedings and the appropriate weight to assign to evidence, consistent with § 40-6-101(4), C.R.S. The Commission therefore interprets the quoted testimony not as "fighting," but as the local governments advocating for their own respective interests and weighs the statements of Pueblo Intervenors accordingly in making its determinations in this Proceeding.

2. Background

185. One of the primary issues in the 2021 ERP/CEP was Public Service's proposed coal transition plan. Under this plan, Craig Unit 2 will retire in 2028, Hayden Unit 1 will retire in 2028, and Hayden Unit 2 will retire in 2027. These accelerated retirements were not, however, CEP actions. Rather, in its direct testimony in the 2021 ERP/CEP, Public Service informed the Commission that it had previously decided on the accelerated retirements of these plants in

[144] Pueblo Intervenors' Response to Motion to Strike at p. 4 (citing Hr. Ex. 1803, Redmond Cross Answer, p. 7).

[145] Pueblo Intervenors' Response to Motion to Strike at p. 4 (citing Hr. Ex. 1803, Redmond Cross Answer, p. 9).

conjunction with the plants' other owners. For Craig Unit 2, the Company only owns 10 percent of the plant. The rest of the plant is owned by PacifiCorp, Platte River Power Authority, Salt River Project ("SRP"), and Tri-State Generation and Transmission Association, Inc. ("Tri-State"). Regarding Hayden Unit 1 and Hayden Unit 2, Company owns the units along with PacifiCorp and SRP. Unlike at Craig, however, the Company is the majority owner and operator of the Hayden Station, owning about 75 percent of Hayden Unit 1 and 37.5 percent of Hayden Unit 2.[146]

186. The USA also specifies that the Pawnee coal-fired power plant will be converted to natural gas no later than January 1, 2026. Pueblo Unit 3 is set to retire no later than January 1, 2031. In addition, beginning in 2025, Public Service agreed to begin ratcheting down Unit 3's annual capacity factor. Unlike the accelerated retirements of the coal units at Craig and Hayden, the conversion of the Pawnee Unit and the restrictions Pueblo Unit 3 are considered CEP actions.

187. In the USA in the 2021 ERP/CEP, Public Service committed to modeling in Phase II of the 2021 ERP/CEP just transition costs (*i.e.*, the potential future costs of both workforce transition plans and community assistance plans) for each affected coal plant facing accelerated retirement or conversion (*i.e.*, Hayden, Pawnee, and Unit 3). Public Service maintained during the 2021 ERP/CEP that it was not obligated to provide just transition benefits to Craig 2 because it was a minority owner/non-operator.

188. To model the just transition costs, the Company agreed to use an escalating property tax-based proxy value that runs until the earlier of: (1) a unit's original retirement date (for all units other than Unit 3); or (2) December 31, 2040 (in the case of Unit 3). The estimated cost of the community assistance aspect will be equal to projected lost property tax revenues for six years

[146] *See* Hr. Ex. 101, Jackson Direct, Rev. 1, p. 43 in the 2021 ERP/CEP.

following retirement or conversion for Hayden 1 and Hayden 2, and Pawnee, respectively, and ten years for Unit 3 (*i.e.*, from January 1, 2031, through December 31, 2040, for Unit 3). With regard to Unit 3, the USA further specifically states: "[t]he Company commits to make payments to Pueblo County annually from 2031 through 2040 (and allocated by the treasurer's office accordingly) in the amount of the projected lost property tax revenues for those years, unless offset by property tax revenues from generation or transmission infrastructure sited at Comanche Station or within Pueblo County."[147]

189. The USA contemplates that in 2021 ERP/CEP Phase II, the Commission would approve a final portfolio with the estimated costs of the Just Transition Plan included in the cost estimate of the plan, which will be offset by any investment and corresponding property tax revenue in an affected community. Final community assistance plan costs and workforce transition plan costs (as well as any offsets due to investments in the relevant community) were to be determined in future post-Phase II Just Transition Plan filings. The upshot of the USA's modeling approach is that the model was incentivized to select resources within the just transition communities because these resources would help offset the community assistance payments that were included in the modeling.

190. In addition to the modeling benefits and community assistance payments, the USA requires Public Service to conduct a study to evaluate low-emission or carbon-free dispatchable resources within Pueblo County: "The Company will conduct a study at an amount not to exceed $2 million to evaluate a variety of potential low-emission or carbon-free dispatchable resource

[147] USA, ¶ 42 in the 2021 ERP/CEP.

options located at the site of Comanche Station or within Pueblo County that can contribute to the Company's continued efforts to reduce emissions."[148]

191. In approving the USA provisions regarding the just transition modeling, the Commission noted that although not all communities affected by the coal transition plan are intervenors in the 2021 ERP/CEP Proceeding, Pueblo Country, Pueblo City and Water, and the OJT all support the just transition provisions of the USA.[149]

3. Party Positions

192. In Public Service's Direct Testimony, it recounts the provision of the 2021 ERP/CEP USA committing the Company to a $2 million study for new low-emission or carbon-free dispatchable resources within Pueblo County. The Company explains that this $2 million study led to the formation of the Pueblo Innovative Energy Solutions Advisory Committee ("PIESAC"). Public Service states that many of the Company's just transition proposals come directly out of the PIESAC process.[150]

193. More specifically, the Company frames its just transition proposals as having three distinct proposals: (1) modeling credits that would be applied in Phase II modeling to help drive resource acquisition in these communities; (2) a development component to drive longer-term investments into communities (*i.e.*, the pre-construction development asset proposal[151] and the CFFD proposal[152]); and (3) a broader economic development component to assess which potential new loads have siting flexibility to develop in just transition communities.

[148] USA, ¶ 48 in the 2021 ERP/CEP.
[149] USA, ¶ 109 in the 2021 ERP/CEP.
[150] Hr. Ex. 101, Ihle Direct, Rev. 1, p. 45.
[151] In its Rebuttal, the Company converted the PCDA concept into the incremental need pool. As set forth above, the Commission largely approves the incremental need pool as part of the Phase II Framework.
[152] As set forth in Section I below, the Commission adopts the CFFD proposal, with modifications and clarifications.

194. Starting with the modeling credit, the Company explains that it did not see results from the property tax tail/offset modeling approach used in the 2021 ERP/CEP that suggested it was significant enough to drive investment into the relevant communities. Accordingly, Public Service now proposes to give projects located within Pueblo, Morgan, and Routt counties a modeled benefit, in the form of a $/MWh or $/kw-month bonus, in the bid evaluation.[153] Notably, this modeling piece will be in addition to the property tax tail/offset approach agreed to in the 2021 ERP/CEP USA. The proposed just transition modeling credits are set forth below:

- Projects located within target communities will receive a base credit of $1.00/kw-month or $2.00/MWh
- Projects located within target communities and that create more than 20 long term jobs will receive an additional bonus credit of $.50/kw-month or $1.00/MWh
- Projects located within target communities and that provide more than $4 million in annual property taxes will receive an additional bonus credit of $.50/kw-month or $1.00/MWh
- The total potential credits are $2/kW-month or $4/MWh. [154]

195. Regarding the second component of the Company's just transition proposal (driving longer-term investments into communities), Public Service argues that the Company wants to see long-term proposals in just transition communities, and the CFFD concept facilitates that goal. Public Service argues that longer-timeline resources, such as pumped hydro, geothermal, nuclear, geologic carbon-capture, hydrogen or other technologies are now effectively blocked from serious consideration by the current Colorado resource plan process.[155]

196. As for the third component of the just transition proposal, Public Service states that the just transition communities desire to drive economic development beyond just new generation

[153] Public Service notes these two counties (Routt and Pueblo) will see coal plant retirements occur during the RAP.
[154] Hr. Ex. 102, Landrum Direct, Rev. 1, p. 40.
[155] Hr. Ex. 101, Ihle Direct, Rev. 1, pp. 50-51.

resources. This could include attracting ancillary businesses to the communities (*e.g.*, clean energy-related manufacturing) or siting large new loads in the communities. Public Service adds that if large new loads have siting flexibility, the Company can try and facilitate discussions with just transition communities about siting those loads in these communities. However, the Company adds that it is "not seeking any Commission findings on this respective component of our just transition approach."[156]

197. In addition to the three just transition components above, Public Service states the Company remains firmly committed to making the community assistance payments contemplated in the 2021 ERP/CEP. The Company provides the below estimate of what the community assistance payments would be without any offset for replacement generation or new infrastructure:

- Hayden 1: average payment of $1,246,333 (for six years), for a total payment of $7,478,000
- Hayden 2: average payment of $1,474,833 (for six years), for a total payment of $8,849,000
- Pueblo Unit 3: average payment of $16,243,900 (for 10 years), for a total payment of $162,439,000
- Pawnee: average payment of $3,433,980 (for six years), for a total payment of $20,603,879[157]

198. As for the implementation of the community assistance payments, Public Service states that once the final JTS portfolio is approved, the Company would bring an application filing that would include the community assistance payment values for each community, netted with any new property tax offsets from the portfolio. The Commission would establish the final values through a decision on this application, along with the cost recovery approach as provided for in statute. For efficiency, the Company plans to file single application

[156] Hr. Ex. 101, Ihle Direct, Rev. 1, pp. 52-53.
[157] Hr. Ex. 101, Ihle Direct, Rev. 1, pp. 53-54.

would cover all three communities (Pueblo County, Routt County, and Morgan County) with discrete community assistance payment streams established for each community.[158]

199. The Pueblo Intervenors support the Company's proposed just transition modeling credits as one of the tools that could help ensure a just transition for Pueblo.[159] The Pueblo Intervenors argue that it is much more advantageous for the Pueblo community to have new large capital investments in the community as opposed to community assistance payments.[160] The state the Comanche site generates almost $31 million a year in property taxes a year, which is over 10.5 percent of all property taxes Pueblo County collects, and Pueblo Unit 3 provides almost $200 million annually and direct and indirect benefits to the community.[161] They ask the Commission to do everything in its power to expedite the modelling, bidding, and construction of new thermal/gas units in Pueblo. The Pueblo Intervenors reason that the just transition modeling credits will drive new projects to coal communities and states the Commission should adopt the Company's proposal if the Commission cares about a just transition for Pueblo and other coal communities.[162]

200. As for the community assistance payments, the Pueblo Intervenors generally agree with the calculation of payments for Pueblo the Company puts forth in its Direct Testimony, with one caveat. The Pueblo Intervenors assert that 10-year period over which Pueblo will receive the community assistance payments is a long time, especially if there is a materially high inflation period with materially high interest rates. Pueblo County thus reserves its right to argue that the

[158] Hr. Ex. 101, Ihle Direct, Rev. 1, p. 55.
[159] Hr. Ex. 1200, Shaw Answer, p. 13; Hr. Ex. 1201, Graham Answer, p. 11; Hr. Ex. 1202, Swearingen Answer, p. 8; Hr. Ex. 1204, Arnold Answer, pp. 6-7.
[160] Hr. Ex. 1200, Shaw Answer, p. 12.
[161] Hr. Ex. 1201, Graham Answer, p. 3.
[162] Hr. Ex. 1200, Shaw Answer, p. 13; Hr. Ex. 1201, Graham Answer, p. 8; Hr. Ex. 1202, Swearingen Answer, p. 8.

escalator of two percent is too low.[163] The Pueblo Intervenors also request the Commission issue an order quantifying the community assistance payments and the underlying methodology. According to the Pueblo Intervenors, without such a quantification by the Commission, financial agencies could see this as a vulnerability which could increase the interest rate on any debt Pueblo County issues in the future, or impact on Pueblo County's credit rating.[164]

201. The Routt County Governments generally oppose the community assistance structure agreed upon in the 2021 ERP/CEP USA as well as the Company's proposals in this Proceeding. For instance, the Routt County Governments argue it is inappropriate to provide only six years of property tax backfill, when other communities will receive 10 years of tax backfill. In addition, while the Routt County Governments generally agree with providing a modeling benefit to just transition communities, they argue the Company's proposal will likely have limited effectiveness in driving job and property tax creating generation to the Hayden Station site, noting that a gas-fired plant is neither preferable nor viable.[165] Instead, the Routt County Governments express an interest in geothermal and other non-fossil fuel replacement generation.[166]

202. More fundamentally, Routt County Governments oppose the settlement provisions from the 2021 ERP/CEP. They state they were never asked for input when the settlement was being formed and that it is wrong for their economic future to be decided without the Routt County Governments having a seat at the table.[167] Instead of the Company's proposal, the Routt County Governments argue Public Service can provide a just and inclusive transition by offering

[163] Hr. Ex. 1203, Genesio Answer, p. 3.
[164] Hr. Ex. 1203, Genesio Answer, p. 4.
[165] Hr. Ex. 1800, Redmond Answer, p. 27.
[166] *See* Hr. Ex. 1801, Mendisco Answer, pp. 22-29.
[167] Hr. Ex. 1800, Redmond Answer, p. 26; Hr. Ex. 1801, Mendisco Answer, p. 10.

community assistance which is structured similarly to the Tri-State Settlement. The Routt County Governments specifically request the following:

- $43,590,560 in property tax backfill, to be paid over the next 10 years to taxing authorities within Routt County and which could be offset by new investment;
- $49,409,440 in direct economic development payments, not subject to offset, which will be utilized by the Routt County Governments to accelerate economic development and diversification within Hayden and Routt County;
- An order from the Commission requiring either the dedication of, or a pathway to dedication of, the Hayden Station Spur Line, the Pumphouse Property, any unused water rights currently benefiting Hayden Station after the year 2050;
- Incentives or commitments by Public Service to site geothermal electric generation at the Hayden Station site as replacement generation, whether as part of a standalone RFP or any other form determined to be appropriate by the Commission; and
- A binding commitment by Public Service to fully remediate all environmental impacts of Hayden Station upon final decommissioning or a requirement that the issue be addressed in a future proceeding.[168]

203. As part of the justification for the approximately $90 million in payments and other just transition benefits, the Routt County Governments cite an Economic Impact Report that details the significant impacts that closure of the Hayden Station will bring to the community.[169]

204. Moffat and Craig urge the Commission to require Public Service to pay community assistance payments to Moffat County and Craig. Moffat and Craig argue the Commission must disregard Public Service's "Owner-Operator" argument that attempts to shield the Company from providing Moffat and Craig with a just transition. According to Moffat and Craig, Colorado's just transition statutory framework has no language either (i) exempting "minority" coal plant owners or (ii) mandating the majority owner (or given plant's operator) to be completely responsible for community assistance payments. They argue Public Service is legally obligated to provide

[168] Routt County Governments' SOP at pp. 34-35.
[169] *See* Hr. Ex. 1802, Duffany Answer, pp. 10-12.

community assistance to Moffat County and the City of Craig for the accelerated closures at Craig Station on a proportional basis to its property tax contributions.[170]

205. Based on Public Service's ownership stake in Craig Station, Moffat and Craig argue they should receive a community assistance plan accounting for $14,023,800 which amounts to ten years of the Company's Craig Station annual property tax payments following the closure of Craig Station, subject to infrastructure investment offsets.[171] In addition, Craig and Moffat request a community assistance plan accounting of $14,797,200 for direct labor income effects from the workers employed at the Hayden Station but who live in Moffat County.[172] Thus, Moffat and Craig request a total community assistance funding amount of $28,821,000.[173]

206. Moffat and Craig similarly argue the Company should extend the just transition modeling credits to Moffat County to help satisfy the Company's broader community assistance and just transition obligations to help prioritize resources to coal communities.[174] Moffat and Craig further reason that if the Commission allows community assistance payments to Moffat and Craig, then applying the just transition modeling credits to Moffat County is a logical extension. Investments in Moffat County will help offset community assistance payments.[175]

207. UCA strongly recommends Public Service be required to provide community assistance payments to the City of Craig and its share of Craig Unit 1 and 2's retirement. UCA estimates the Company's proportional obligation to be approximately $6,803,738.31 million for each of these units, totaling approximately $13,607,476.62 million. More broadly, UCA argues the Commission should approve a JTS that not only meets resource adequacy and emissions goals

[170] Moffat and Craig's SOP at pp. 6-8.
[171] Hr. Ex. 2100, Villard Answer, p. 44.
[172] Hr. Ex. 2100, Villard Answer, p. 44.
[173] Hr. Ex. 2100, Villard Answer, p. 44; Hr. Ex. 2101, Nichols Answer, p. 41.
[174] Hr. Ex. 2101, Nichols Answer, pp. 27-30.
[175] Moffat and Craig's SOP at p. 23.

but also supports communities and workers as well as reasonable costs to ratepayers.[176] In its SOP, UCA asserts the Company's refusal to provide any community assistance payments for Craig Unit 1 due to its closure date is a narrow and formalistic interpretation of its obligations that ignores the broader legislative intent. UCA also proposes the Commission order in this Proceeding the use of the same payment structure applied in the Tri-State proceeding regarding the closure of Craig Unit 3.[177]

208. OJT also recommends modifying the Company's community assistance proposals. OJT specifically recommends the Commission follow the just transition framework set forth in the 2023 Tri-State ERP, which OJT refers to as the "Moffat model." In general, under this Moffat model community assistance consists of one-third of the total in direct benefit payments at or near the time of the closure, and two-thirds in minimum backstop payments, starting large and tapering down over time. Deductions for new investments are made only against the backstop payments, and then only for new property taxes received prior to each scheduled backstop payment.[178] OJT details how this Moffat model would work for Pueblo, Morgan County, and Routt County based on the total community assistance commitments Public Service puts forth in its direct case.[179]

209. OJT recommends the Commission require Public Service to provide community assistance payments to Moffat County based on the Company's ownership interest in Craig Station.[180]

210. In its SOP, OJT more generally argues the USA is the floor for crafting a just transition for each community. OJT likewise argues the Just Transition statute (§ 40-2-125.5(4),

[176] Hr. Ex. 300, Sermos Answer, Rev. 1, p. 35.
[177] UCA's SOP at pp. 19-21
[178] Hr. Ex. 600, Buchanan Answer, p. 20.
[179] Hr. Ex. 600, Buchanan Answer, pp. 21-23.
[180] Hr. Ex. 600, Buchanan Answer, pp. 27-28.

C.R.S.) sets the minimum community assistance that a CEP must contain and that arguments that the statute prohibits the Commission from considering other types of assistance ignore the Commission's exclusive and broad authority.[181] OJT argues the Commission can consider alternatives in addition to the minimum requirements in the statute unless the constitution or general assembly expressly prohibit it.

211. OJT generally supports the Company's intention to use modeling credits to stimulate investment of future energy projects, including bonus credits for minimum levels of jobs created in communities. In addition to having these just transition credits in Pueblo County and Routt County, OJT argues the Company should also apply these modeling credits to Moffat County and Morgan County. [182]

212. CEO makes clear that it continues to support a strong commitment to just transition communities and impacted workers. More specifically, CEO recommends the Company provide community assistance payments to Morgan, Pueblo, and Routt Counties, and supports OJT's recommendation that the Company provide community assistance payments to Moffat County for Craig 2, proportional to the Company's ownership share at Craig 2. CEO also recommends the Commission adopt OJT's proposal that directs Public Service to allow just transition communities the option to receive up to one-third of their community assistance payments upfront, to the extent that is allowed by the USA from the 2021 ERP/CEP.[183] CEO argues the statutory just transition requirements and 2021 ERP/CEP USA establish a floor for the Company's just transition obligations and asserts that no party has pointed to any language in the USA prohibiting the Commission from going beyond the obligations in that document.[184]

[181] OJT's SOP at pp. 16-17.
[182] Hr. Ex. 600, Buchanan Answer, pp. 28-29.
[183] CEO's SOP at pp. 19-20.
[184] CEO's SOP at p. 18.

213. Regarding the just transition modeling credits, CEO recommends extending the modeling credits to Moffat County. According to CEO, extending these modeling credits is one way to drive investment to Moffat County to help offset some of the economic loss that the community will experience when Craig 2 retires. CEO asserts that at hearing, Company indicated it would not oppose such an extension of the modeling credits. [185]

214. CEI, Interwest, WRA and SWEEP, Conservation Coalition, CC4CA, and EJC all recommend the Commission eliminate the just transition modeling credits in some way or at least model Phase II portfolios with and without the just transition modeling credits so that the Commission and parties can see the true impact of the just transition modeling credits. For instance, CEI argues the thresholds for the credits—a bidder's estimate of the amount of jobs and taxes—are arbitrary and subject to manipulation. Bidders could *estimate* that their projects would generate more than $4 million in taxes or more than 20 jobs, but they are under no obligation to deliver on those numbers via the final projects. CEI also asserts that the thresholds for jobs and tax revenues needed to qualify for the modeling credits are all but unobtainable for renewable based projects. Further, the credits ignore the incremental benefits of smaller projects or the value that several smaller projects can provide to just transition communities in aggregate.[186]

215. CEI asserts that, under the Company's proposal, the actual incremental cost of utilizing the proposed just transition credits will never be known. CEI references analysis put forth in its Answer that shows ratepayers could pay $4.5 million more for a 50 MW project or up to $32.5 million more for a 300MW project located in a just transition community. CEI asserts these costs could double if such projects also qualify for the more lucrative bonus credits.[187]

[185] CEO's SOP at p. 18.
[186] CEI's SOP at pp. 9-11.
[187] CEI's SOP at p. 10.

216. Interwest raises similar arguments, asserting the proposed just transition modeling credits will skew RFP results to favor utility-owned and fossil fuel generation. According to Interwest, without expanding the just transition modeling credits to other communities, the Company holds a significant structural advantage through its exclusive transmission rights. Without scaling these credits for projects of smaller individual impact, the majority of these credits will likely not apply to renewable facilities.[188]

217. WRA and SWEEP recommend the Commission reduce the scale of the just transition modeling credits by half and direct the Company to model Phase II portfolios both with and without the credits. WRA and SWEEP calculate that the full just transition modeling credits would equate to a discount of 21 to 24 percent, which they argue does strike the right balance between the benefits and the cost to ratepayers. WRA and SWEEP further warn that the just transition modeling credits may signal to developers that they can inflate their bid prices in these regions while remaining competitive in the biding process.[189]

218. Conservation Coalition notes the just transition modeling credits were not contemplated in the 2021 ERP/CEP USA. In contrast, the property tax offset approach was included in the USA and, Conservation Coalition argues, is required by SB 19-236. Conservation Coalition goes on to argue that the just transition modeling credits are arbitrary and that the Company never analyzed their cost impacts. Conservation Coalition asserts that, regardless of intent, the practical effect of the just transition modeling credits will be to incentivize the model to select new gas—even in communities like Hayden that have expressly stated they do not want a new gas plant. [190]

[188] Interwest's SOP at p. 10.
[189] Hr. Ex. 1300, Valentine Answer, p. 79.
[190] Conservation Coalition's SOP at pp. 11-14.

219. In the alternative, Conservation Coalition argues the Commission should at least require the Company to model (1) some portfolios in Phase II with half the dollar amount for the credits, and (2) some portfolios without the just transition modeling credits. Otherwise, Conservation Coalition argues the Commission would *never* understand the cost or resource impact of using these credits.[191]

220. CC4CA argues that if the Commission approves the just transition modeling credits, the credits should apply only to clean resources. Moreover, the Commission should direct Public Service to model all Phase II portfolios with and without the credits, including for Moffat County. CC4CA asserts such information is important to the Commission, Public Service, intervenors, and the public to evaluate the cost and effectiveness of the just transition modeling credits as a just transition tool.[192]

221. EJC argues gas plants should be ineligible for the just transition modeling credits. The EJC supports, however, applying the modeling credits to clean energy resources such as solar, wind, and battery storage. EJC reasons the Commission must apply SB 21-272 for a broader view of just transition and not just consider workforce and economic consideration. EJC notes the Commission must correct historical inequities where possible, provide equity, and minimize impacts and prioritize benefits to disproportionately impacted ("DI") communities. According to EJC, approving a proposal that encourages Public Service to build gas plants in DI communities would flout these requirements.[193]

222. In Rebuttal, Public Service states it needs Commission direction regarding whether the Company should provide community assistance payments based on the accelerated retirement

[191] Conservation Coalition's SOP at p. 16.
[192] CC4CA's SOP at pp. 4-5.
[193] EJC's SOP at pp. 10-11.

of Craig Unit 2. [194] If the Commission directs Public Service to provide community assistance payments for Craig Unit 2, the Company believes that Moffat County should get six years of payments with an offset for new replacement generation and infrastructure, similar to the structure used for Routt County and Morgan County. Public Service calculates the average annual community assistance payment for Craig Unit 2 would be $645,667, for a total of $3,874,000 over the 2029-2034 time period.[195] Public Service clarifies that it is "neutral" on whether to provide community assistance payments for Craig Unit 2, so long as the Commission makes a finding that any estimated tax payments that Public Service makes for these facilities only represent such payments up to the ownership-proportional amount.

223. In contrast to Craig Unit 2, the Company argues against any community assistance based on the early retirement of Craig Unit 1. The Company notes the decision to retire Craig Unit 1 was announced in 2016 to assist with Regional Haze Rule compliance. Public Service notes this announcement was well before the passage of SB 19-236 (with its just transition requirements) and thus argues that Craig Unit 1 is differently situated than all of the other coal units.[196]

224. Except for the possible addition of community assistance payments for Craig Unit 2, Public Service opposes disturbing the community assistance payments agreed upon in the USA.[197] Public Service specifically opposes the recommendation from the Routt County Governments that the Company pay a total of $89 million of combined property tax backfill and direct payments for economic development over a ten-year period for the early retirements of Hayden 1 and Hayden 2. The Company reiterates that Hayden's $16.3 million community assistance payment under the USA is based on replacement tax revenue to the area associated with

[194] Hr. Ex. 117, Ihle Rebuttal, pp. 81-82.
[195] Hr. Ex. 117, Ihle Rebuttal, pp. 82-83.
[196] Hr. Ex. 117, Ihle Rebuttal, p. 81.
[197] Hr. Ex. 117, Ihle Rebuttal, p. 89.

the Hayden units, prior to any offset. According to Public Service, "this value replaces taxes that would have been paid if the generators had operated to the end of their full book lives."[198] The Company asserts that the Routt County Governments' requested $89 million would amount to over $70 million more than the property taxes that Routt County would have received had the Hayden units not been proposed for accelerated retirement.[199]

225. As for the Routt County Governments' request for dedication of real property assets and assurance that the Hayden Station site will be fully remediated of environmental impacts, the Company argues that these proposals "go beyond the scope of this proceeding."[200]

226. Regarding the just transition modeling credits Public Service opposes recommendations to extend the just transition modeling benefits to Moffat County. The Company argues the areas that receive the modeling benefits were the areas where the Company operated coal units that are subject to accelerated retirement under the 2021 ERP/CEP. Public Service asserts it would be inappropriate for the modeling credits to drive generation into Moffat County at the expense of Routt County, Pueblo County, or Morgan County, especially given Tri-State's proposal for new thermal investments in the area.[201]

227. Overall, Public Service stands by its proposal for just transition modeling credits and property tax tail modeling for Pueblo County, Morgan County, and Routt County. Public Service concedes that the just transition credits are not a "perfect" calculation but argues it does not follow that these credits are unnecessary or inappropriate. Public Service urges the Commission to not entertain proposals to develop portfolios with and without the credits.[202]

[198] Hr. Ex. 117, Ihle Rebuttal, p. 86.
[199] Hr. Ex. 117, Ihle Rebuttal, pp. 85-86.
[200] Hr. Ex. 117, Ihle Rebuttal, p. 87.
[201] Hr. Ex. 117, Ihle Rebuttal, p. 85; Public Service's SOP at pp. 22-23.
[202] Public Service's SOP at pp. 22-23.

228. In their SOP, the Pueblo Intervenors reiterate their support for the Company's proposed JTS, which adopts many of the recommendations of the PIESAC Report.[203] In contrast, the Pueblo Intervenors specifically oppose the recommendations to expand community assistance payments based on the Tri-State model. The Pueblo Intervenors argue that the settlement with Tri-State does not provide any authority to modify the terms of the USA, let alone modify the provisions of SB 19-236. The Pueblo Intervenors continue to support the USA but warn that if the Commission orders these types of payments to the other coal communities, then the Pueblo Intervenors should be able to make similar claims pursuant to the Commission's interpretation of the statute and the USA.[204] The Pueblo Intervenors characterize OJT's proposal for community assistance payments to include lump sums as "dangerous." Pueblo argues that a large lump sum could trigger a TABOR event requiring a refund. Having to litigate against even a questionable claim—whether or not the payments in lieu of taxes are actual tax collections—is expensive.[205]

229. The Pueblo Intervenors also support Public Service's position on the just transition modeling credits in that they oppose extending the credits to Moffat County. Pueblo argues that Public Service has a limited amount of time and resources to drive construction of infrastructure into coal communities, and the Company should be focused on the communities in which they have operated coal facilities and with whom they have relationships. The Pueblo Intervenors suggest that the funds Moffat County are expected to receive from Tri-State could be used to provide financial incentives for projects. The Pueblo Intervenors argue that extending the just transition modeling credits will make it an uneven playing field for the other coal communities.[206]

[203] Pueblo Intervenors' SOP at pp. 3-4.
[204] Pueblo Intervenors' SOP at pp. 21-22.
[205] Pueblo Intervenors' SOP at pp. 20-22.
[206] Pueblo Intervenors' SOP at p. 23.

230. Staff supports maintaining community assistance payments for the communities as agreed to in the USA and is not opposed to the Company's ownership-proportional payments for Craig Unit 2. Staff opposes, however, additional community assistance payments because these payments have an affordability impact on all ratepayers, including low-income customers. The Company should instead pursue alternative mechanisms that will prioritize reinvestment in affected communities (*e.g.*, property tax offset incentives, modeling credits, and strong Pueblo, Hayden, and OJT representation in CFFD).[207] Regarding the just transition modeling credits, Staff supports including a Phase II portfolio that excludes the modeling credits. Staff argues that such a Phase II portfolio will help determine the impact of the credits on ratepayers and any potential biases the credits may create.[208]

4. Findings and Conclusions

a. Community Assistance

231. We direct Public Service to provide community assistance payments to Moffat and Craig, based on its ownership interest in Craig Unit 2, consistent with the Company's offer in Rebuttal Testimony and its SOP. Specifically, Moffat County should get six years of payments with an offset for new replacement generation and infrastructure, with the average annual community assistance payment being $645,667, for a total of $3,874,000 over the 2029-2034 time period.[209] We agree with arguments from Moffat and Craig, OJT, UCA, and others that there is little justification for treating Craig 2 differently than Hayden 1 and Hayden 2. The contention that only the operator of a coal plant is responsible for providing community assistance payments is unpersuasive. For the reasons set forth by Public Service, we reject arguments that Public Service

[207] Staff's SOP at p. 29.
[208] Staff's SOP at pp. 11-12.
[209] Hr. Ex. 117, Ihle Rebuttal, pp. 82-83.

should also provide community assistance payments for Craig Unit 1 given that the decision to retire this unit was announced in 2016.

232. With minor exceptions set forth below, we also adopt the Company's position about the level of community assistance payments, including those associated with Craig Unit 2 and Hayden Units 1 and 2, and maintain the basic framework agreed upon in the 2021 ERP/CEP USA.[210] We acknowledge the Routt County Governments and Moffat and Craig did not intervene in the 2021 ERP/CEP and are not part of the USA. Nevertheless, it is our understanding that the community assistance amounts for these communities approximate the replacement tax revenue these communities would have received from Public Service but for the accelerated retirement of the units.[211] The Commission and parties will have an opportunity to finalize the community assistance amounts, as offset by new investments, in the future application proceeding Public Service intends to file. [212] An amount of community assistance that parallels the framework agreed upon in the 2021 ERP/CEP, offset by new investment, is an appropriate path forward that addresses the support of the community, without unnecessarily burdening ratepayers more broadly as it relates to Public Service's ownership interest in these units. To require further assistance would unduly burden the Company, and ultimately ratepayers, and is not supported in this record or by the statutory directives.

233. While we decline to expand the community assistance payments associated with Hayden Unit 1 and Hayden Unit 2, we encourage the other owners in those facilities to contribute their fair share in community assistance payments. We agree with Public Service that a utility's

[210] Commissioner Plant dissents from this point noting that the communities of Hayden and Craig as well as the counties of Routt and Moffat were not parties to the 2021 ERP/CEP and the USA and therefore should not be bound by its agreement on their behalf.

[211] Hr. Ex. 117, Ihle Rebuttal, pp. 85-86.

[212] Hr. Ex. 101, Ihle Direct, Rev. 1, p. 55.

obligation to pay community assistance payments should be based on the utility's proportionate ownership interest. However, just transition communities rely on the full value of the property taxes associated with the facilities, not just the property taxes that Public Service contributes. While our directives are pertinent to requirements of regulated utilities, to further help ensure a just transition, co-owners of the facilities are encouraged to address community assistance payments based on their particular ownership interests. Just as we maintain Public Service has an obligation to Craig as a minority owner, we suggest those with minority positions in Hayden Unit 1 and Hayden Unit 2 have a similar obligation and should honor that obligation to those communities.

234. We do not diminish the impact that the just transition communities face from the early retirement of the coal units, but we agree with Staff that further expansion of the community assistance payments will have affordability impacts on all ratepayers, including low-income customers.[213] The community assistance payments from the Company are directly funded by ratepayers—not Public Service's shareholders. The Commission's approach must balance affordability concerns with the level of community assistance payments. We note that our decisions largely approving the CFFD and adopting additional modeling credits should help drive additional investments to these just transition communities, which appear preferable to limited-duration cash payments.

235. The Commission grants the Pueblo Intervenors' request that the Commission decision quantify the community assistance payments to Pueblo County and the underlying methodology. As set forth in the Company's Direct, and echoed in the Pueblo Intervenors' Answer, pursuant to the approved terms of the 2021 ERP/CEP USA, Public Service will pay to Pueblo

[213] Staff's SOP at p. 29.

County an average annual payment of $16,243,900 for 10 years for a total of $162,439,000.[214] This value is based on the assessed value of Pueblo Unit 3 and includes an annual escalator of two percent and excludes the property tax adjustments from the 2024 special legislative session.[215] These payments are subject to offset from additional investment within Pueblo County, the details of which will be adjudicated in a future proceeding. The Commission acknowledges that Pueblo County reserves its right to argue the two percent escalator is too low, especially if there is a materially high inflation period.[216]

236. Finally, the non-monetary requests from the Routt County Governments appear reasonable, cost-effective methods to help that community achieve a just transition. As such, Public Service shall be required to propose a pathway to the dedication of the Hayden Station Spur Line, the Pumphouse Property, and any unused water rights currently benefiting Hayden Station after the year 2050. This pathway should be explored in the new application proceeding Public Service has committed to file that will finalize the community assistance payments for each community.[217]

b. Just Transition Modeling Credits

237. At the outset, we reiterate that the USA from the 2021 ERP/CEP already contemplates modeling benefits designed to drive new investments to just transition communities. Under this property tax offset modeling approach, all portfolios bear the expected cost of the community assistance payments. Those portfolios that include new investments in the just

[214] Hr. Ex. 101, Ihle Direct, Rev. 1, p. 54; Hr. Ex. 1203, Genesio Answer, p. 3.
[215] Hr. Ex. 101, Ihle Direct, Rev. 1, p. 54; Hr. Ex. 1203, Genesio Answer, p. 3.
[216] Hr. Ex. 1203, Genesio Answer, p. 3.
[217] Regarding the request for incentives or commitments from Public Service for a geothermal unit in Routt County, this issue is more appropriately addressed through the CFFD process. As for the request for a binding commitment to fully remediate all environmental impacts of Hayden Station, such environmental matters are likely outside of the Commission's jurisdiction.

transition communities, however, can deduct from the community assistance costs the anticipated property taxes from the new investments. Thus, the property tax offset modeling approach included in the USA incentivizes the model to select new resources within the just transition communities because these resources would help offset the community assistance costs. Consistent with the USA from the 2021 ERP/CEP, we approve this property tax offset modeling approach for use in the Phase II modeling of this Proceeding.[218] Moreover, Public Service must ensure that the present value revenue requirement ("PVRR") of each portfolio reflects any offset in community assistance payments from new investments. For example, if one of the portfolios includes a new thermal unit located in Pueblo County, that portfolio's PVRR should be reduced by the offset in community assistance payments that the thermal unit would create.

238. In addition to the property tax offset modeling approach, we partly approve Public Service's proposal to expand the modeling benefits beyond what the USA in the 2021 ERP/CEP contemplates via the just transitions modeling credits. As initially proposed, projects located within the just transition communities will receive a base credit of these just transition modeling credits $1.00/kw-month or $2.00/MWh. In addition, projects that create more than 20 long term jobs and that are estimated to provide more than $4 million in annual property taxes will receive an additional bonus credit totally $1.00/kw-month or $2.00/MWh. All told, projects could be eligible for just transition modeling credits of $2.00/kw-month or $4.00/MWh.

239. We share the concerns raised by multiple intervenors that modeling credits of $2.00/kw-month or $4.00/MWh do not strike the right balance between the benefits to just transition communities and the cost to ratepayers. For instance, WRA and SWEEP calculate that

[218] Commissioner Gilman dissents from this point and would have directed the Company to model each of the portfolios without the JTS modeling credits but allow one alternative version of the preferred portfolio to be run with the JTS modeling credits.

a project receiving the full amount of just transition credits would receive a modeling discount of 21 to 24 percent. [219] This significant advantage would be in addition to other advantages such as the transmission capacity that will be made available once the existing coal facilities retire.[220] Given these advantages, we are concerned the full just transition modeling credits could allow developers to inflate the bid price of their projects. To achieve a more appropriate balance, we reject the bonus credits and approve only the base credit of $1.00/kw-month or $2.00/MWh for projects located within just transition communities. Eliminating the bonus credits associated with a bidder's estimate of long term jobs and annual property taxes addresses concerns from parties like CEI, Interwest, WRA and SWEEP, and Conservation Coalition that bonus credits will inappropriately bias the model towards gas generation and are subject to gaming because there is no penalty if a proposed project does not actually achieve the estimated tax or job benefits. The base just transition credit, in contrast, applies equally to all projects types located within the just transition communities.

240. In addition, we agree with CEO, OJT, and Moffat and Craig that the base just transition modeling credits should apply to Moffat County as well as Pueblo County, Morgan County, and Routt County. Extending the just transition modeling credits is consistent with our decision to extend the community assistance payments to Moffat County. As Moffat and Craig note, the just transition modeling credits will help drive additional investment, which would reduce the community assistance payments to Moffat County. In this way, extending the just transition modeling credits to Moffat County is a logical step that could ultimately help offset community assistance payments that Public Service ratepayers would otherwise bear.

[219] Hr. Ex. 1300, Valentine Answer, p. 79.
[220] Interwest's SOP at p. 10.

241. In addition to eliminating the bonus credits, we agree with arguments put forth by Staff, Conservation Coalition, WRA and SWEEP, and others that there should be at least some Phase II modeling that does not incorporate the just transition modeling credits. Public Service chose not to include the just transition modeling credits in any Phase I modeling, nor did the Company provide a robust analysis as to why credits of $1.00/kw-month or $2.00/MWh were appropriate. Without at least some Phase II modeling that excludes the just transition credits, it will be difficult to determine what the modeling credits will actually cost Public Service ratepayers or how the credits impact the selected resources. Moreover, even if the Commission selects a portfolio that includes the just transition modeling credits, requiring three portfolios without just transition modeling credits will lessen concerns that bidders who anticipate receiving just transition modeling credits will inflate their bid prices. Accordingly, we direct Public Service to model three Phase II portfolios without any just transition modeling credits.[221]

242. Recognizing that the modeling credits are just that – credits for the purposes of influencing the economic model – we want to ensure the costs of community assistance payments are accurately portrayed in the PVRR of the Phase II portfolios. For example, if a portfolio does not include any projects within just transition communities, the PVRR of such a portfolio must include the full amount of community assistance payments. In contrast, if a portfolio does include projects within just transition communities, the PVRR of that portfolio must account for how those just transition projects will offset the community assistance payments.

[221] The specific Phase II portfolios that must be run with the just transition modeling credits are set forth below in Section M.

I. CFFD

1. Party Positions

243. Public Service asserts it has seen very few truly innovative technologies bid into recent resource solicitations. The Company argues that as ELCC values continue to decline and the need for clean, medium-to-long term dispatchable generation continues to increase, there must be more diversity in the potential resources in the solicitations. For instance, the Company's Phase I modeling shows that additions of advanced technologies such as geothermal and nuclear significantly reduce the amount of wind, solar, and storage the system needs. Specifically, the modeling estimates that 3,000 MW of advanced technologies replace 11,000 MW of wind, solar, and storage, for a net reduction of 8,000 MW.[222] The Company asserts, however, that these advanced technologies have long-lead times and high upfront investment costs that make it difficult for such projects to arise from the Commission's current ERP processes.

244. To kickstart the development of advanced power generation technologies in Colorado, Public Service recommends the Commission approve the Company's CFFD proposal. Under the CFFD, the Company would conduct a request for information ("RFI") for things like nuclear, advanced geothermal, and thermal plus carbon capture. An advisory board would review responses to the RFI and make the initial determination on whether to fund projects.

245. Under the Company's proposal, the advisory board would consist of one member from the following: Public Service, Staff, UCA, CEO, the OJT, one member from Hayden, one member from Pueblo, and one member from the environmental community. Meetings would be facilitated by an independent facilitator.

[222] *See* Hr. Ex. 101, Ihle Direct, Rev. 1, pp. 66-67, 81-82.

246. Public Service proposes the several customer protections for the CFFD, including that payments to developers are made upon demonstration of action identified in the milestone payment timeline from the RFI response, the Company has a ROFO on any approved project should the developer seek to sell it to a different counter-party or third-party, and if Public Service chooses not select a project through a future solicitation, the developer may sell the project to another off taker but is required to reimburse Public Service for the cost of development provided by Public Service's customers.[223]

247. Public Service promotes the CFFD as one of the tools that can help promote a just transition. The Company that suggests that relying on resources within the RAP to facilitate a just transition is insufficient given property tax payment structures and the reality of workforce needs of most existing technologies. Public Service reasons the CFFD provides an avenue for long lead time advanced technologies that would not be available within the RAP such as pumped hydro, geothermal, nuclear, geologic carbon-capture, and hydrogen. The Company states that it wants to see these types of long-term proposals located in just transition communities and that the CFFD provides a runway of investment opportunities into these communities over a longer time horizon.[224]

248. In response to intervenor feedback, Public Service offers several modifications to the CFFD concept in Rebuttal. To begin, instead of a one-time RFI, the Company agrees with Staff's recommendation that the CFFD be conducted as a rolling solicitation. Among other positive attributes, the Company states this rolling solicitation approach allows parties to remain focused on the JTS Phase II solicitation.

[223] Hr. Ex. 103, Tomljanovic Direct, pp. 54-55.
[224] Hr. Ex. 101, Ihle Direct, Rev. 1, pp. 49-51.

249. Along with the rolling solicitation, Public Service proposes to solicit CFFD proposals twice per year until approximately 2028. While the Company recommends against setting an explicit sunset date for the CFFD, it notes that a 2028 target aligns with the Company's proposal to file the next full ERP in 2028. This would provide a useful check-in point.[225] More specifically, Public Service envisions the advisory board would file a project selection report coming out of each semi-annual meeting with projects selected for funding and the duration of that funding. While Public Service initially sought a budget of $100 million, in Rebuttal the Company states it is "not necessary to have an express budget cap."[226] After the submission of the project selection report, the Commission would have 30 days to review the report and weigh in if it does not support funding any of the projects. If the Commission does not affirmatively act on project recommendations, such proposals would be approved by operation of law.

250. Regarding the advisory board, Public Service recommends adopting CEI's proposal to include a non-voting, technical advisor from either an academic or research institution, but opposes the other various recommendations to expand the advisory board.

251. In addition to the advisory board, the Company continues to believe an independent facilitator would provide a useful role in helping to manage and coordinate meetings and can provide objective minutes from meetings. The Company believes such a role can be filled for a reasonable cost and will confer with the advisory board before selecting an independent facilitator. The Company is also amendable to filing the scope of work for the independent facilitator with the Commission, as it does with other independent consultant roles for transparency, with cost

[225] Hr. Ex. 119, Tomljanovic Rebuttal, p. 16.
[226] Hr. Ex. 119, Tomljanovic Rebuttal, p. 17.

recovery for any independent facilitator being included with other CFFD costs recovered through the ECA.[227]

252. In addition, Public Service clarifies in Rebuttal that project proposals must show a pathway to a viable project suitable for bidding within 10 years of their CFFD submission (not 10 years from the RFI) and cost recovery will only occur after disbursement of funding. The Company further states it is not seeking to earn a return on any of the costs disbursed to developers. Public Service also states that it is willing to provide opportunity for public comment on each semi-annual report.[228]

253. Regarding what technologies are eligible for CFFD funding, the Company supports using the following definition that Staff advances:

> This RFI will consider emerging carbon free electric technologies and long duration storage that enable operation of a carbon-free system. Technologies that will not be considered include commercially mature wind, solar, and short duration storage, and any technology that directly emits carbon dioxide while producing electricity. Examples of eligible technologies include but are not limited to: geothermal, hydroelectric, hydrokinetic, nuclear, renewably sourced hydrogen, long duration storage, and electrical energy from fossil resources with active capture and storage of carbon dioxide emissions that meets EPA requirements.[229]

254. Staff agrees with the Company's shift to conducting the CFFD as a rolling solicitation with semi-annual advisory board meetings, but Staff argues the Commission should maintain the $100 million budget cap. Staff asserts the budget cap is an "important proactive guardrail to reduce the possibility of potentially excessive expenditures."[230] Regarding the advisory board, Staff argues that a large consumer/ratepayer perspective, like CEC, should be

[227] Hr. Ex. 119, Tomljanovic Rebuttal, p. 27.
[228] Public Service's SOP at p. 6.
[229] Hr. Ex. 119, Tomljanovic Rebuttal, p. 21.
[230] Staff's SOP at p. 21.

added. Second, each advisory group member should retain the ability to submit comments to the Commission to explain their voting choice as part of any CFFD funding request.

255. Staff also offers modifications to the Company's plan for the advisory board to file a project selection report after each semi-annual meeting, which would be implemented unless the Commission acts within 30 days. Staff recommends the Commission modify this process to clarify that the Commission retains the right to accept, reject, or modify the results of any advisory group vote prior to Commission approval of CFFD funding. Staff also recommends modifying the proposal for 30-day Commission approval to give the Commission the option to extend the approval timeline to three months with a stakeholder comment period, if the Commission decides more time is needed.

256. Finally, Staff notes that the Company opposes the use of EnCompass modeling to evaluate CFFD technologies. Staff argues the Commission should require at least one modeling study prior to each advisory group vote that includes capacity expansion and production cost models to provide insight for the system value and operation of candidate technologies for CFFD. Staff reasons the CFFD modeling studies will also provide a useful "trial run" that will build experience with emerging technology modeling methods.[231]

257. CEO argues Colorado needs to establish a process for resources with longer-lead-times to incorporate clean resources into the ERP process. CEO states it supports the Company's CFFD proposal if the following five criteria are met: (1) the Company does not earn any return on CFFD dollars, (2) there are two checkpoints on the use of CFFD dollars: approval by the Advisory Board and approval by the Commission, (3) CFFD dollars are equally available to the Company and IPPs (with a firewall at the Company between the team proposing projects

[231] Staff's SOP at p. 23.

and the team deciding which projects receive CFFD dollars), (4) the process for implementing the CFFD, including any by-laws or agreements, is co-developed by the Company and the Advisory Board; (5) any payments under the CFFD are made on a milestone basis for actual costs. [232]

258. CEI generally supports the concept of a CFFD but argues there are too many unanswered questions in the current proposal. CEI asserts that clean firm technologies like next-generation geothermal, green hydrogen, and long-duration energy storage face significant barriers toward deployment based on their high capital costs and long lead times, and a mechanism like CFFD can reduce the risk for innovative clean firm technologies. CEI raises numerous concerns with the Company's current approach, however, including concerns that the Company will be biased towards its own projects, no IPP representatives would be included in the advisory board, the advisory board would not have access to all CFFD bids but would only see the ones the Company selected to advance, and the Company has not committed to computer-based modeling to evaluate potential long-term costs and benefits of the various technologies. Ultimately, CEI recommends the Commission direct Public Service to include, in a separate application, proposals to better standardize bids, ensure neutrality between Company-owned and IPP projects, and methodologies and criteria for evaluating proposals.

259. Alternatively, if the Commission does move forward with the Company's CFFD proposal in this proceeding, CEI argues the Commission should require that (1) all bids are presented to the advisory board, (2) the advisory board includes broader representation, including from the IPP community, (3) that any advisory board member, including the Company, be

[232] CEO's SOP at p. 27.

prohibited from voting on a project proposal that it owns equity in, and (4) that the Commission have final approval authority over any CFFD project.[233]

260. WRA and SWEEP largely mirror CEI's position. WRA and SWEEP support mechanisms that address barriers to the development of carbon-free firm resources, but they assert the Company's CFFD proposal could fund projects that are not carbon-free, does not include transparent evaluation criteria or a transparent advisory committee and approach, and includes a cost recovery approach that prematurely puts more risk on ratepayers.[234]

261. WRA and SWEEP recommend requiring Public Service to refile the CFFD as a standalone application. They suggest Public Service could still proceed with an RFI and then submit an application to the Commission providing the results of the RFI and seeking approval of any proposed CFFD Portfolio.

262. In the alternative, if the Commission moves forward in this Proceeding with the Company's proposed CFFD, WRA and SWEEP recommend several modifications, including the following: require the CFFD Portfolio solely consist of technologies that provide for carbon-free power generation or storage; require the Company to file the draft RFI with the Commission for approval, prior to issuing the RFI; require the Company to provide all parties with all RFI responses, even for projects that are not selected by the advisory board; establish a process for parties and stakeholders to comment on CFFD portfolios proposed by the advisory board, prior to the Commission issuing a decision on the CFFD portfolio.[235]

263. Conservation Coalition opposes the CFFD and recommends the Commission reject it. While CFFD acknowledges that promoting innovative, zero-emissions technologies is a worthy

[233] CEI's SOP at p. 22.
[234] WRA and SWEEP's SOP at p. 24
[235] WRA and SWEEP's SOP at p. 25.

goal, Conservation Coalition asserts its many flaws warrant rejection. According to Conservation Coalition, these flaws include that Public Service never submitted a draft RFI for the CFFD for parties to review; there are no metrics for comparing responses to the RFI; the Company has not committed to EnCompass modeling of the CFFD projects; the Company has not committed to compare RFI responses to other technology types, including conventional wind, solar, and storage;[236] the Company has not mitigated the risk that projects are selected for the CFFD at one price, and then bid into a RFP at a much higher price; and there is no guarantee that customers will receive any benefit in return from the CFFD funds.[237]

264. In the alternative, if the Commission approves the CFFD, Conservation Coalition recommends several changes. These changes include requiring public comment and Commission approval before any ratepayer funds are committed to any CFFD projects; requiring EnCompass modeling of a project before it can receive CFFD funding; comparing each CFFD project to the least-cost portfolio of conventional technologies; and requiring responses to RFIs be made available to parties to this Proceeding subject to confidentiality protections.

265. CEC opposes the CFFD, asserting that with the massive scale of the costs at issue in this Proceeding and the unproven status of advanced technologies, the CFFD is an imprudent use of ratepayer funds. Instead, CEC argues the market should continue to bear the costs necessary to develop these speculative technologies to shovel-ready status.

266. CC4CA's position is similar to CEI, WRA and SWEEP. CC4CA argues the CFFD is incomplete and lacks important details, so CC4CA recommends the Commission require the Company to present the CFFD for approval in a standalone application. CC4CA's specific

[236] Conservation Coalition opposes the underlying premise of the CFFD that customers should fund the pre-development of certain technologies regardless of whether those projects are—or ever will be—more cost-effective than other technologies.

[237] Conservation Coalition's SOP at pp. 17-18.

proposed modifications include adding two representatives to the advisory board—one from a community that seeks 100 percent renewable electricity by 2050 and one from a large commercial and industrial customer with the same or similar goal; requiring all advisory board members to disclose potential conflicts; and prohibiting advisory board members from voting on any RFI response in which the member has a conflict of interest. CC4CA further recommends that the Commission delay a decision on the proposed cost recovery mechanism to a future application or until after RFI responses are received.

267. CRES/PSR similarly request the Commission deny or defer consideration of the CFFD. They further recommend the Commission outright deny proposals to pursue or explore nuclear energy, carbon capture and storage, or hydrogen-based power generation.

268. The EJC recommends the Commission modify the CFFD so that (1) Public Service cannot provide preliminary funding to specific nuclear, carbon capture and storage, and hydrogen projects; (2) the advisory board is more inclusive; and (3) all parties have an opportunity to comment on the Company's funding proposals. Regarding carbon capture and storage, nuclear, and hydrogen technologies, EJC asserts it is improper for Public Service's ratepayers to provide preliminary funding for these types of expensive and uncertain projects. Similar to CEC, EJC reasons the private market should shoulder the costs of developing these technologies to the point that they are commercially available. As for the advisory board, EJC urges the Commission to include a more diverse range of Pueblo community members as well as non-governmental and non-state agency members that represent Public Service ratepayers.

269. OJT generally supports the CFFD concept but argues the advisory board should have representatives from all transition communities, including Morgan County as well as Moffat County.

270. Moffat and Craig support the CFFD proposal but argue the advisory board should be expanded to include one member from Moffat County and one member from Routt County. This modification would create a nine-member advisory board with more diverse coal community viewpoints.[238]

271. The Pueblo Intervenors support the CFFD as proposed, reasoning that many of the advanced technologies, including long duration storage, hydrogen, enhanced geothermal, and advanced nuclear are not yet "mature" in the market and will likely not be during this RAP for the period 2024 through 2031. The Pueblo Intervenors argue that coal communities such as Pueblo need an opportunity to attract these types of investments.[239] The Pueblo Intervenors assert the CFFD "provides an opportunity for Pueblo to be the location of advanced clean technologies including geothermal, hydrogen and yes, possibly advanced nuclear."[240] According to the Pueblo Intervenors, adoption of the CFFD is important to the workers at Pueblo Unit 3 and the Pueblo community because it will provide incentives for not only the Company but IPPs to develop pans and projects for advanced clean energy projects beyond the RAP.[241]

2. Findings and Conclusions

272. At the outset, we find there is broad party support for the CFFD concept, although most parties assert there are significant flaws in the current proposal such that a standalone application proceeding is necessary before allowing the CFFD to proceed. We agree with numerous intervenors who acknowledge the need for a mechanism to address barriers to the development of carbon-free firm resources and approve the CFFD concept. In addition, consistent with testimony from the Pueblo Intervenors, we see the CFFD as another potential mechanism that

[238] Moffat and Craig's SOP at pp. 26-27.
[239] Hr. Ex. 1200, Shaw Answer, p. 15.
[240] Hr. Ex. 1202, Swearingen Answer, p. 15.
[241] Hr. Ex. 1204, Arnold Answer, p. 9.

could help drive new investment in coal transition communities. Indeed, the Routt County Governments indicate their community is uninterested in a gas plant to replace Hayden 1 and Hayden 2, but they expressly request Public Service investigate the feasibility of geothermal generation.

273. The Commission disagrees with proposals from CEI, CC4CA, and WRA and SWEEP to require the Company to file a separate Application proceeding to launch the CFFD. Many of the concerns intervenors raised can be addressed through the advisory board process or decided here. For instance, the precise wording of the RFI and how the costs, benefits, and feasibility of the proposed projects are measured can be left to the advisory board. Given the developmental nature of CFFD projects, it is unlikely the parties and Commission could reach a standard method for evaluating all CFFD projects in advance, even if the Commission directed a standalone application proceeding.

274. Accordingly, we approve the CFFD process as set forth in the Company's Rebuttal, subject to several modifications. First, Public Service's argument that a budget cap is no longer necessary because the CFFD solicitation is rolling is unpersuasive. We agree with Staff that the $100 million budget cap serves as an important proactive guardrail. Although Public Service may make an appropriate request to expand this budget cap if necessary, launching this novel process with no cap on the amount of ratepayer funds is untenable.

275. The Commission also agrees with Staff's proposed changes to the approval process. We clarify that the Commission retains the right to accept, reject, or modify the results of any advisory group vote prior to approval of CFFD funding. The Commission also has the option to extend the approval timeline to an additional three months with a stakeholder comment period, if we decide more time is needed. On this point, we preemptively extend the 30-day period to act on

a project selection report to 60 days. The additional time is warranted given the Company's commitment to provide an opportunity for public comment on each semi-annual report. The additional time is also valuable given the existing demands on the Commission's time and resources. Conversely, it is unclear why approving CFFD funding would be an urgent matter given how the CFFD process is designed to address long lead time projects.

276. The Commission disagrees with the recommendations from Staff, Conservation Coalition, and other parties that the Company be required to conduct EnCompass modeling prior to any CFFD project receiving funding. Although some advisory board members may decline to support a particular project if there is not computer-based modeling, we agree with Public Service that it would be inappropriate for the Commission to mandate EnCompass modeling work for each and every project. The Phase I EnCompass modeling conducted in this Proceeding already shows the value of long-duration energy storage and the fact that relatively small amounts of geothermal or nuclear energy can replace large amounts of wind, solar, and four-hour storage. It is possible that certain CFFD projects may not allow for much more than this generic modeling that has already been conducted. For example, if a CFFD project requested payments to drill geothermal test wells, additional computer-based modeling might not help evaluate the project given fundamental uncertainties about its feasibility.

277. Consistent with CEO's position, we expressly require the process for implementing the CFFD, including any by-laws or agreements, be co-developed by the Company and the advisory board. As part of the formation of the CFFD by-laws or agreements, the advisory board should consider how to mitigate risk that Company-backed CFFD projects will receive preferential treatment. For instance, the advisory board should consider proposals from CEI and others that any advisory board member, including the Company, be prohibited from voting on a project

proposal that it owns equity in. While we stop short of adopting CEI's proposal here, we do endorse the general principle from CEO that CFFD dollars be equally available to the Company and IPPs, with a firewall at the Company between the team proposing projects and the team deciding which projects receive CFFD dollars.

278. In addition, the advisory board shall develop regular reporting requirements for any project that receives CFFD funding. Even though every CFFD project may not be successful, every project may succeed in uncovering valuable information regarding the technology, concepts, and feasibility. To ensure CFFD funding is as useful as possible for ratepayers, the advisor board shall require projects to provide regular reporting including at a minimum what the CFFD money was spent on, why the project ultimately failed or succeeded, and anything learned more generally about the technology.

279. We also agree with the concerns raised by CEI and other intervenors regarding the ability to access the responses to the RFI. CEI asserts the advisory board would not have access to all CFFD bids but would only see the ones the Company selected to advance. We direct the Company to provide all RFI responses to the advisory board, subject to advisory board members executing standard non-disclosure agreements. The Commission acknowledges that some developers may be more hesitant to respond to the RFI if certain information will be shared with the entire advisory board. Nevertheless, this is an appropriate safeguard given developers could receive ratepayer funds.

280. The Commission approves the Company's request for an independent facilitator, with one caveat. The costs of the independent facilitator shall count against the $100 million CFFD budget. This will incentivize Public Service to incur only those costs for an independent facilitator that are necessary.

281. As for the advisory board, we agree with requests from various intervenors to expand its make up. The increased representation will help further ensure that CFFD funds are being allocated appropriately, and with the independent facilitator, the additional administrative demands should be manageable. Specifically, we adopt Staff's recommendation to include a large consumer/ratepayer perspective, like CEC; CEI's recommendation to include a representative from the IPP community; Moffat and Craig's recommendation to include a representative from Moffat County; and OJT's recommendation to include a representative from Morgan County. Thus, the advisory board would consist of one voting representative from the following: Public Service, Staff, UCA, CEO, OJT, the Hayden community, the Pueblo community, the environmental community, a large consumer/ratepayer perspective, the IPP community, Moffat County, and Morgan County.

282. Except for the modifications discussed above, we approve the Company's CFFD proposal as set forth in the Company's Rebuttal. This approval includes the 10-year pathway to Phase II competitive solicitation (*i.e.*, project proposals must show a pathway to a viable project suitable for bidding within 10 years of their CFFD submission); any cost recovery occurs only after disbursement of funding; confirmation of the Company's position that it will not earn a return on any of the costs disbursed to developers; and adoption of Staff's definition of CFFD-eligible technologies.

283. We acknowledge this CFFD process is novel and—despite the additional guardrails adopted here—presents certain risks, including that it is possible for the CFFD funds to not result in cost effective resources deemed prudent to pursue. On balance, however, we find the promises of the CFFD outweigh the risks and could have lasting future benefits. As detailed by Public Service, the Pueblo Intervenors, and others, ideally the CFFD will provide the necessary runway

for the development of advanced technologies that both facilitate the goal of 100 percent clean energy and help ensure a just transition.

J. Resource Adequacy

284. Pursuant to the 2021 ERP/CEP USA, Public Service conducted a "best practice" review of current reliability planning practices.[242] Based on this review, the Company retained Energy + Environmental Economics ("E3") to conduct a resource adequacy ("RA") study ("RA Study"),[243] the main outputs of which are the planning reserve margin ("PRM") and effective load carrying capability ("ELCC") values for each resource type. E3 designed the RA Study around a loss of load expectation ("LOLE") of 0.1 days per year, which is consistent with historical Company practice and with those of many utilities and RTOs around the country.[244]

285. The RA Study differs from that conducted in support of the Company's prior ERP in three ways. First, it utilizes ELCCs for all resources, including thermal resources, which in previous ERPs have been accredited at their net dependable capacities. This change puts all resources on a level footing and shifts the interpretation of the PRM from one based on *installed capacity* to being based on the quantity of *perfect capacity* (*i.e.*, not subject to planned or unplanned outages or resource availability) needed to achieve the reliability target. The Company notes that this accounting change has the effect of reducing the reported PRM since a smaller number of perfect resources can provide equivalent reliability as a larger number of installed but imperfect resources.

[242] Hr. Ex. 102, Att. JTL-1.
[243] The RA Study is Att. ZM-1 to Hr. Ex. 109, Ming Direct.
[244] Table ZM-D-2 on p. 15 of Hr. Ex. 109 presents a list of utilities, RTOs and RA programs using a 0.1 LOLE standard.

286. The second difference between the RA Study in this case and that of prior ERPs is that it developed seasonal PRM and ELCC values rather than annual values. The Company explains that this practice:

> …recognizes that reliability risk is increasingly occurring in both the summer and the winter due to growth in winter loads driven by the electrification of building heating and that many resources (in particular wind and solar) have different availabilities at different times of year due to seasonal availability factors. Therefore, this study separates the year into two seasons, summer (May to October inclusive) and winter (November to April inclusive) and calculates "seasonal" PRM values as the quantity of required perfect capacity to reliably serve peak load in each season. It also calculates seasonal ELCC values as the contribution of each resource toward each season's PRM.[245]

287. The final difference in the RA Study submitted in this Proceeding regards the representation of available market purchases from neighboring utilities. In prior RA studies, the Company made assumptions that neighboring utilities would comply with resource adequacy requirements in their future resource plans, such that the availability of power purchases was a modeling output based on this assumption. In contrast, the RA Study submitted here makes no assumptions about resource adequacy, but bases the availability of market power purchases on the historical average of available purchases during the times when energy is most needed. The Company explains that this change is driven by the recognition that loads and resources in neighboring utilities are increasingly uncertain and are a domain over which the Company has no control. The Company presents this change as a more conservative approach to limit its exposure to the risk that neighbors are unable to fulfil their RA requirements or that market purchases may be extremely costly during periods of scarcity and asserts that this practice is common across many utilities in the Western Interconnection.[246]

[245] Hr. Ex. 109, Ming Direct, p. 19.
[246] Hr. Ex. 109, Ming Direct, pp. 19-20.

288. The Company contends that its RA Study represents a substantial step forward in the development of the PRM and ELCCs and a substantial step toward rectifying Colorado's resource adequacy concerns over the medium- and long-term. It urges the Commission to approve it for use in both the Base and Supplemental RFPs.[247]

1. Considering Wholesale Market Membership in the RA Study

a. Party Positions

289. UCA argues that since the Public Service is required by SB 21-072 to join a regional market by 2030, the Company's RA modeling should include assumptions about the future impact of joining a market. UCA notes that the larger region encompassed by a market will create a more diverse load (utilities peaking at different times) and will reduce transmission charges, meaning that market purchases will be more economical. UCA contends that market participation will likely reduce the needed PRM and will also change ELCC values.[248]

290. UCA rejects the Company's contention that it is hard to model the impact of new transmission resources on RA due to uncertainty regarding the generating resources accessed by a new line, stating that transmission and remote resources "can be treated in a similar way as uncertainty is already modeled in RA studies."[249]

291. Conservation Coalition expresses concern that Public Service's proposals for Phase II modeling reflect neither the Company's proposed participation in SPP Markets+ nor the statutory requirement to join an RTO or ISO by 2030. Conservation Coalition argues that the Commission should require the Company to update its modeling for the supplemental RFP to reflect any data the Company possesses regarding effects on curtailments and market purchases

[247] Public Service's SOP at p. 22.
[248] UCA's SOP at pp. 14-15.
[249] UCA's SOP at pp. 15-16.

and sales. Conservation Coalition further criticizes the Company's proposal to model all Phase II portfolios assuming that it does not join an organized wholesale market ("OWM") by 2030. Conservation Coalition suggests that the Company's justification that it doesn't not know what values it would use to model joining an OWM as no different than claiming that it should assume a cost of $0/MMBtu for gas simply because it doesn't know what the gas price will be in 2030. Conservation Coalition notes that there is uncertainty associated with virtually every variable used in EnCompass, and that making reasonable estimates of uncertain values is inherent in all modeling. Conservation Coalition argues that there is no reason to treat the impacts of joining an OWM any differently than every other uncertain modeling input.[250]

292. Conservation Coalition contends that the Company's hearing testimony that joining a full OWM would have no impact on the Company's modeling was directly controverted by supplemental direct testimony in which the Company states that joining an OWM would "reduce PRM requirements and potentially boost ELCC values, leading to less resource need."[251] Conservation Coalition notes that reduced capacity requirements and reserve sharing are some of the primary rationales for joining an OWM. On this point, Conservation Coalition cites the 2021 Siemens study conducted for the Commission as further evidence that joining a full OWM would reduce capacity needs. Conservation Coalition contends that this has important implications, as not modeling the impacts of OWM membership will result in the Company procuring excess resources. Conservation Coalition contends further that beyond the potential impact of such modeling in this Proceeding, there is value in modeling participation in an OWM to gain insight into the benefits of OWM membership. It argues that "if [Public Service] never analyzes the

[250] Conservation Coalition's SOP at pp. 27-28.

[251] Conservation Coalition's SOP at pp. 28-29 (quoting Hr. Ex. 111, Landrum Supplemental Direct, Rev. 1, pp. 86-87) (internal quotations omitted).

potential benefits of joining a RTO/ISO, [Public Service] may never join a RTO/ISO, because it will not have examined the benefits."[252] Conservation Coalition therefore recommends that in both the base and supplemental RFPs, at least one portfolio should assume that Public Service joins an OWM by 2030, and recommends that SPP's Western RTO be used as a proxy. Conservation Coalition recommends that at a minimum, the Commission should order the Company to model at least one portfolio for the supplemental RFP that assumes the Company joins an RTO/ISO by 2030, and to have a stakeholder process beforehand.[253]

293. Although CEO's answer testimony was critical of the Company for failing to address in its Supplemental Direct Testimony the impact of joining a wholesale market on resource adequacy (PRM, ELCC and resources selected for portfolios), its SOP comments related to the matter are limited to a note that CEO opposes the Company's plan to join Markets+ until the Commission has more information about the impact of joining an OWM. CEO further notes that it supports revisiting this issue in the supplemental RFP once more information on market participation is available.[254]

294. The Company addresses party criticisms that the RA Study fails to reflect participation in an OWM by claiming that there currently is no information on how such participation would impact the PRM and ELCC values, and so any change to the 2024 RA Study values would be speculative at this time. The Company notes that new market entrants are required to bring resources sufficient to meet their load (including reserves) so that any suggestion to reduce

[252] Conservation Coalition's SOP at p. 29.
[253] Conservation Coalition's SOP at pp. 28-29.
[254] CEO's SOP at pp. 22-23. Commissioner Gilman's suggestion to include additional information about Markets+ participation in the Supplemental RFP is found in Hr. Tr. June 13, 2025, p. 224:11-17.

the PRM and ELCC values now could limit the Company's ability to enter into a market in the future.[255]

b. Findings and Conclusions

295. Absent a finding by the Commission that doing so would be contrary to the public interest, the Company must join an OWM by 2030. We agree with intervenors that joining an OWM would likely exert downward pressure on the Company's PRM while simultaneously increasing the ELCCs of some resources. While we find it essential that the Company's RA studies reflect OWM ownership as soon as possible, there is no evidence in the record indicating specifically what assumptions the Company should use regarding which OWM membership the Company should model, nor the specific impacts that would result from that membership. Given the fact that regional markets are still developing in the West, it would be difficult to confidently determine what assumptions to use in time for the supplemental RFP. Accordingly, the Commission finds that modeling OWM membership in RA studies will remain premature until the 2028 ERP, and we will not therefore require such modeling for either the base or supplemental RFPs in this Proceeding.[256]

296. However, we find that by the time the Company files an ERP, it is already too late to make material changes to the RA Study that are identified during the proceeding. Requiring a revised RA study in a Phase I decision would unduly delay the subsequent solicitation. Our experiences in this Proceeding and its predecessor have demonstrated that, given the leverage that the results of RA studies have in both identifying resource need and the capabilities of the various resource types to satisfy that need, it is necessary for RA modeling parameters and methodologies

[255] Public Service's SOP at p. 21.

[256] Commissioner Gilman dissents on this point and would pursue a process to incorporate OWM assumptions into the supplemental RFP.

to be litigated separately from and well in advance of the ERP proceeding in which they are to be applied so that significant issues can be identified and fully rectified in advance of the Phase II solicitation. Accordingly, we direct the Company to file an application proceeding to litigate RA study assumptions and methodologies no later than March 31, 2027. A filing by this date should allow the Commission to arrive at a decision by the end of that year, providing sufficient time for the Company to conduct the RA study and apply its results to the 2028 ERP.

2. Reliability Rubric

a. Party Positions

297. Following the preliminary creation of the Phase II portfolios, Public Service proposes running each portfolio through a stress test using extreme summer and winter scenarios. If the portfolios indicate any non-zero amount of unserved energy or ancillary service violations under these extreme conditions, the Company proposes to conduct a series of steps to add resources until no unserved energy remains. Only after passing this rubric would the Company consider it to be reliable.[257]

298. In Rebuttal, Public Service agrees to present the results of portfolios that do not initially pass the rubric tests, along with the final resource portfolio determined after applying the corrective actions outlined in the rubric. For the portfolios that initially failed the extreme weather tests, the Company would show the capacity expansion plans (*i.e.*, bids in the portfolio) and the amount of expected unserved energy ("EUE") or ancillary service violations for that portfolio. The Company opposes all other suggested changes to the reliability rubric.

299. CEI criticizes the Company's refusal to demonstrate how its reliability rubric would affect the generic Phase I portfolios, stating that as a result, neither stakeholders nor the

[257] Hr. Ex. 101, Att. JWI-2, Vol.2 - Tech. Appendix, Rev. 2., pp. 233-234.

Commission have visibility into how the rubric would impact the resources required to meet the reliability standard.[258] CEI argues it is essential for the Commission to establish clear parameters for the presentation and application of the reliability rubric in Phase II and recommends the Commission direct the Company to present an economic analysis in its 120-Day Report alongside the reliability results, including the marginal cost of additional resources needed to eliminate the last increment of unserved energy and a comparison to reasonable Value of Lost Load ("VOLL") estimates from industry literature. CEI argues further that the Company should be required to report the magnitude and duration of reliability events, not just the occurrence of unserved energy so that the Commission can assess whether less costly solutions might be appropriate. Finally, it argues the Company should model and present results both with and without application of the most stringent reliability requirements, so that the Commission can clearly understand the incremental costs and benefits of different approaches to reliability. CEI claims these steps will help ensure that the plan adopted is economically rational.[259]

300. CEO and WRA and SWEEP ask that the Commission require Public Service to document and provide as part of its Phase II report the initial portfolio results in terms of the incremental resource additions and PVRR added to that portfolio during each step of the reliability rubric.[260]

301. Staff recommends the Company keep Staff apprised of any changes to the proposed reliability rubric before and during the actual modeling of bids in Phase II. This ensures that Staff is able to confirm that Phase II modeling assumptions are in line with what is approved in a Phase I decision. Similar to other parties, Staff also expresses concern that the Company has not

[258] CEI's SOP at pp. 22-23.
[259] CEI's SOP at p. 24.
[260] CEO's SOP at p. 8; WRA and SWEEP's SOP at p. 29.

applied the extreme weather test to the generic Phase I portfolios, stating that it is unclear how the testing of portfolios will play out in Phase II.[261]

b. Findings and Conclusions

302. We generally believe that any approach that is structured to completely ignore economic issues under extreme assumptions is problematic. As a state and a society, we accept the fact that it may be prohibitively expensive for a utility to attempt to provide perfect reliability. Accordingly, we agree with the parties who addressed this issue that it is vital that the Company provide detailed information on the impact of the reliability rubric on the Phase II portfolios. While we note the importance of addressing reliability in the context of modeling, we also recognize that the Company has many processes to continue to ensure reliability in extreme events. Modeling exercises through the ERP in no way prohibit those endeavors, rather they ensure as they have for decades appropriate proactive measures can be taken based on the best information available. Such pre-planning can help create better cost-effective solutions to known stresses in coming years.

303. We therefore adopt CEO's suggestion and direct Public Service to provide—in addition to the information the Company committed to provide in Rebuttal Testimony—information about each reliability event that causes a portfolio modification due to the reliability rubric. This must include identifying the added resources, the change in portfolio PVRR, the magnitude, duration and EUE of each event, and a comparison of the cost of serving otherwise unserved energy. This information must be presented as part of the 120-Day Report.

[261] Hr. Ex. 2604, Abiodun Answer, pp. 14-18.

304. Further, as recommended by Staff, we direct the Company to keep Staff, the IE, and as appropriate other parties apprised of any modifications to the impacts of the reliability rubric as best as reasonably possible through both the base and supplemental RFPs.

305. To be clear, we make these changes not because we are concerned the Company's proposed rubric will produce unreliable results, but because there may be less expensive ways to plan ahead based on best information for the Company to continue to maintain reliability. The modifications we direct here provide additional transparency about the reliability rubric's impacts on costs.

3. Economic Metrics in the Assessment of Resource Adequacy

a. Party Positions

306. In response to party advocacy to the contrary, the Company thoroughly opposes the notion that economic considerations (such as VOLL) should be included in RA analysis, noting that the 0.1 LOLE standard it applies is accepted practice and current standard in Colorado and around the country. The Company contends that the use of economic reliability as a standard is "functionally non-existent."[262]

307. CEI asserts that the Company's RA Study suffers from several weaknesses that limit its usefulness. Chief amongst these, according to CEI, is the study's failure to consider economics in the analysis, amounting to requiring "perfect insurance" in that the reliability rubric seeks to eliminate all unserved energy regardless of cost without considering whether the incremental benefit of doing so exceeds its cost. CEI is further critical of the Study's failure to distinguish between brief outages affecting a small number of customers and large-scale, multi-hour blackouts. The absence of this distinction leaves decision makers without meaningful

[262] Public Service's SOP at p. 20.

context and fails to consider whether low-cost solutions such as DR, VPPs or targeted reliability programs could address short-duration or low-magnitude reliability gaps.[263]

308. CRES/PSR argues that LOLE alone is an insufficient metric to gauge resource adequacy. CRES/PSR contends that VOLL should supplement LOLE and be used to justify, prioritize or rank transmission or other reliability portfolio investments in Phase II. CRES/PSR contends that the failure to consider VOLL has led to an estimated $1.2 billion in ratepayer costs in 2024, based on Staff's finding in Proceeding No. 24I-0394E (the Commission's investigation into Public Service's Electric System Outages) that system average outage duration that year was 350 minutes. CRES/PSR emphasizes that the Staff report in that proceeding found that customer outages were rarely due to transmission and never due to resource inadequacy, but in almost all cases due to events on the distribution network.[264]

309. CRES/PSR contends that supplementation of the LOLE metric is neither novel nor likely to cause reduced reliability, as the Company argues. For support, CRES/PSR cites a 2024 Energy Systems Integration Group ("ESIG") report detailing the growing obsolescence of single-metric RA analyses and noting the emerging adoption of multi-metric approaches. CRES/PSR also points out that the same conclusion was recently drawn by the North American Electric Reliability Corporation's Probabilistic Analysis Working Group.[265] CRES/PSR contends that these conclusions by NERC and ESIG contradict the Company's "mischaracterization" of economic considerations as an either-or tradeoff that lowers reliability. CRES/PSR also argues that the VOLL is used in assessing non-wires alternatives and undergrounding in both the ongoing Distribution System Plan Proceeding and the company's Wildfire Mitigation Plan. Accordingly,

[263] CEI's SOP at pp. 22-24.
[264] CRES/PSR's SOP at pp. 19-21.
[265] CRES/PSR's SOP at p. 21.

CRES/PSR recommends that VOLL should be considered to justify, prioritize, or rank transmission or other reliability portfolio investments and projects.[266]

b. Findings and Conclusions

310. We find that CRES/PSR and CEI argue convincingly that an evaluation of resource adequacy that considers only LOLE provides an incomplete picture of a system's reliability needs, limiting transparency into the nature of reliability events and limiting the Commission's ability to select the resources that best match the reliability need.[267] We agree with these parties that the Company has provided no information on the magnitude or duration of the modeled reliability events that contribute to the proposed PRM, so neither the Commission nor the parties can have insight into whether the appropriate solution to a reliability event is an additional 200 MW CT, enhanced incentives to stimulate 500 kW of additional load flexibility, or to simply weather the consequences of a small amount of projected unserved energy.

[266] CRES/PSR's SOP at pp. 22-24.

[267] We note the Company's RA Study itself cites a report by the Energy Systems Integration Group ("ESIG") that explicitly states the LOLE metric is no longer an adequate measure of system reliability: "In addition, the reliability events are now more varied; therefore, understanding the size, frequency, duration, and timing of potential shortfalls is essential to finding the right resource solutions. LOLE is an inadequate metric in a world of more varied shortfall events because it provides limited information on shortfall events' size and duration. This makes it difficult to know the true impact of potential shortfalls and nearly impossible to determine the types of resources necessary to reduce the number of shortfalls." (ESIG, "Redefining Resource Adequacy for Modern Power Systems" (2021), p. 10).

311. CRES/PSR admitted an ESIG report that lends additional credence to the notion that LOLE must be supplemented:

> … Some grid operators are already considering changes. PJM, the Southwest Power Pool (SPP), and the Mid-continent Independent System Operator (MISO), for example, are exploring whether to move from LOLE to expected unserved energy (EUE) as the resource adequacy criterion used for calculating capacity accreditation. The Electric Reliability Council of Texas (ERCOT) and the Northwest Power and Conservation Council (NWPCC) are proposing multi-metric criteria for future resource adequacy planning. … As a society, including planners, regulators, policymakers, and ratepayers, we have to decide how much we will pay for reliability and when to accept that there will be times—albeit rare—when the system cannot serve the load. This policy or regulatory decision shapes our resource adequacy criteria, determining the level of supply in which we are willing to invest and recognizing that mitigating all risks on the system may not be worth what that would cost. A resource adequacy criterion does not just measure risk but must also inform actionable investment decisions. Planners and regulators must weigh different types of investments to improve resource adequacy against a growing set of planning objectives, including costs for ratepayers, environmental objectives, and other options to improve reliability, such as distribution-level outages, transmission stability, or cybersecurity. Different options also come at different costs, which requires decision-makers to evaluate these trade-offs in a consistent manner. Effective multi-metric criteria should enable planners and regulators to delve beyond frequency metrics, like LOLE, to more fully characterize system reliability and better inform these investments.[268]

312. The authors of this report subsequently draw the following conclusion: "In short, using loss-of- load expectation as the sole resource adequacy criterion represents only a single dimension of risk. The full detail of the system's risk profile cannot be described by a single number; it needs to be supplemented…."[269]

313. The authors discuss several justifications for this among which are that 1) a single-metric criterion provides inadequate differentiation among the size, frequency, duration, and timing of shortfalls and thus fails to reflect nonlinear damages; and 2) as more energy

[268] Hr. Ex. 1602, Att. JG-3, pp. 4-5.
[269] Hr. Ex. 1602, Att. JG-3, p. 10.

limited resources are added to electric systems, the types of reliability events are far more diverse than they've been historically, and the rough proportionality between LOLE and EUE that existed historically becomes a less accurate assumption.

314. Given the above, we find the Company's opposition to the inclusion of economic considerations in the assessment of resource adequacy to be neither well-founded nor supported as an industry best practice going forward. The absence of economic considerations in assessing resource adequacy can leave the Commission blind to potentially large discrepancies between reliability events and the type and magnitude of the resources identified to address them. Accordingly, in conjunction with the Resource Adequacy Application filing discussed above, we direct the Company to propose a multi-metric approach to resource adequacy, including at minimum LOLE and EUE (or EUE normalized to annual consumption) as the target metrics. The Company shall retain the 1-day-in ten-years metric for LOLE. For EUE, the Company shall conduct research on existing and emerging practices for the use of EUE in multi-metric RA frameworks and shall propose and justify an EUE target based on this research.

4. Modeling of Market Purchases in the RA Study

a. Party Positions

315. The Company defends its practice of limiting market purchases in the RA Study to the average availability of purchases during high risk hours in recent years, and is critical of party suggestions that it should model neighboring systems to determine availability of purchased power, noting that loads and resources of these systems are increasingly uncertain, making any modeling attempt "an exercise in speculation." The Company notes further that its ability to import power is limited by transfer capacity, further limiting its ability to rely on its neighbors in times of

need. It contends that no party presented compelling testimony supporting greater reliance on imports and warns that such reliance could have implications for future reliability.[270]

316. UCA contends that market representation in the RA Study should reflect historical purchases as modified by the addition of new transmission interconnections or OWM market entry.[271]

317. Conservation Coalition is critical of the Company's representation of market purchase availability as the average availability when energy was most needed. Conservation Coalition contends that this is not consistent with Commission direction from the 2021 ERP/CEP that the Company should model all WECC regions and not limit market purchases based on historical purchases. Conservation Coalition points out that the Company's practice here could create additional risk if its neighbors have less power available than it has assumed, and that this practice could fail to identify good opportunities for interregional transmission. Conservation Coalition recommends that the Commission require the Company to update its RA Study for the supplemental RFP to reflect any data the Company possesses regarding effects of Markets+ participation on curtailments and market purchases and sales.[272]

b. Findings and Conclusions

318. We direct Public Service to include relevant new information based on its experience with Markets+ as it goes into the base and supplemental RFPs. In addition, the representation of market purchases must be updated in the 2027 RA study Application filing discussed above to reflect the Company's participation in the SPP Markets+ market.

[270] Hr. Ex. 1602, Att. JG-3, pp. 19-21.
[271] UCA's SOP at pp. 14-15.
[272] Hr. Ex. 801, Stenclik Answer, pp. 38-40; Conservation Coalition's SOP at pp. 27-28.

5. Treatment of Distributed Solar and Demand Response in the RA Study

a. Party Positions

319. The Company treats both distributed solar and demand response ("DR") as resources rather than load modifiers, adding their impacts back into its net (or "obligation") load to get to gross (or "native") load.[273] ELCCs were then applied to these resources to model their impacts to load in capacity expansion.

320. WRA and SWEEP argue that distributed solar is market driven and procured by customers rather than the utility so it is illogical to use an ELCC methodology for it. WRA and SWEEP also make methodological criticisms of the Company's approach to determining the ELCC for distributed solar. With regard to DR, WRA and SWEEP criticize the Company for limiting its DR forecast only to the types of DR programs it currently offers, which are subject to tariff limits on schedule, frequency and duration of dispatch, limiting their ability to respond to reliability events from 2-7 p.m. WRA and SWEEP also discuss additional, untapped DR resources such as controllable water heaters and cold thermal storage for which it claims there is large economic potential. WRA and SWEEP recommend DR be modeled as a load modifier rather than with an ELCC and that the Company should evaluate additional DR resource types for its next ERP along with interactive effects of combining DR with energy efficiency and distributed solar under a VPP framework.[274]

321. The Company opposes the WRA and SWEEP recommendation that DR be treated as a load modifier rather than evaluated in the ELCC framework. The Company argues that doing so would result in inaccurate representation of DR's reliability impact and would require that the

[273] Hr. Ex. 106, Goodenough Direct, p. 10; Hr. Ex. 109, Ming Direct, p. 32; Hr. Tr. June 18, 2025, p. 50:17-24.

[274] Hr. Ex. 1301, Eiden Answer, pp. 73-78, 80-88.

entire RA Study be redone, as this would represent a fundamental alteration of the Study. The Company contends that the time and expense of re-doing the study would not be prudent.[275]

b. Findings and Conclusions

322. We find compelling the WRA and SWEEP contention that as distributed solar and DR are resources implemented by customers rather than the Company, they should be treated as load modifiers rather than resources to which ELCCs are applied. Accordingly, we direct the Company to apply the hourly impacts of both these resources as load modifiers in all modeling conducted for Phase II of this proceeding, rather than applying ELCCs as the Company proposes. While this modification will impact the Company's resource need, we do not require Public Service to revise its RA Study to incorporate this issue.

6. Impact of daytime EV charging on ELCC for Solar

323. CRES/PSR argues that the RA Study will need to be redone once a revised forecast is produced that incorporates significant daytime charging of EVs. CRES/PSR attributes solar's low ELCC of 6-16 percent in summer and 0-3 percent in winter to the Company's assumption that load growth would primarily occur at night. CRES/PSR contends that starting in 2026, nearly all EV load should be considered to be managed, and that EV load between 5 p.m.-9 p.m. should be reduced by at least 40 percent due to the approximately $450 annual incentive created by the TOU rates that will take effect this October (in addition to the impact of the Company's managed charging programs). CRES/PSR contends that this change in assumptions will modify the load shape and significantly change both the Company's PRM and resource ELCCs.[276]

[275] Public Service's SOP at p. 21.
[276] CRES/PSR's SOP at pp. 5-10.

324. While we agree with CRES/PSR that the TOU rates will shift some EV charging to daytime off-peak periods, thereby modifying the overall load shape and potentially improving the actual load carrying capacity of solar resources, we find that much remains to be learned about the dynamics of consumer charging behavior and its response to utility programs, aggregator programs and revised TOU rates. While TOU rates may be successful in convincing many consumers to shift EV charging to lower-cost daytime hours when ample solar resources are available, we note that, at least in the short-term, limitations on the availability of workplace chargers may limit the degree to which this shift can occur. Accordingly, we do not find that there is sufficient evidence in the record to justify requiring the Company to modify its RA Study at this time as CRES/PSR request.

7. RA Study Representation of Correlated Outage Potential for Thermal Generators

325. CRES/PSR also criticizes the RA Study's treatment of "tail risks" for gas generation, stating that the Study fails to adequately reflect the temperature dependence of thermal generators. CRES/PSR notes that the RA Study relies on only five years of data and uses only average daily temperatures rather than hourly temperatures. CRES/PSR claims that other studies using more extensive data sets consistently found temperature dependence of thermal capacity availability, particularly at low temperatures. CRES/PSR contrasts this with the RA Study, which it claims has in some cases only one sample per temperature bin at temperatures below 20 degrees F. CRES/PSR argues no statistical inference can be drawn from such sampling.

326. Accordingly, CRES/PSR requests the Commission review this portion of the RA Study with the Company and Staff to determine its potential impacts on the conclusions the Study draws on the ELCC of firm gas resources. CRES/PSR suggests this could lead to a review of

weatherization practices and fuel supply chain vulnerabilities, potentially avoiding gas-related interruptions that have plagued other regions. CRES/PSR supports either a more conservative assumption for the ELCC of gas resources at extreme temperatures or a showing by the Company that its gas resources are not subject to this vulnerability.[277]

327. We find that the data in the RA Study that CRES/PSR cites as problematic indicates no temperature dependence of unit availability. Since there is no information on the record that the Company's thermal units are subject to correlated outage at extreme temperatures, we see no basis for CRES/PSR's request that an adjustment be made to the ELCCs of thermal units. However, we direct the Company to ensure that in the future it presents a more rigorous evaluation of any potential temperature dependence of thermal unit availability, perhaps using hourly rather than average daily temperatures.

K. May Valley – Longhorn Extension

328. The May Valley Longhorn Extension ("MVLE") is a proposed 90-mile, 345 KV line that would extend the Colorado Power Pathway south from the May Valley substation, providing access to the wind resource in southeast Colorado. In Proceeding No. 21A-0096E, the Commission granted Public Service a conditional CPCN for the MVLE, which could become unconditional upon approval of a resource portfolio including its costs in the 2021 ERP/CEP. While such a portfolio was not selected there, the Commission did grant an extension to the conditional CPCN to this proceeding, where again, the CPCN for the MVLE will become unconditional if the Commission approves a portfolio including its costs in Phase II. In Proceeding No. 21A-0096E, the Company estimated MVLE costs at just under $250M.

[277] CRES/PSR's SOP at pp. 24-27.

1. Party Positions

329. In its Rebuttal and SOP, the Company requests that the MVLE CPCN be granted prior to the conclusion of Phase II of this proceeding, stating that costs are likely to continue to escalate as time goes on, and that the line would provide bidders certainty of access to some of the lowest cost wind resources in the state. The Company also notes support for the MVLE from both CEI and WRA and SWEEP. The Company states that unconditional approval is more critical now to capture time limited tax-advantaged generation. In Rebuttal, the Company provides an updated cost estimate of $304 million, with an in-service date of Q3 2029. If a CPCN is granted, the Company proposes to work with Staff to develop a performance incentive mechanism ("PIM") parallel to that used for other Colorado Power Pathway segments and to submit it in Proceeding No. 21A-0096E.[278]

330. The Company also notes that per the JTS Transmission Study, large amounts of new renewable generation in southeastern Colorado, *i.e.*, in the area of the MVLE, could trigger the need for additional 345 kV transmission capacity running from May Valley to Sandstone and/or an additional 345 kV line to network the existing Pronghorn tie line. Public Service indicates this additional capacity would add between $224 and $786 million to the costs estimated in the JTS Transmission Study. The Company anticipates that it should be able to provide preliminary indication in its Phase II Report if there is a need for this additional capacity.[279]

331. CEI states simply that the Commission should approve the MVLE in the Phase I decision, and that it would support the PIM that was applied to the Colorado Power Pathway.[280]

[278] Public Service's SOP at pp. 26-27.
[279] Hr. Ex. 105, Siebenaler Direct, pp. 61-62.
[280] CEI's SOP at p. 27.

332. CIEA advocates that the Commission approve the MVLE CPCN, stating that the line is comparatively low-cost tapping perhaps the best wind resource in the state. It notes that the MVLE would increase geographic diversity and allow for additional low-cost interconnections.[281]

333. WRA and SWEEP state that the MVLE should be made available as an option for bidders to consider during Phase II of this Proceeding and that if the MVLE project is included in the approved portfolio, the Commission should grant the Company a full CPCN for the project.[282]

334. UCA opposes an unconditional CPCN for the MVLE, unless the selected portfolio can justify its $304 million estimated costs along with those of the $1.8 billion Harvest Mile-Chambers-Sandown-Cherokee ("HCSC") line, which UCA claims generation connected to the MVLE would necessitate. UCA argues these costs are unnecessary if there is capacity that does not require these transmission additions and points out that their costs are not included in the net present values shown in the Company's application.[283]

335. Climax takes no position regarding the approval of the MVLE, but advocates that any PIM for the MVLE not be adjudicated in this Proceeding. Instead, Climax argues any PIM should be considered in associated CPCN proceedings and guided by the same parameters applied to Power Pathway projects. Climax also asserts that if the MVLE is approved, its baseline cost should be fixed at $304 million.[284]

336. CEO recommends that the Commission adopt the same approach to the MVLE that it did in the 2021 ERP/CEP. CEO recommends that bidders be allowed to specify interconnection to the MVLE, that bidders proposing interconnection to the MVLE be required to specify an

[281] CIEA's SOP at p. 30.
[282] WRA and SWEEP's SOP at p. 30.
[283] UCA's SOP at pp. 26-28.
[284] Climax's SOP at p. 6.

alternate interconnection point and to include project costs assuming MVLE interconnection and the alternate interconnection point.[285]

337. Staff argues that the Commission should reject the Company's Rebuttal proposal. It notes the Commission's prior decision to approve an unconditional CPCN in this proceeding only if the approved portfolio includes the MVLE. Staff reacts to the Company's claim that MVLE approval now will reduce costs by stating that there still remains uncertainty about whether the line will actually be needed, and that this uncertainty will be reduced in Phase II. Staff states that this approach is particularly appropriate due to the uncertainty introduced by recent changes to renewable tax credit eligibility, since the need for the MVLE will be based on wind bids.[286]

2. Findings and Conclusions

338. Although there is considerable uncertainty regarding how the phase out of the renewable tax credits under the federal Reconciliation Bill will be implemented, it is unlikely that an accelerated approval of the MVLE in Phase I will impact whether the associated renewable projects connecting to that line will be eligible for the tax credits. If current regulations regarding the definition of the term "begin construction" are largely maintained, developers will not need the approval of the MVLE to begin construction. If this definition is substantially modified consistent with the recent executive order, it is doubtful new renewable projects arising from the JTS could be eligible for the tax credits. Ultimately, there is too much uncertainty for this factor to control whether an unconditional CPCN for the MVLE should be granted in Phase I.

339. Moreover, if the addition of new renewable generation capacity in southeast Colorado necessitates additional costly transmission capacity for system reliability or power

[285] CEO's SOP at pp. 30-31.
[286] Staff's SOP at pp. 18-19.

deliverability, the Company's estimate of the cost of such transmission must be a factor that we consider in our Phase II Decision, including as to the cost effectiveness of the MVLE. Accordingly, we direct the Company to incorporate a line item presenting its estimate of the PVRR for all such additional transmission required for any Phase II portfolio that would trigger the need for it. This line item shall be separate from and in addition to the estimated cost of the MVLE, if that line is triggered by one or more of the Phase II portfolios. Waiting until we have a better understanding of the full costs of the transmission necessary for new renewable generation in southeast Colorado further supports our decision to defer granting the CPCN for the MVLE until after Phase I.

340. The Commission recognizes the evidence in the record that Public Service lacks sufficient transmission capacity to acquire the magnitude of renewable generation the JTS envisions, even though our decision to reduce the Company's load forecast may make the need for additional transmission capacity somewhat less acute. Ultimately, however, we agree with Staff, CEO, and UCA that the Commission should maintain our initial approach and defer granting the MVLE CPCN until Phase II of this Proceeding. The decision on whether to move forward with this considerable investment will wait until there is a showing that a portfolio including the cost of the MVLE and any related transmission investment in southeast Colorado is in the public interest.

L. Transmission Cost Adders and Credits

1. Party Positions

341. In Direct, the Company asks the Commission to approve a set of modeling adders and credits designed to reflect the locational- and interconnection voltage-dependent costs that new generating resources impose on the system. These adders and credits are intended to incentivize the Company's capacity expansion planning model to select bid resources that

minimize the combined cost of generation and transmission. Based on transmission cost estimates developed through its JTS Transmission Study, the Company proposes a modeling adder of $238/kW for all bids other than those connecting to the distribution system, those interconnecting to the Colorado Power Pathway or those that propose to reuse the interconnection facilities of retiring generators. Bidders proposing interconnection within and west of the Denver Metro Constraint would be credited $191/kW. Also, any distribution-connected bids connecting to eligible feeders,[287] including aggregated distributed energy resources ("ADERs"), would be given a modeling credit of $69/kW-year.

342. UCA opposes the application of blanket adders and credits, arguing that bids should be burdened or credited based on the actual costs that their interconnection would impose on the system. UCA contends that the Company's proposal removes the incentive for bidders to find low-cost locations and propose projects that save customers money. Noting that the value of the adder is driven primarily by the $1.8 billion HCSC project, UCA argues that these costs should not be socialized but should be added only to those projects that would make the HCSC necessary. UCA therefore recommends the Commission require the Company to carefully define where projects would trigger the need for the HCSC project. Similarly, UCA states that it also opposes the use of a blanket distribution credit, arguing that such a credit should be based on actual costs that a project would avoid, which are location specific.[288]

343. While CCSA supports the basic structure of the Company's adder and credit proposal, it states that the specific values it recommends more accurately reflect the costs that bids impose or value they provide based on their location. CCSA begins its argument by noting that the

[287] Per the Company's VPP application, feeders are eligible if they are over the 75% planning load limit, do not have mitigations in service by the end of 2025 and have a load shape similar to the bulk system load shape.
[288] UCA's SOP at pp. 28-30.

Company's projected transmission and distribution capital expenditures over the next 20 years accounts for between 67 percent and 73 percent of total capital expenditure, depending on load forecast. It contends that the Company's initial estimates of transmission spending have been conservative in the past, citing the "$2 billion surprise" in the 2021 ERP/CEP. CCSA argues that unless the Company accurately accounts for the cost of delivering JTS generation, these costs will drive significant upward pressure on rates. It notes that its members plan to bid distribution-connected solar and storage resources that can defer or avoid these delivery-related transmission and distribution costs, but CCSA contends that it is essential to account for the very substantial delivery costs of utility-scale resources in the bid evaluation process. CCSA argues that approving its adder and credit values will help to ensure that dispatchable, distribution-connected resources, which it claims do not require new transmission investments, can compete fairly.[289]

344. CCSA advances a $290/kW transmission adder, which is based on two adjustments to the Company's calculation of $238/kW: 1) CCSA uses the cost and load calculations across both the base and low forecast, whereas the Company only considers the base forecast; and 2) CCSA includes the cost of the MVLE in its analysis for the five scenarios in which the MVLE is expected to be needed, whereas the Company excludes that cost completely. With regard to the first adjustment, CCSA argues it is more reasonable to use all scenarios to capture a broader range of possible future transmission buildouts. Regarding the MVLE, CCSA contends this treatment is consistent with how all other potential transmission projects are treated, noting that the Company provides no explanation why the MVLE should be treated differently. CCSA notes the Company makes no attempt to rebut these methodology adjustments.[290]

[289] CCSA's SOP at pp. 4-6.
[290] CCSA's SOP at pp. 7-8.

345. CCSA notes Staff's argument that the $1.8 billion HCSC project should be removed from the adder calculation because it appears in all scenarios and therefore the same cost would be applied to all bids regardless of location, resource type, or interconnection point. However, CCSA asserts this reasoning is flawed because the transmission adder will not apply to distribution-connected bids. CCSA argues this is exactly the purpose of the adder—to level the competitive playing field between utility-scale bids and distribution-connected bids by reflecting the significant costs of transmission. CCSA also opposes UCA recommendation to reject the proposed adder by arguing that the record of this case does not include sufficient information to enable more locationally precise adders. CCSA contends the perfect should not be the enemy of the good.[291]

346. CCSA also advances a "Base Transmission Credit" of $263/kW for resources connected anywhere on the distribution system, which would be stackable with an adjusted version of the Company's proposed credit for resources interconnected within the Denver Metro Constraint. CCSA proposes that the Base Transmission Credit be calculated by dividing the difference in long-run transmission costs between the base forecast and the lower low forecast—importantly, excluding the cost of the two projects on which the Denver Metro Transmission Credit is based—by the long-run change in loads between the two forecasts. CCSA also contends the Company's calculation of the Denver Metro Transmission credit is well founded conceptually but flawed in that the denominator of the calculation assumed that all DER are located within the Constraint. CCSA argues that since approximately 15 percent of DER installed would be outside of the metro area, the denominator should be only 85 percent of the difference in DER installed between the two scenarios used to calculate the credit, raising the credit

[291] CCSA's SOP at pp. 8-9.

from the Company's proposed $191/kW to $210/kW. Because the costs of transmission upgrades associated with the Denver Metro Credit were excluded from CCSA's calculation of its proposed Base Transmission Credit, CCSA asserts these two credits should be stackable for resources interconnecting within the Constraint.[292]

347. Interwest points out that in response to questioning by Chair Blank at hearing, the Company acknowledged that transmission costs identified in portfolios remained similar, yet the transmission adder of $238/kW is based on the idea that transmission costs are linearly related to generation added. Interwest contends that record does not indicate that transmission costs are related to the size of a generator, and so argues the transmission adder should be eliminated or addressed more granularly. Interwest argues further that under the Phase II Framework, transmission costs will be more clearly identified for bidders when they submit bids, so this "arbitrary" adder is unneeded. Interwest asserts significant reduction in the adder is warranted.[293]

348. Staff argues the transmission adder the Company proposes is excessive and will result in a bias toward smaller, gas-intensive portfolios. Staff contends that since it showed up in every scenario the Company modeled in its JTS Transmission Study, the $1.8-$1.9 billion HCSC project is not avoidable, and so should not be included in the costs used to calculate the adder. Staff demonstrates the impact by applying the Company's proposed $238/kW adder to the high-gas, moderate-renewables Baseline portfolio and the high-renewables Bookend I portfolio simulated in the Transmission Study. The modeling penalty from the adder amounts to $1.84 billion for the Baseline portfolio and $3.39 billion for the Bookend I portfolio, which Staff argues, demonstrates the adder will insert a bias toward gas-heavy portfolios. Staff therefore

[292] CCSA's SOP at pp. 9-13.
[293] Interwest's SOP at p. 11.

recommends the cost of the HCSC be removed from the adder calculation, resulting in an adder of $23/kW. Staff recommends that if the Commission does not approve this lower adder, the Commission should direct the small stakeholder group convened to address transmission issues under the Phase II Framework to evaluate and propose a more appropriate adder for use in Phase II.[294]

349. With regard to the proposed credit for resources located within the Denver Metro Constraint, Staff argues that both the calculation and application of the credit are not well supported. Staff points out that the Company calculated the credit as the ratio of the cost difference between the Bookend 2 and Baseline portfolios from the JTS Study—less the cost of the MVLE—to the difference in installed ADER between the two portfolios. Staff argues this method assumes that ADER is the only factor affecting transmission costs between the two portfolios, ignoring that the Bookend 2 portfolio has much less wind and solar, none of which is connected to the MVLE (unlike the Baseline portfolio). Staff also echoes CCSA that not all of the modeled ADER are located within the Denver constraint. Staff thus concludes it is inappropriate to assume that the reduced transmission costs in the Bookend 2 portfolio are due solely to ADER.[295]

350. Staff also takes issue with the credit boundary map the Company provided in its Rebuttal, noting that it differs greatly from the map presented in the CPCN Proceeding on the Denver Metro upgrades (Proceeding No. 24A-0560E), which purports to show the general areas that provide value to mitigating the Denver Metro Constraint. Staff contends the map captures areas in the west that require more study and excludes areas northeast of Denver that were identified as beneficial to the constraint. This, Staff argues, makes it difficult to determine if the

[294] Staff's SOP at pp. 12-14.
[295] Staff's SOP at pp. 14-15.

credit is being applied properly. Staff recommends the Commission require the Company to perform additional comparative transmission modeling to fix the deficiencies in the calculation and application of the credit. Staff further recommends the small stakeholder group proposed under the Phase II Framework have the opportunity to review the Company's additional modeling.[296]

351. Like Interwest and Staff, CRES/PSR notes the lack of correlation between transmission investment cost and portfolio size in the Company's modeling and argues there is no reason to believe that the additional cost or use of transmission is somehow proportional to portfolio size. CRES/PSR is therefore critical that the use of a $/kW adder will penalize renewable resources with low capacity factors, and supports Staff's proposal (removing the cost of the HCSC from the calculation) as being the most reasonable approach for this Proceeding.[297]

352. Pivot Energy supports CCSA's arguments regarding the utilization of all eight transmission portfolios for determining the transmission adder and for including the cost of the MVLE in the calculation. With regard to the latter, Pivot Energy notes the updated cost estimate from Rebuttal for the MVLE is $304 million but CCSA used the $272 million cost included in Direct. Using the updated cost would raise the adder from the $290/kW CCSA proposes to $293/kW. Pivot Energy also supports CCSA's argument that the Company calculation of the Denver Metro credit should have assumed only 85 percent of the DER capacity as the denominator or the calculation and therefore supports CCSA's contention that the credit should be $210/kW.[298]

353. Noting that the only way to defer or avoid the Company's enormous projected costs for transmission investments over the next 20 years is to take them into account in the ERP process, Pivot Energy states it supports the logic and analysis in CCSA's answer testimony and SOP that

[296] Staff's SOP at pp. 15-16.
[297] CRES/PSR's SOP at pp. 12-13.
[298] Pivot Energy's SOP at pp. 6-10.

there should be a Base Transmission Credit of $263/kW for any distribution connected resources anywhere on the Company's system and that this should be stackable with the Denver Metro credit (as adjusted by CCSA).[299]

354. CIEA argues the Commission should treat the Company's estimated JTS transmission costs as fixed, since they will be needed under any scenario to connect the JTS resources to be procured under both the base and supplemental RFPs. CIEA contends the adder would be applied equally to a project next to a Public Service substation and one located in Wyoming, terming it "a blunt tool that is really just a proxy for the lack of current transmission investments that should be assumed to arise out of whatever Phase II portfolio is adopted."[300] As a result, CIEA contends the transmission adder is unnecessary. CIEA argues further that the Denver Metro credit is unlikely to be effective, since the defined area is "small, mostly mountains or built area" and that it does not have the ability to host 4,500 MW of wind.[301] CIEA claims that even with unreasonable generation assumptions, the JTS Transmission Study shows that it is not possible to avoid Denver Metro upgrade costs.[302]

355. CEI states that the Company's reluctance to adopt avoided distribution and transmission values in this Proceeding is not unexpected given its bias to favor capital expenditures. CEI supports the alternative values calculated by CCSA for transmission and distribution credits and recommends that if the Commission does not accept those values, it should ensure the avoided cost valuations developed in the DSP/AVPP proceeding include both a base

[299] Pivot Energy's SOP at pp. 10-13.
[300] CIEA's SOP at p. 29.
[301] CIEA's SOP at p. 28.
[302] CIEA's SOP at p. 28.

credit value and a locational value based on the expected avoided costs of constrained circuits or feeders.[303]

356. CEO supports Staff's positions on the transmission adder. [304]

357. Public Service counters arguments raised in Answer by stating that the Company's methodology for determining the adders and credits is reasonable because the assumptions it used are representative of future load and generation additions. The Company acknowledges that its methodology is only an approximation but that it is reasonable and should be approved.[305]

358. While Public Service acknowledges there are many ways to approximate a transmission adder or credit, the Company asserts that there is no "correct" value, because the variability of possibilities representing the ratio of incremental transmission costs to incremental kilowatt of generation is large. The Company supports this contention by noting the large range between Staff's proposed $23/kW adder and CCSA's proposed $290/kW adder. The Company therefore states that it stands by the adder and credit values in its Direct. The Company asserts this is reasonable because the Base cases are more likely representative of future load and generation additions and because the values quantify a relationship that can only be approximated and that they "intuitively seem about right."[306]

359. The Company disagrees with Staff's recommendation to exclude the Harvest Mile 345 kV to Cherokee 230 kV line from the transmission adder contending that line is an actual expected transmission cost of adding new generation and excluding it would artificially lower the "marginal cost." The Company suggests that without the Harvest Mile to Cherokee project

[303] CEI's SOP at pp. 17-20.
[304] CEO's SOP at pp. 15-16.
[305] Public Service's SOP at pp. 25-26.
[306] Hr. Ex. 118, Landrum Rebuttal, pp. 44-45.

included in the adder, the model's decision-making would be blind to the significant incremental transmission investment required to add incremental generation.[307]

360. Regarding CCSA's recommendation to incorporate all eight Base and Low JTS Transmission Study cases in the transmission adder calculation, the Company again states that it believes the Base Case scenario is the more likely expectation of future load and resource additions. Public Service also argues that one could combine all the different transmission findings in various ways to come up with multitudinous variations of cost ratios, none of which is likely that much more precise than another. The Company supports the adder and credit values from its Direct Case as a reasonable approximation.[308]

2. Findings and Conclusions

361. The Commission recognizes the importance of transparency with the linkage between different portfolios of generation resources and the comparative transmission costs imposed on the system, especially given the shortcomings in the 2021 ERP/CEP in this regard. With regard to UCA's advocacy for a system of adders and credits based on costs caused or avoided by individual bids, we find that this recommendation is impracticable if not impossible, as determining the costs imposed or avoided by individual bid resources would require a degree of modeling analysis that simply cannot be done in the constrained time between the selection of bids and the Company's Phase II Report. Moreover, a single bid might not impose or avoid specific incremental costs, whereas a portfolio of selected bids would, making it much more difficult to assign specific costs and benefits to individual resources.

[307] Hr. Ex. 118, Landrum Rebuttal, pp. 44-45.
[308] Hr. Ex. 118, Landrum Rebuttal, pp. 44-45.

362. CCSA's point that the Company considered only the transmission costs it identified for the base forecast in calculating the adder and leaves out all results for the Low Forecast is well taken. Given the approved load forecast appears to be more in line with the Company's low forecast,[309] we agree with CCSA that the adder methodology should include the cost and transmission capacity results of the Company's modeling for the low forecast. We therefore direct the Company to recalculate the adder using all results modeled as suggested by CCSA, subject to additional changes discussed below.

363. CCSA and Pivot Energy ask that the cost of the MVLE be included in the calculation of the transmission adder because the MVLE is likely to be needed for any portfolio and not including it is inconsistent. In hearing, however, the Company pointed out that the costs of the MVLE will be included for any portfolio that includes one or more bid resources connecting to the MVLE, so that including its costs in the adder would be double counting.[310] We agree with the Company's logic that the cost of the MVLE should be excluded from this calculation.

364. Regarding Staff's contention that the $1.8-$1.9 billion HCSC project is unavoidable and so should be excluded from the adder calculation, we note that this cost was the primary contributor to the "$2 billion surprise" in the 2021 ERP/CEP. This specific project was removed from the ongoing CPCN application for Denver Metro transmission upgrades (Proceeding No. 24A-0560) largely because the Company determined that it was not needed to support the approved portfolio from the 2021 ERP/CEP. However, the Company's JTS Transmission Study identifies the need for the HCSC project in almost every portfolio it evaluated. Accordingly, we agree with Staff that the record suggests this project is unavoidable, and therefore

[309] As discussed above, the load forecast used for the base RFP will depend in part on how many large loads execute binding agreements prior to the RFP's release.

[310] Hr. Tr. June 13, 2025, p. 192:9-18.

that it should be excluded from the adder calculation. This will have the effect of dramatically reducing the adder, and largely addressing the bias toward smaller, gas-intensive portfolios that Staff discusses.

365. We do not agree, however, with the parties advocating that the adder should be entirely eliminated. It appears the transmission costs that are truly incremental and avoidable should be attributed to projects that necessitate them, where such costs can be practically identified and included in the capacity optimization process, as the Company has attempted to do here. Furthermore, CCSA makes the valid point that distribution-connected resources are unlikely to contribute to the need for transmission upgrades, and the transmission adder properly reflects this benefit in expansion planning.

366. Parties raise essentially three types of criticisms regarding the Company's calculation of its proposed Denver Metro transmission credit: (1) the denominator of the calculation assumes that all DER are installed within the Denver Metro constraint; (2) the calculation fails to account for modeled portfolio differences other than the quantity of DER installed; and (3) the map the Company provides in Rebuttal indicating where the Denver Metro transmission credit would be applicable is inconsistent with that provided in the Denver Metro CPCN and requires additional study. We agree with these parties that there are significant shortcomings to the Company's credit calculation methodology. CCSA recommends that the denominator in the calculation (change in DER MW between the Baseline and Bookend 2 portfolios) be reduced by 15 percent because it claims that is the amount of DER that will be installed outside of the Denver Metro Constraint. However, CCSA includes nothing in the record to substantiate this specific value. However, Staff is correct that the change in installed DER assumption is far from the only factor affecting the costs of the portfolios referenced in the credit

calculation. We therefore endorse Staff's recommendation that the Commission require the Company to perform additional comparative transmission modeling to fix the deficiencies in the calculation and application of the credit, and that the small stakeholder group have the opportunity to review and comment on the results of this modeling.

367. While we recognize the risks of adding more process between this Decision and the RFP, CEI raises a legitimate request that if the transmission credit is modified after the Phase I Decision, parties should be notified of the change in the transmission credit and should have an opportunity to respond—prior to the Phase II modeling. We therefore grant CEI's request and require that the Company file a notice of any changes to the adder or credits following this Phase I Decision, describing the changes made along with the methodological justifications for the changes. Parties will then have the opportunity to respond.

368. Finally with regard to transmission adders and credits, we note that neither the Company nor any other party responded to the CCSA proposal that there should be a credit for all distribution-connected resources system wide that would be in addition to the credit for resources connecting at the distribution level within the Denver Metro constraint. As there is little on the record to support the CCSA position, we will deny its request and approve the Company's proposal to provide a $69/kW credit to resources interconnecting on constrained distribution circuits.[311]

M. Phase II Portfolios

1. Party Positions

369. Public Service proposes to model two groups of Phase II portfolios or "solution sets." The first solution set meets the 80 percent emission reduction by 2030 target and then

[311] Commissioner Gilman dissents on this point and would have directed the small stakeholder group to work with the ITA and the Company to study the issue and revise the credit.

declines to 100 percent emission reduction by 2050. The second solution set contains an 86 percent emissions reduction constraint in 2030 to match the modeled emissions reduction form the approved portfolio in the 2021 ERP/CEP as well as a 90 percent emissions reduction target in 2033. After 2033, this second solution set declines to 100 percent emission reduction by 2050.[312]

370. Each solution set will have the following six portfolios, for a total of 12 portfolios: 1) informational least cost plan with SCC, 2) SCC with Company-ownership requirements, 3) SCC with accelerated emissions reduction in which there is a linear reduction in emissions to 100 percent remission reduction by 2030, 4) a least cost informational plan with $0 SCC, 5) Company ownership requirements with $0 SCC, and 6) a $0 SCC accelerated emissions reduction with a linear reduction in emissions to 100 percent by 2030. [313]

371. In addition to the above 12 portfolios, Public Service proposes modeling two checkpoint portfolios in which there is no emissions reduction constraint. [314] The Company states that neither checkpoint portfolio is meant for ultimate selection but asserts these portfolios may be "useful, if not critical, in final portfolio decision making."[315] The Company states it is critical for intervenors and the Commission to understand the impact of the emissions targets on acquisition plans. Public Service adds that while the checkpoint cases will inform the baseline for the CEP Rider, the Company submits that the CEP Rider baseline development is more complex than simply using the checkpoint case. Instead of using the checkpoint portfolios for the CEP Rider baseline, the Company proposes to address the CEP Rider baseline in the 120-Day Report based on the presented portfolios in the JTS Base RFP Phase II process.[316]

[312] Public Service's SOP at p. 8.
[313] Hr. Ex. 117, Ihle Rebuttal, p. 57.
[314] Hr. Ex. 117, Ihle Rebuttal, p. 57.
[315] Hr. Ex. 118, Landrum Rebuttal, p. 15.
[316] Public Service's SOP at pp. 9-10.

372. The Company proposes a "midpoint ownership" portfolio, which would only be run if the level of Company ownership in the least-cost plan is less than 30 percent on a nameplate MW basis. Public Service maintains that the least-cost plan, which contains no utility-ownership constraint, already tests the cost-effectiveness of utility ownership and that the midpoint ownership portfolio would potentially provide an additional portfolio consistent with party proposals for a low ownership portfolio.[317]

373. To determine backup bids, the Company proposes to rerun the Preferred Portfolio through EnCompass for each technology type (wind, solar, hybrid, storage, firm dispatchable, etc.) by locking in all resources except the selected type, removing the selected bid for the specific type, and only allowing bids of that type to come in as replacements.[318]

[317] Public Service's SOP at p. 9.
[318] Hr. Ex. 102, Landrum Direct, Rev. 1, p. 66.

374. Staff proposes the following 14 Phase II portfolios, matching the number proposed by the Company:

1) Checkpoint portfolio with $0 SCC
2) A least cost portfolio with $0 SCC, an 80 percent by 2030 emissions constraint, and no required Company ownership
3) A least cost portfolio with $0 SCC, a 90 percent by 2033 emissions constraint, and no required Company ownership
4) A Company-ownership portfolio with $0 SCC, an 80 percent by 2030 emissions constraint, 50 percent Company-ownership requirement, and a linear emissions constraint
5) A Company-ownership portfolio with SCC, an 80 percent by 2030 emissions constraint, 50 percent Company-ownership requirement, and a linear emissions constraint
6) A Company-ownership portfolio with $0 SCC, a 90 percent by 2033 emissions constraint, and a 50 percent Company-ownership requirement
7) A Company-ownership portfolio with SCC, a 90 percent by 2033 emissions constraint, and a 50 percent Company-ownership requirement
8) An accelerated emissions portfolio with SCC, emissions constraints of 86 percent by 2030 and 90 percent by 2033, a 50 percent Company-ownership requirement, and a linear emissions constraint
9) An accelerated emissions portfolio with SCC, emissions constraints of 86 percent by 2030 and 90 percent by 2033, and a 50 percent Company-ownership requirement
10) A lower Company-ownership portfolio that matches the metrics of the preferred portfolio that the Company advances in Phase II but with a maximum 40 percent Company ownership
11) A low new gas portfolio that matches the metrics of the preferred portfolio but constrains new gas capacity to no more than 50 percent of the capacity included in the Company's preferred portfolio
12) A no tariff costs that matches the metrics of the preferred portfolio but excludes any tariff costs identified by bidders
13) An alternative tariff portfolio that matches the metrics of the preferred portfolio but uses either half of the identified tariff costs or doubles the identified tariff costs, depending on the level of tariffs in place at the time of project bidder.
14) A just transition credits portfolio that matches the metrics of the preferred portfolio but eliminates the just transition modeling credits.[319]

[319] Hr. Ex. 2606, Att. SJD-10; Staff's SOP at pp. 11-12.

375. While most of Staff's proposed modeling scenarios are similar to those of the Company, Staff argues its proposal provides a broader range of distinctive "looks," including looks at increased emission reductions, lower Company ownership, lower new gas resources, and the impact of import tariffs, all without increasing the number of portfolios.[320] Staff notes the Company characterized Staff's proposed Phase II portfolios as a reasonable alternative at hearing.[321]

376. WRA and SWEEP state they are directionally supportive of Staff's proposed suite of Phase II portfolios but suggest certain modifications. First, WRA and SWEEP argue the Commission should strive to include a 90 percent by 2033 emission constraint in as many of the portfolios as possible and an 86 percent by 2033 emission constraint in at least several of the portfolios. In addition, they argue the Commission should require the Company to model all portfolios with and without the inclusion of just transition modeling credits. WRA and SWEEP assert these portfolios together with Staff's existing proposals would only result in 22 total portfolios—far fewer portfolios that what was presented in the 2021 ERP/CEP. In the alternative, the Commission should at minimum require that a sensitivity of the preferred portfolio be modeled with and without just transition credits. They note the downsides with this approach include the lack of comparability to other portfolios, and the inability for the Commission to take corrective action if the portfolio modeled without just transition credits indicates that the credits added substantial cost to every other portfolio in which the credits were included.[322]

377. WRA and SWEEP also support two post-Phase II portfolios. The first would exclude large loads to provide an initial approximation of the incremental resource selection and costs driven by the addition of large load customers. The second would be the checkpoint

[320] Staff's SOP at pp. 11-12.
[321] Hr. Tr. June 17, 2025, at p. 80.
[322] WRA and SWEEP's SOP at p. 23.

portfolios. If one or both of the checkpoint portfolios is modeled at all, WRA and SWEEP argue it should be after the Phase II decision to expedite Phase II and ensure consistency with the statute and USA.

378. Conservation Coalition recommends modeling Phase II portfolios with a goal of producing meaningful variations across three main factors: cost to customers; emissions reductions; and just transition benefits (with a minimum level of reliability across all portfolios). Conservation Coalition accordingly offers several recommendations. For instance, Conservation Coalition argues the Commission should decide in Phase I whether to include the SCC in the portfolios (*i.e.*, using $0 SCC or SCC in capacity expansion). Conservation Coalition asserts this would save time and resources compared to running each portfolio in Phase II both with SCC and with $0 SCC. Regarding the checkpoint portfolios, Conservation Coalitions argues they should only be run after the Phase II Decision, if at all, and should be modified to include the 100 percent emissions reduction by 2050. Conservation Coalition would also delete Staff's proposed linear emissions constraint. Conservation Coalition reasons that what happens after 2033 is of little importance to the base and supplemental RFP and there will already be portfolios with a 90 percent emissions constraint by 2033. Conservation Coalition recommends adding at least one portfolio in which Public Service is assumed to join a full ISO/RTO by 2030 and rejecting or reducing by half the just transition modeling credits.[323] Conservation Coalition goes on to suggest modified versions of the two suites of Phase II portfolios that Public Service and Staff advance.

379. Finally, Conservation Coalition argues the Commission cannot simply reuse the same portfolios for the base RFP and the supplemental RFP. Conservation Coalition asks the Commission to direct that the portfolios for the supplemental RFP not use the Company ownership

[323] Conservation Coalition's SOP at pp. 4-8.

targets. Instead, Conservation Coalition argues that each portfolio for the supplemental RFP should include the least-cost resources (subject to the constraints for that portfolio) without any explicit Company-ownership constraint in the model. Conservation Coalition similarly argues that if the Commission approves the use of the just transition modeling credits in the base RFP, it should consider whether it is still appropriate to use them for the supplemental RFP.[324]

380. CEC argues that § 40-2-125.5(3), C.R.S. requires the Commission to approve a resource plan that enables Public Service to achieve an 80 percent emissions reduction by 2030 and "seek to achieve" a 100 percent reduction by 2050 or sooner if it is "*technically and economically feasible*" and "in the public interest."[325] The statute also indicates that its purposes include "promot[ing] the development of *cost-effective* clean energy" that will "allow Coloradans to enjoy the benefits of *reliable* clean energy at an *affordable cost*."[326] Based on the likely cost increases for clean energy resources, CEC argues the Commission should evaluate any incremental impacts to reliability and affordability that result from exceeding the 80 percent threshold and select the most cost-effective Phase II portfolio that meets the 80 percent threshold while ensuring reliable service.

381. CC4CA opposes the Company's proposed checkpoint reference cases, arguing that Phase II modeling should be reserved for portfolios that the Commission can lawfully approve. Instead of the checkpoint portfolios, which have no emission reduction constraints, CC4CA argues the Commission should require two "Business as Usual" reference cases that would maintain the emissions constraints approved in the CEP.[327] CC4CA further argues that at least half of the Phase II portfolios should use the 86 percent by 2030 emissions constraint to be consistent with

[324] Conservation Coalition's SOP at pp. 9-11.
[325] CEC's SOP at p. 15 (quoting § 40-2-125.5(3)(a) (emphasis in original)).
[326] CEC's SOP at p. 15.
[327] CC4CA's SOP at p. 3.

the approved portfolio from the 2021 ERP/CEP. CC4CA also recommends two additional portfolios. First, CC4CA requests a no new gas portfolio, which only allows the model existing gas units with retirement dates during the RAP that can be extended as well as current PPAs that expire during the RAP and can be extended or rebid. Second, CC4CA recommends the Commission direct the Company to model a "health impacts analysis" portfolio, which would be a sensitivity of the Company's preferred portfolio that accounts for the costs of the health impacts of newly-constructed gas units, using either approach put forth by Healthy Air and Water Colorado.[328] Similar to other intervenors, CC4CA requests the Commission require Phase II portfolios be modeled with and without the just transition modeling credits.[329]

382. Interwest recommends an additional low Company-ownership portfolio in which Company ownership is limited to 45 percent. This 45 percent constraint would be applied to resources in excess of the $690 million investment or 500 MW accredited capacity minimum specified in the 2021 ERP/CEP's USA. Interwest argues this portfolio would help show the impact of higher Company ownership on cost, emissions reductions, reliability, BVEM score, and ability to address future concerns, allowing the Commission to weigh the various considerations appropriately.[330]

383. CIEA argues the Company should be required to provide Solution Sets that provide different views of Company ownership versus PPA projects. While CIEA does not advocate deviating from the utility ownership levels agreed upon in the 2021 ERP/CEP, CIEA notes that the CEP showed that Company-owned projects faced same uncertainties with supply chain and pricing that IPPs faced. In addition, CIEA requests that the Company provide a Solution Set where

[328] CC4CA's SOP at p. 4.
[329] CC4CA's SOP at p. 5.
[330] Hr. Ex. 501, Wilson Answer, pp. 23-24.

bidders that had appeared in multiple other Solution Sets could be removed from consideration and allow other bids to be populated. [331]

384. CEO argues the Commission should only run the checkpoint portfolios after Phase II. CEO also recommends the Company run at least one portfolio that includes an 86 percent reduction by 2030, a 90 percent reduction by 2033, and a 100 percent reduction by 2050, with SCC included.[332]

2. Findings and Conclusions

385. With certain modifications, we adopt Staff's proposed suite of Phase II portfolios, which we find to be superior to the Company's proposal. Staff pares down the Company's portfolios that simply test the impact of including SCC. For instance, Staff's least cost portfolios do not include the SCC. Conversely, Staff's accelerated emissions portfolios only include SCC and contain no $0 SCC. This is a reasonable approach for eliminating portfolios that provide little value and is directionally consistent with Conservation Coalition's recommendation to decide in Phase I whether to use SCC instead of modeling every portfolio twice. Staff replaces these mostly redundant portfolios with portfolios that examine lower Company ownership and lower new gas. These portfolios provide more varied options for Commission consideration without adding additional Phase II modeling burdens.

386. While Staff's suite of portfolios are preferable to the Company's proposal, we find certain additional modifications are necessary. To begin, we agree with concerns raised by WRA and SWEEP, Conservation Coalition, and CC4CA regarding the Company's checkpoint portfolios, one of which Staff includes in its proposed suite of portfolios. As CC4CA observes, it

[331] Hr. Ex. 700, Monsen Answer, pp. 85-86.
[332] CEO's SOP at pp. 20-21.

is unclear why Phase II resources should be expended modeling a portfolio that does not contain the statutory requirement to achieve an 80 percent emissions reduction by 2030. Instead of the checkpoint portfolio Staff proposes, we adopt a modified version of CC4CA's business as usual portfolio. Under this modified portfolio, the model would still be required to achieve the 80 percent by 2030 emissions reduction target but would have no subsequent emissions constraints. This portfolio meets the bare minimum required by statute and allows the Commission and parties to evaluate a scenario in which the model is not required to achieve 100 percent emissions reductions using existing technologies.

387. To be clear, this business as usual portfolio does not abandon the statutory goal of 100 percent emissions reduction by 2050. Rather, the portfolio leaves open the possibility that future emissions reductions from things like VPPs, increased market participation, additional interregional transmission, and new technologies like advanced geothermal and long duration storage could render unnecessary some of the wind, solar, and short-duration storage that would otherwise be acquired in the short-term. Given the documented price increases of wind, solar, and lithium-ion storage, recent changes to federal tax credits, and uncertainties about federal tariff policies, we want to ensure there are some portfolios in which the model is not forced to acquire large amounts of existing technologies when better alternatives may be available in the future.

388. In addition, we see little value in Staff's two portfolios that test the impacts of tariffs (*i.e.*, the no tariff costs portfolio and the alternative tariff case portfolio). While we do not discount the potential cost impacts of tariffs, given the dynamic nature of federal tariff policy, it is unlikely that these two portfolios would materially influence which portfolio is ultimately selected, let alone be selected themselves. Also, given how quickly the tariff situation may change, it is not clear that

tariffs modeled based on policies from the time the projects are bid will still be applicable when they are expected to be developed.

389. Instead of Staff's tariff portfolios, we direct Public Service to model two new portfolios. The first such portfolio is a no-new Company-owned gas portfolio. This portfolio would include the just transition modeling credits, the SCC, the 80 percent by 2030 and 100 percent by 2050 emissions constraints, and the 50 percent Company-ownership target. However, the portfolio would be restricted from including any new Company-owned gas units. As the Commission referenced in the 2021 ERP/CEP, reducing the amount of Company-owned gas resources increases the Company's ability to transition away from carbon emitting resources as we approach 2050 and reduces the risk that Colorado ratepayers will be burdened with the cost of stranded assets associated with gas units.[333]

390. The second new portfolio that replaces Staff's two tariff portfolios is an accelerated emissions portfolio that is modeled without just transition modeling credits. As set forth above, we find persuasive arguments from Staff, Conservation Coalition, CC4CA, and WRA and SWEEP, that there should be Phase II portfolios modeled both with and without the just transition modeling credits. This will help parties and the Commission understand the impacts the just transition modeling credits have on costs and resource selection and my help alleviate concerns that the just transition modeling credits may reduce competitive tension. This accelerated emissions portfolio will use the SCC, will have emissions constraints of 86 percent by 2030, 90 percent by 2033, and 100 percent by 2050, and will include at least 50 percent utility ownership. This portfolio will not include the just transition modeling credits.

[333] Decision No. C24-0052 at ¶ 100 issued in the 2021 ERP/CEP (Jan. 23, 2024).

391. We also replace Staff's proposed Portfolio 8, which is one of four portfolios testing Company-ownership, with a new portfolio that tests accelerated near term emissions reductions without the 100 percent by 2050 emissions constraint. We find that this additional accelerated emissions reduction portfolio will provide more useful information than another Company-ownership portfolio. Under this new accelerated emissions reduction portfolio, the just transition modeling credits will be included, the model will use SCC, there will be a 50 percent Company-ownership requirement, and the portfolio will have the following emissions constraints: 86 percent by 2030, 90 percent by 2033, but no 100 percent by 2050 constraint. As referenced above, given the cost pressures and changing federal policy, we find it appropriate to have another portfolio that leaves space for the use of future technologies, interregional transmission, and increased market participation to meet the 100 percent by 2050 goal.

392. For similar reasons, we find it appropriate to reduce the number of portfolios that require a linear emissions reduction. Requiring a constant pace of emissions reduction disregards potential future step-changes such as market participation. At the same time, however, we stop short of eliminating the linear reduction constraint entirely given that it promotes additional interim emissions reductions by requiring the model to acquire additional wind, solar, and storage resources. Accordingly, we retain the linear reduction constraint for Portfolio 9, which helps ensure the Commission has an aggressive emissions reduction option. Public Service shall remove the linear constraint from all other portfolios. For these portfolios without the linear constraint, the Company will keep all other emissions constraints (*e.g.*, the 2030 and 2050 requirements) but will remove intervening constraints, including the Carbon Caps set forth in Section 2.11 of the technical appendix.

393. In sum, Public Service shall model the following Phase II portfolios:

No.	Name	JT Credits[334]	SCC	Emissions pathway[335]	Comp. ownership	Additional emissions constraint
1	No new Company-owned gas	Yes	SCC	80/30	50%	None
2	Business as usual	Yes	SCC	80/30; no 100% by 2050 constraint	0%	None
3	Least cost portfolio	No	No	80/30	0%	None
4	Least cost portfolio	Yes	No	90/33	0%	None
5	Company ownership	Yes	No	80/30	50%	None
6	Company ownership	Yes	SCC	80/30	50%	None
7	Company ownership	Yes	No	90/33	50%	None
8	Accelerated emissions reduction	Yes	SCC	86/30 & 90/33; no 100% by 2050 constraint[336]	50%	None
9	Accelerated emissions reduction	Yes	SCC	86/30 & 90/33	50%	Linear
10	Accelerated emissions reduction	Yes	SCC	86/30 & 90/33	50%	None
11	Lower Comp. ownership	Yes	Match PP[337]	Match PP	40%	Match PP
12	Low New Gas	Yes	Match PP	Match PP	50%	Match PP
13	PP with no JT Modeling Credits	No	Match PP	Match PP	Match PP	Match PP
14	Accelerated emissions with no JT Modeling Credits	No	SCC	86/30 & 90/33	50%	None

394. We note that if the Company advances Portfolio 10 as the preferred portfolio, then Portfolio 13 becomes duplicative of Portfolio 14. Therefore, in the event Portfolio 10 is the preferred portfolio, then Portfolio 14 should be adjusted to mimic Portfolio 9's inclusion of the

[334] For purposes of this Table, just transition modeling credits is abbreviated as "JT Credits."

[335] For purposes of this Table, the 80 percent by 2030 emissions constraint is abbreviated as "80/30," the 86 percent by 2030 constraint is abbreviated "86/30," and the 90 percent by 2033 is abbreviated "90/33." Unless otherwise specified, all portfolios have the 100 percent by 2050 emissions reduction constraint.

[336] Although this portfolio does not have the 100 percent by 2050 constraint, in this portfolio gas-fired facilities would still be subject to early depreciation as well as the higher costs associated with hydrogen fuel.

[337] For purposes of this Table, preferred portfolio is abbreviated as "PP."

linear emission constraint. In other words, if Portfolio 10 is the preferred portfolio, then Portfolio 14 shall be modified to include the linear emission constraint.

395. Although we reject the Public Service's proposal to model the checkpoint portfolios, the Commission approves the Company's plan to address the CEP Rider baseline development based on the presented portfolios in the base RFP Phase II process.

396. Consistent with Conservation Coalition's recommendation and our discussion above,[338] we reject the 50 percent Company ownership target in the supplemental RFP. While the level of utility ownership will likely continue to be an important consideration given the differences between Company-owned projects and PPAs, we see no basis to maintain a 50 percent ownership target. Eliminating the 50 percent ownership target would make Portfolio 4 duplicative of Portfolio 7, so the Company would be able to eliminate either one. In order to test the impacts of varying amounts of utility ownership, Public Service shall run two variations on the supplemental RFP preferred portfolio. The first would set a utility ownership constraint of at least 50 percent, and the second would set a utility ownership limit of 40 percent.

N. Conforming Bid Policy and Modifications to PPA Provisions

397. Public Service recommends the Commission adopt a conforming bid policy under which developers can only submit bids that conform to the model PPAs approved in the Phase I decision. In other words, in response to the RFP, bidders would be required to provide a proposal and associated firm non-conditional bid price that is fully compliant with the Company's model agreements without markup or exceptions. Public Service argues this new approach will help the

[338] See ¶ 119 *supra*.

Company complete project evaluation and contract negotiations in a timely manner, as well as to ensure projects are compared on a like-for-like basis.[339]

398. The Company argues its conforming bid policy supports three objectives: first to ensure a fair, transparent and competitive RFP; second, to protect customers against bidders trying to shift risk and costs to customers through redlined bids and during post-selection negotiations; and finally, to improve the efficiency and effectiveness of the solicitation, selection and procurement process in Phase II. On this last point, the Company argues that a conforming bid policy will help prevent extended periods of bid evaluation and negotiation.[340] The Company notes that negotiation of specific language details will still occur at arms-length. The conforming-bid policy simply prohibits developers from submitting bids that rely on the assumption that fundamental aspects of the Model PPA will be modified.

399. To finalize a conforming model PPA, the Company in its SOP suggests a series of procedural steps that would allow for the submission and ultimate approval of a redlined PPA. For instance, within 14 days after the Commission issues a decision adjudicating the disputed issues with the model PPAs, the Company would file updates of each model PPA. Intervenors would then have 14 days to file comments, including redlined versions of the updated PPAs. Then the Company would have 14 days to file reply comments and updated PPAs. The Company contemplates that the Commission would issue a decision on the final model PPAs within 21 days of reply comments and possibly after a technical conference.[341]

400. CIEA, CEI, and Interwest all urge the Commission to deny the conforming bid policy. CIEA recommends bidders be allowed to provide commercially reasonable redlines to the

[339] Hr. Ex. 104, Bornhofen Answer, Vol. 2, p. 214.
[340] Hr. Ex. 120, Bornhofen Rebuttal, p. 9, 20.
[341] Public Service's SOP at p. 29.

model PPA with bids such that Public Service is aware of proposed edits. Public Service would have discretion to review bidder redlines, to reject bids under certain conditions, and to provide negative non-price factors for either excessive redlines or redlines that say "TBD."[342] CIEA argues there is a "striking absence in the record" showing the effectiveness of a conforming bid policy anywhere else.[343] Regarding the Company's assertion that the conforming bid policy allows for an apples-to-apples comparison, CIEA notes that approximately half of the approved generation projects may be owned by the Company, and such utility-owned projects are not required to comply with the model PPA terms but are allowed to submit bids with redlines to the term sheet.[344] CIEA further asserts that the risk of delay of the RFP and the resulting costs to ratepayers far outweighs the hypothetical value of extra litigation to arrive at a model PPA. CIEA argues the RFP cannot and should not be delayed to continue contract mediation. In the alternative, if the Commission decides to delay the RFP to decide PPA language, CIEA requests the Commission adopt the positions of CEI and Interwest.[345]

401. CEI recommends the Commission reject the proposed new model PPA and the conforming bid policy and by default adopt the model PPA approved in the last ERP—Proceeding No. 21A-0141E. If the Commission chooses to convene a process to develop an agreed-upon model PPA, CEI argues it should be aimed at the supplemental RFP only.[346] Throughout the Proceeding, CEI submitted considerable testimony regarding the unreasonableness of the Company's proposed PPA terms. CEI argues that when the proposed terms are reviewed and taken together, it presents a one-sided agreement that dramatically favors the Company.[347]

[342] CIEA's SOP at pp. 7-8.
[343] CIEA's SOP at pp. 14.
[344] CIEA's SOP at pp. 18-19.
[345] CIEA's SOP at pp. 22.
[346] CEI's SOP at pp. 6-7.
[347] *See* Hr. Ex. 2202, Pierce Answer, p. 61.

CEI asks the Commission not to leave this issue up to the Company to decide, arguing that even after the Company's concessions in Rebuttal, the parties remain far apart on key PPA terms. CEI warns that the Company's proposed terms are unreasonably burdensome to IPPs and that adopting a one-sided model contract shifts risk to IPPs, which is likely to increase the cost of bids and reduce participation.[348]

402. Interwest similarly recommends that the Commission reject the conforming bid policy in its entirety in favor of negotiability. Interwest asserts the conforming bid policy reduces flexibility in one of the most uncertain moments in electricity generation acquisition and makes IPPs bear much of the risk associated with this uncertainty.[349] Interwest acknowledges that there "are some benefits to having at least some contract terms be non-negotiable" such as quicker processing time.[350] However, Interwest argues that it is better for the whole contract—or at least specific provisions—to be negotiable. Similar to CEI, Interwest goes through numerous problems with the proposed PPA terms and recommends they remain negotiable or be modified.[351] Interwest argues that if the Commission chooses to accept any portion of the conforming bid policy, it should explicitly incorporate all of the positions put forth by Interwest, CEI, and CIEA.[352]

403. Pivot Energy also recommends rejecting the conforming bid policy.[353]

404. We largely agree with Public Service regarding the need for, and potential benefits of, a conforming bid policy. The bid evaluation process in the 2021 ERP/CEP took much longer than the Commission's Rules anticipate, and Public Service had to seek multiple extensions of the deadline to file the 120-Day Report. One of the proffered reasons for these delays was the difficulty

[348] CEI's SOP at pp. 5-6.
[349] Interwest's SOP at pp. 7-8.
[350] Hr. Ex. 500, Sanger Answer, p. 22.
[351] *See* Hr. Ex. 500, Sanger Answer, pp. 25-52.
[352] Interwest's SOP at pp. 8-9.
[353] Pivot Energy's SOP at p. 18.

Public Service had evaluating numerous bids with proposed modifications to the model PPA contracts. In the Commission's Phase II Decision in the 2021 ERP/CEP, we observed that having the Company and IE attempt to determine on an *ad hoc* basis during the bid evaluation process which terms of the PPAs are negotiable is a challenging situation, especially considering that the Commission already addresses many core issues of the model PPAs in Phase I and the fact that in Phase II the Company and IE are called upon to equitably evaluate numerous bids.[354] Even after a final portfolio of resources was approved, there were significant delays in the negotiation and execution of most PPAs. These delays contributed to the need for the CEP Delivery Decision. Even after the CEP Delivery Decision, however, the process of negotiating and executing PPAs remained relatively slow.

405. Adopting a conforming bid policy will simplify the process of evaluating and modeling numerous bids because Public Service and the IE will not need to evaluate the impacts of various redlines to the PPAs. Moreover, the conforming bid policy will likely prevent a protracted negotiation process in which Public Service and the respective IPPs go back and forth on fundamental contract terms such as the amount of security or the definition of *force majeure*. We acknowledge arguments from various intervenors that a conforming bid policy will reduce flexibility at the same time that the challenges and uncertainties regarding developing new resources is increasing. Based on our experience in the 2021 ERP/CEP, however, a fully negotiable PPA was insufficient to avoid issues associated with changing conditions.

406. To facilitate the development of minimally negotiable PPAs,[355] we find it appropriate to resolve several of the key disputed issues, including provisions regarding security

[354] Phase II Decision at ¶¶ 292-293 issued in the 2021 ERP/CEP (Jan. 23, 2024).

[355] Consistent with the Company's proposal, post-selection parties may still negotiate minor issues in the PPAs, so long as doing so is not inconsistent with our directives on the key substantive issues.

requirements, events of default, *force majeure*, and transfer limitation. Within 14 days of this Decision, Public Service shall submit updated versions of each PPA that incorporates our directives. The Company must include both clean and redline versions. Intervenor comments on the revised PPAs, including redlined versions with proposed language, are due within 14 days of the Company's submission of the revised PPAs.[356] Any reply comments and updated PPA language from Public Service are due within 14 days after intervenor comments. The Commission will target issuing a decision within 21 days of the reply comments and may convene a technical conference, as necessary. This will result in a final set of PPAs to which bids must conform for the base RFP.

407. Our resolution of the key disputed issues are set forth below. As set forth above, the Company shall fully incorporate our below directives into the revised PPAs it files within 14 days of this Decision. Additionally, to ensure fair competition and to maximize ratepayer protections, the Commission will endeavor to ensure that utility-owned generation meet standards equivalent to those expected for PPAs.

1. Market Changes

408. The Model PPAs contain provisions that requires the IPP and Company to cooperate in good faith if Public Service enters a market that impacts the deployment of the resource. For instance, Section 5.3 in Volume 3, Appendix D2 (also present in Section 5.2 of Volume 3, Appendix D1) sets forth the following:

> a. If at any time during the Term, the Transmission Authority changes or the facilities at the Point of Delivery cease to be subject to the Transmission Tariff, the Parties shall cooperate in good faith to

[356] The Commission recognizes that potential requests for rehearing, reargument, or reconsideration ("RRR") may be concurrent with this proposed timeline. While a RRR request does not automatically stay a Commission decision, appropriate filings may request revision to this timeline, including through concurrently filed or included motion to extend timelines if needed or appropriate through resolution through RRR resolution.

facilitate the delivery of Energy, at the least possible cost to the Parties, consistent with this PPA to the extent possible.

b. If at any time during the Term, the Transmission Authority, the ERO or any other Governmental Authority with jurisdiction imposes an organized market or Company elects to join a regional transmission organization, or participate, or change its participation in, an organized market that changes the manner in which the Facility is scheduled and dispatched, the Parties shall cooperate in good faith to change their protocols for operation of the Facility accordingly, at the least possible cost to the Parties, consistent with this PPA to the extent possible.[357]

409. At a high level, Interwest argues that language should be added to this provision that limits the costs imposed on the IPP and requires a dispute resolution or mediation process if a disagreement arises. CEI argue for language that provides clarity to ensure that the project developer does not incur additional material costs as a result of the Company electing to join a regional transmission organization.[358]

410. In Rebuttal, the Company agrees to add a deductible concept in which the Company will reimburse required capital expenditures if they exceed a deductible equal to $25/KW of nameplate capacity, subject to Company approval.[359] More generally, Public Service argues that "[t]he developer's risk to meet its commitments despite changes by the Federal Energy Regulatory Commission, a market operator, or reliability entity as it relates to its facility or equipment, remains with the bidder to bear."[360]

411. In Surrebuttal, however, CEI continues to object even with the Company's offered compromise. CEI asserts that costs that are unknown and unable to be negotiated when the contract is signed are the responsibility of Public Service, including material costs that do not constitute

[357] Hr. Ex. 101, Att. JWI-3, Vol. 3, Appendix D2, pp. 18-19.
[358] *See* Hr. Ex. 2207, Att. JFP-2, p. 11.
[359] Hr. Ex. 2207, Att. JFP-2, p. 11.
[360] Hr. Ex. 120, Att. JLB-2, Rev. 1, p. 4.

capital expenditures. CEI asserts that joining a regional market is to the benefit of the Company and its customers, and those costs should not be imputed after the fact on the IPP project.[361]

412. We agree with the Company's proposal to create a cap on the developer's capital obligations regarding market changes. This approach is responsive to Interwest's request to limit the IPP's costs and provide bidders additional certainty. Given IPPs have little, if any, control over whether the Company enters a market, however, we find that the Company's proposed deductible amount is too high. Instead, to the extent any changes required in connection with market changes as set forth in the PPA require capital expenditures within the Facility, such reasonable expenditures will be reimbursed if they exceed a deductible equal to $10/KW of nameplate capacity. With the exception of capital expenditures, each party otherwise will bear its own costs.

2. Security Requirements

413. Article 11 covers the IPP's security requirements and Section 11.1(B) dictates the amount and timing of security as follows:

> Seller shall establish and fund the Security Fund in the amount of [insert $200/kW] multiplied by the number of kW in the Facility Nameplate Capacity], no later than thirty (30) Days following the Effective Date. Within five (5) Business Days following COD, the amount of the Security Fund shall be reduced to [insert $75/kW multiplied by the number of kW in the Facility Nameplate Capacity].[362]

414. Interwest argues the pre-COD security is excessive and should be reduced to $100-$125/kW, and that the Seller should only be required to replenish the Security Fund post-COD. CEI argues that alternative commercially reasonable approaches to security, such as performance bonding or a letter of credit, should be used instead of the proposed security requirements.[363]

[361] Hr. Ex. 2207, Att. JFP-2, p. 11.
[362] Hr. Ex. 101, Att. JWI-3, Vol. 3, Appendix D1, p. 29.
[363] Hr. Ex. 120, Att. JLB-2, Rev. 1, p. 27.

415. In Rebuttal, the Company makes certain concessions but generally maintains its position, arguing that the security amounts cannot be changed after bid selection as that would undermine the integrity of the RFP. As for the amount, Public Service states it can agree to reduce the Pre-COD security from $200/kW to $150/KW and can also agree to modify the contract so pre-COD replenishment is only required when security falls to 50 percent or below the initial level. The Company notes that the model contract as written already allows Letters of Credit as an acceptable form of security.[364]

416. In its Surrebuttal, CEI continues to oppose the security provisions, characterizing them as "a major issue."[365] CEI argues the Company's concessions are insufficient to account for the other problematic liquidated damages language in Section 12 and that it is impossible to negotiate these components individually.

417. We agree with Public Service that the security provisions in the PPAs should be nonnegotiable. Security provisions have significant implications for many other portions of the PPAs. Developers incur costs to maintain the security fund, and the size of the security fund also changes the amount of risk a developer assumes when it executes a PPA. Conducting an apples-to-apples comparison of bids for new-build projects would be difficult if those bids assume significantly different security provisions.

418. While we agree Article 11 should be nonnegotiable, we disagree with the Company's proposal for a pre-COD security of $200/kw. Instead, the initial Security Fund in Section 11.1(B) shall be reduced to $125/kw, consistent with the recommendation from Interwest. This level also matches the amount used in the model PPAs in the 2021 ERP/CEP.[366] We adopt the

[364] Hr. Ex. 120, Att. JLB-2, Rev. 1, pp. 28-29.
[365] Hr. Ex. 2207, Att. JFP-2, pp. 20-21.
[366] Hr. Ex. 2212, p. 130.

Company's post-COD Security Fund of $75/kw. We further adopt the concession Public Service made in Rebuttal that pre-COD replenishment is only required when security falls to 50 percent or below the initial level.

419. Finally, Public Service shall make corresponding changes throughout the PPAs to reflect the lower security amount. For example, in Section 12.2(D), the liquidated damages amount is set at $100/kw. In Rebuttal, the Company acknowledges that if the security fund is reduced to $150/kw, the liquidated damages in Section 12.2(D) would change to $75/kw. Because we set the pre-COD security fund to $125/kw, the liquidated damages in Section 12.2(D) must be modified to $62.5/kw.

3. Events of Default

420. Section 12.1(A) lists several events that could cause default if not cured. These include events like if the IPP declares bankruptcy, fails to obtain and maintain insurance, or if any of the representations the IPP makes in the contract are materially false.

421. Public Service argues that it expects developers to perform and is unwavering in protecting its customers given the likely consequences if they do not. The Company asserts that the default provisions in Section 12.1(A) are reasonable and are designed to ensure competent, effective, and diligent development and operations. [367]

422. Interwest and CEI argue the Company has overly aggressive definitions of default and specifically flag provisions concerning breach of the interconnection agreement, committed energy requirements, and availability factor.

[367] Hr. Ex. 120, Att. JLB-2, Rev. 1, p. 4.

423. In Rebuttal, Public Service offers concessions on certain of these provisions but maintains its position on others.[368] In Surrebuttal, CEI asserts that Section 12 "remains a major issue," even after the Company's concessions and that "the Company has very aggressive definitions of default."[369]

424. While we agree that Section 12.1(A) should be nonnegotiable, we direct the Company to make several changes to the PPAs. First, Section 12.1(A)(4) states the following:

> Any representation or warranty by Seller that materially affects its ability to perform this PPA (a) is proven to have been false in any material respect when made or, (b) ceases to remain true in all material respects during the Term, provided however, that a representation or warranty that ceases to remain true due to a change in Applicable Law shall not be considered an Event of Default.[370]

425. Public Service shall strike Section 12.1(A)(4)(b) from the PPAs such that Section 12.1(A)(4) reads: "Any representation or warranty by Seller that materially affects its ability to perform this PPA is proven to have been false in any material respect when made." We find 12.1(A)(4)(b) unreasonable in that representations and warranties that cease to be true over the course of the contract (*e.g.* 15-20 years) could result in a default. Moreover, the model PPAs from the 2021 ERP/CEP do not include this future-looking default provision,[371] and Public Service has not met is burden of showing why this concept is now necessary.

426. We further direct changes to the provisions in Section 12.1(A) establishing the availability requirements. Interwest raised concerns with the Company's proposal to measure the capacity availability factor for an event of default over 12 months. Interwest instead argues the industry standard is to measure the capacity availability factor over 24 months.[372] In its Rebuttal,

[368] Hr. Ex. 120, Att. JLB-2, Rev. 1, pp. 29-31.
[369] Hr. Ex. 2207, Att. JFP-2, p. 22.
[370] Hr. Ex. 101, Att. JWI-3, Appendix D2, p. 44.
[371] Hr. Ex. 2212, p. 134.
[372] Hr. Ex. 2207, Att. JFP-2, p. 22.

the Company asserts the PPAs do provide developers 24 months because developers have a year to cure before the capacity availability factor would trigger a default.[373]

427. We direct Public Service to revise the PPA provisions regarding availability requirements (including for renewables, hybrid, and storage-only PPAs) to match the equivalent availability requirements that were included in the model PPAs from the 2021 ERP/CEP. For solar and wind availability requirements, we specifically direct Public Service to use the availability requirements agreed upon as part of the 2021 ERP/CEP USA.[374]

4. Specific Performance

428. Section 12.1(D) entitles the Company to specific performance, in addition to its other contractual remedies: "In addition to the other remedies specified herein, upon any Event of Default of Seller under this Section 12.1, Company may elect to treat this PPA as being in full force and effect and Company shall have the right to specific performance."

429. Interwest and CEI oppose this provision, arguing that it is not a reasonable, market term for the Company to be able to force the Seller to perform.[375] In Rebuttal, the Company agreed to remove Section 12.1(D) so long as the remedies in Section 12.1(B) remain unchanged.[376] Under Section 12.1(B), the Company can seek actual damages, offset payment due to the Seller, and draw damage from the security fund.[377] In Surrebuttal, CEI argues it is unreasonable to condition the removal of Section 12.1(D) on maintaining the damage provisions in Section 12.1(B), especially given the "extreme amounts" of liquidated damages.[378]

[373] Hr. Ex. 120, Att. JLB-2, Rev. 1, p. 29.
[374] *See* 2021 ERP/CEP USA, Att. 3.
[375] Hr. Ex. 2207, Att. JFP-2, p. 23.
[376] Hr. Ex. 120, Att. JLB-2, Rev. 1, p. 33.
[377] Hr. Ex. 101, Att. JWI-3, Appendix D2, p. 47.
[378] Hr. Ex. 2207, Att. JFP-2, p. 23.

430. We direct Public Service to remove Section 12.1(D). We agree with CEI and Interwest that specific performance is an out-of-market remedy in this context. While we are not directing Public Service to modify the language in Section 12.1(B), we note that our prior directives lowering the amount of required security impacts the force of Section 12.1(B).

5. Default Option

431. Section 12.1(E) provides another remedy to Public Service if the Company determines that there has been an event of default under Section 12.1. As opposed to obtaining a portion of the security deposit or seeking additional monetary damages, Section 12.1(E) provides Public Service with a default option in which it can unilaterally purchase and own the project:

> If Company terminates this PPA under this Section 12.1 following COD, then, at any time within ninety (90) Days following such termination, Company may give notice to Seller of Company's intent to purchase the Facility from Seller (a "Default Option Preliminary Exercise Notice").[379]

432. Interwest and CEI both strongly oppose the Default Option in Section 12.1(E), arguing that it is unreasonable and not aligned with market terms. They assert this provision would incentivize Public Service to terminate PPAs so that the Company could use Section 12.1(E) to takeover and own the facility.[380] In Rebuttal, the Company maintains its support for Section 12.1(E). Public Service asserts that the provision simply provides the Company with an alternate path to offset damages. The Company further asserts 12.1(E) does not provide an improper incentive because the Company is not in control of Seller defaults.[381] In Surrebuttal, CEI asserts the default option under Section 12.1(E) is new to the Colorado marketplace and is extremely anti-competitive in favor of the Company.[382] During the evidentiary hearing, Company witness Mr.

[379] Hr. Ex. 101, Att. JWI-3, Vol. 3, Appendix D1, p. 35.
[380] Hr. Ex. 2207, Att. JFP-2, p. 24.
[381] Hr. Ex. 120, Att. JLB-2, Rev. 1, p. 33.
[382] Hr. Ex. 2207, Att. JFP-2, p. 24.

Bornhoffen acknowledged the model PPAs in the 2021 ERP/CEP did not have a similar default option. Mr. Bornhoffen continued to defend the default option, however, arguing that lenders appreciate these types of provisions.[383]

433. We agree with Interwest and CEI and direct Public Service to strike the default option provisions from the PPAs. At the very least, the default option increases the risk that Public Service would be incentivized to determine that an event of default under Section 12.1 has occurred. This would allow the Company to acquire the project outright instead of seeking monetary damages from the IPP. Public Service acknowledges this is a "new" provision that it did not have in the 2021 ERP/CEP Model PPA, but the Company has not established why a default option is now necessary.

434. We are unpersuaded that the risk of losing IPP resources justifies the default option. The PPAs already provide Public Service a Right of First Offer ("ROFO") in Section 19.2. More generally, if Public Service was concerned about losing the project it could allow the PPA to remain in effect but pursue any appropriate monetary damages.

6. Construction and Development Milestones

435. In addition to the events of default listed in Section 12.1, Section 12.2(A) provides that the IPP will be in default if it fails to meet the COD target date or if the project fails to achieve any Critical Path Development ("CPD") Milestones. In addition, Section 12.2(A) allows Public Service to collect liquidated damages of $250/MW of nameplate capacity for each day of delay.[384] The CPD milestones are defined in Section 4.1 and include acquisition of necessary permits, execution of all construction contracts, and closing of project financing. [385]

[383] Hr. Tr. June 17, 2025, pp. 236-38.
[384] Hr. Ex. 101, Att. JWI-3, Vol. 3, Appendix D1, p. 36.
[385] Hr. Ex. 101, Att. JWI-3, Vol. 3, Appendix D1, p. 9.

436. Interwest and CEI both object to the addition of CPD Milestones and the associated risk of default and liquidated damages. For instance, Interwest argues that damages should not be imposed for missing milestones, unless the milestone is the target COD. [386]

437. In Rebuttal, the Company argues that the CPD Milestones include only those milestones that if not achieved by a certain date puts the project COD in serious jeopardy. Public Service asserts knowing whether a project is sufficiently correcting the issue is imperative to the Company's near-term planning efforts. However, the Company states it would be willing to combine the milestones to be a single milestone whereby the bidder must have executed their supply contracts, obtained their construction permit, and closed on construction financing no less than 30 days following the date designated in Seller's construction schedule. [387] More generally, the Company argues that a firm and reliable construction schedule is necessary to ensure timely delivery of a project. Milestones allow the Company to identify and act when projects are behind schedule and at risk of delayed in-service. [388]

438. In Surrebuttal, CEI disagrees with the Company's concession to combine milestones and maintains that missing early milestones should not risk triggering a full default. CIE asserts that, even if eventually refunded, paying liquidated damages will impact projects security, replenishment, and potentially its financing requirements.[389]

439. We agree with Interwest and CEI and direct Public Service to remove the CPC development milestone concept from the PPAs. The PPAs set strict penalties if developers do not meet their COD. In addition, the PPAs require developer to set out several construction milestones and requires the developer to "use Commercially Reasonable Efforts to achieve the milestones set

[386] Hr. Ex. 2207, Att. JFP-2, p. 7.
[387] Hr. Ex. 120, Att.JLB-2, p. 9.
[388] Hr. Ex. 120, Att. JLB-2, p. 4.
[389] Hr. Ex. 2207, Att. JFP-2, p. 7.

forth in Exhibit B - Construction Milestones and shall notify Company promptly following achievement of each such Construction Milestone."[390] Given this existing requirement, it is unclear how the new CPD Milestones are necessary for the Company to be able to identify when a project is falling behind. In addition, the CPD Milestones concept provides for a finding of default and the imposition of liquidated damages, which a developer does not face if it fails to meet a regular construction milestone. Public Service has not established, however, how terminating the PPA or imposing significant liquidated damages for missing CPD Milestones will help the project complete construction, especially given that the penalties for missing the COD would seem to properly incentivize a developer for finishing construction on time. This concept was not included in the 2021 ERP/CEP Model PPA, and Public Service has again failed to establish why it should be a required provision in the current Model PPA.

440. While we eliminate the CPD Milestones concept, this does not alter the penalties for missing the COD. In addition, going forward we intend to hold Company-owned projects to similar standards as PPA projects both in terms of economics and timing. In other words, given there are strict consequences for IPPs if their projects fail to meet their target COD or budget, Public Service should likewise face strict consequences if utility-owned projects are delayed or over budget.

7. Exit Clauses

441. Section 12.2(D) states that failure to cure a COD Delay will be an event of default that would allow Public Service to terminate the PPA and collect a certain amount of liquidated damages:

[390] Hr. Ex. 101, Att. JWI-3, Vol. 3, Appendix D1, p. 9.

> Failure to cure a CPD Delay or COD Delay within the applicable cure period set forth in Section 12.2(B) shall be an Event of Default by Seller. Upon such an Event of Default, Company may (i) terminate this PPA immediately upon notice to Seller, without penalty or further obligation to Seller except as to costs and balances incurred prior to the effective date of such termination, and (ii) in connection therewith, in addition to accrued Liquidated Delay Damages but in lieu of Actual Damages for the balance of the Term, collect from Seller liquidated damages therefor in the amount of [*insert $100/kW x Facility Nameplate Capacity*].[391]

442. As with the other portions of Section 12, CEI argues that this provision does not reflect the market and should be removed. CEI asserts the liquidated damages called for in other parts of the agreement should be adequate if structured correctly. [392]

443. The Company characterizes this provisions as a convenience exit in which if the developer chooses to abandon the project, the Seller must reimburse the Company and forego 50 percent of its security. The Company argues that it cannot agree to eliminating the damages associated with the provision as that would give the developer a free exit clause or rights to walk away from the contract. [393]

444. We agree with Public Service that IPPs should not be allowed to default on the PPA and walk away with little consequence. In this vein, the Company's suggestion that liquidated damages equal to 50 percent of the security deposit (in addition to costs/damages accrued prior to the termination date) is a reasonable consequence for failing to meet the COD. We note a substantially similar provision was contained in the 2021 ERP/CEP model PPA

445. To be clear, however, we do not approve Section 12.2(D) verbatim. As discussed above, Public Service must eliminate the CPD Milestones concept from the PPAs,

[391] Hr. Ex. 101, Att. JWI-3, Appendix D1, p. 37.
[392] Hr. Ex. 120, Att. JLB-2, p. 36.
[393] Hr. Ex. 120, Att. JLB-2, p. 36.

and our directive to reduce the amount of necessary security impacts the level of liquidated damages in Section 12.2(D).

446. Finally, we reiterate our intent that PPA and utility-owned projects will meet similar expectations. Given that IPPs face significant consequences if they are no longer able or willing to move forward with a project under the terms of an executed PPA, Public Service should likewise not be able to freely walk away from utility-owned projects.

8. Force Majeure

447. The PPAs provide the following definition of force majeure:

> For purposes hereof, "Force Majeure" means an event or circumstance that prevents a Party from performing its obligations under this PPA, which event or circumstance (i) was not anticipated as of the Effective Date, (ii) is not within the control of or the result of the fault or negligence or failure to follow Good Utility Practices of the Party claiming excuse, and (iii) which by exercise of due diligence and foresight could not reasonably have been avoided….[394]

448. Section 14.1 then goes on to list several items that expressly do *not* constitute force majeure. These include failure to obtain permits, supply chain disruptions, and changes to applicable law.

449. Interwest and CEI both oppose the current force majeure language. CEI, for example, notes that FM currently does not recognize change in law risks. CEI states that force majeure is a critical PPA term and should be further negotiated by the parties. Interwest argues the phrase "unless such acts or omissions are themselves excused by reason of Force Majeure as defined in this Section 14.1" should be added to subsections 14.1(A), 14.1(C), and14.1(D).

[394] Hr. Ex. 101, Att.JWI-3, Appendix D1, pp. 42-43.

Interwest also recommends extending the time within which parties have to claim force majeure and including labor strikes or other labor disruptions in the definition of force majeure. [395]

450. In Rebuttal, Public Service largely opposes the various suggested revisions to the force majeure language, arguing that force majeure should only include only those circumstances that are truly unpredictable or unforeseeable. However, the Company does agree to modify the notice requirement to start the clock on the date when Seller "was aware or should have been aware" of the Force Majeure event, so long as the period of delayed awareness is no longer than 90 days after the date of occurrence.[396]

451. In Surrebuttal, CEI maintains that that impacts to the supply chain should constitute force majeure, reasoning that it is unrealistic in this national and global environment to attribute all of the supply chain risk to sellers. [397] CEI similarly argues that placing all change-in-law risk on Sellers is unreasonable in the current environment.

452. Similar to the exit clause concept discussed above, we agree with Public Service that the PPAs should strictly limit when a developer can be excused from performance by reason of force majeure. Nevertheless, we direct Public Service to make several modifications to the force majeure definition. First, we adopt Interwest's recommendations and add the following language to subsections 14.1(A), 14.1(C), 14.1(D): "unless such acts or omissions are themselves excused by reason of Force Majeure as defined in this Section 14.1." We also adopt Interwest's recommendation that the period within which notice is required under Section 14.2 starts when the party becomes aware of the force majeure event not when it occurs. We deny the Company's suggestion in Rebuttal that such period of delayed awareness cannot be

[395] Hr. Ex. 2207, Att. JFP-2, p. 29.
[396] Hr. Ex. 120, Att. JLB-2, pp. 39-40.
[397] Hr. Ex. 2207, Att. JFP-2, p. 1.

longer than 90 days after the date of occurrence. In the 2021 ERP/CEP the relevant provision simply required "prompt notice." In addition, Public Service shall strike Section 14.1(L), which carves out labor strikes, slowdowns, work stoppages, or other labor disruptions from the definition of force majeure. Interwest has put forth evidence that other utility PPAs, such as PacifiCorp's 2022 RFP, include these types of events as force majeure.[398] The Company's argument that work stoppages within a developer's supply chain are the developer's responsibility is unpersuasive.

453. Moreover, we disagree with Section 14.1(H)'s exclusion of delays or failure of the transmission authority: "any delay or failure by the Transmission Authority to perform its obligations under the Interconnection Agreement or any curtailment or reduction in deliveries by the Transmission Authority."[399] Even by the Company's own standard, it is difficult to see why delays from the transmission authority (likely Public Service) would not be unpredictable or unforeseeable to a developer. This concept was not included in the force majeure definitions in the 2021 ERP/CEP PPAs.[400] The Company has failed to explain why developers should be liable under the PPA for delays and failures on the part of the transmission authority. Not only do we disagree with Section 14.1(H)'s exclusion of these types of events, we direct Public Service to modify the PPAs such that "any delay or failure by the Transmission Authority to perform its obligations under the Interconnection Agreement or any curtailment or reduction in deliveries by the Transmission Authority" expressly constitutes an event of force majeure.

454. We empathize with CEI's arguments that by excluding change in law from the definition of force majeure, the Company places the risk of future tariffs and changes in federal law on IPPs. At the same time, we are reluctant to endorse such a broad expansion of force majeure

[398] Hr. Ex. 500, Sanger Answer, p. 50.
[399] Hr. Ex. 101, Att. JWI-3, Appendix D1, p. 43.
[400] Hr. Ex. 2212, p. 142.

by including as events of force majeure changes of federal law or tariff policy. Instead, we direct Public Service to include in the revised PPAs language that would enable Sellers to avoid pre-COD default, liquidated damages, and other seller obligations if there was a Commission-recognized change in law. This language should propose a notice and comment process where parties could request a change-in-law finding or notify the Commission that the parties agree that a change in law has occurred. This process for recognizing changes in law will not include changing tariffs, which we address separately below in Section P.

9. Transfer Limitations

455. Under Section 19.3 of the Model PPA, whenever an IPP wants to sell a project after the COD but before then end of the PPA term, it must offer Public Service a Right of First Offer ("ROFO"). After notice of the ROFO, the Company has 60 days to agree to purchase the project. If the Company does not agree to purchase the project, then the IPP can sell the project to a third party, but only "on terms that a reasonable person would determine are not more favorable to such buyer than the terms offered to the Company in the ROFO Notice."[401]

456. Under Section 19.4, the IPP must give Public Service at least 90 days' notice of any Pending Facility Transaction ("PFT Notice") that does not otherwise trigger Company's ROFO rights under Section 19.3. At a high level, the PFT Notice requirement is triggered by events such as the IPP attempting to sell to its equity interests to a third party. If the IPP fails to timely provide the PFT Notice, the Company is entitled to liquidated damages in the amount of $5/kw. [402]

457. Interwest argues that ROFO or any similar provision are disfavored by developers and financers and can thus limit the pool of potential buyers and can delay sales. Interwest adds

[401] Hr. Ex. 101, Att. JWI-3, Vol. 3, Appendix D1, p. 47.
[402] Hr. Ex. 101, Att. JWI-3, Vol. 3, Appendix D1, pp. 47-48.

that every developer is different regarding what it is willing to accept related to these ROFO provisions.[403]

458. CEI similarly opposes the ROFO provision, arguing that it is more commercially reasonable to require a right of last offer ("ROLO") as the Seller can price the project for the benefit of the Seller. CEI argues that if a ROFO is included, it should set a period of time by which parties must agree or execute any transaction. CEI adds the "not more favorable" provision in Section 19.3 is undefined and should be struck.[404]

459. In Rebuttal, Public Service argues that while the PFT and ROFO provision may not align with the IPP's business model, they align with the Company's business model to serve its customers reliably. Public Service asserts it needs to be made aware when a project is going to be sold to a third-party buyer for reliability and planning reasons. The Company states the Model PPAs in 2016 and 2021 contained PFT and ROFO terms, and IPPs were able to successfully bid in those solicitations. According to the Company, these are reasonable and practical requirements that in no way lessen the developer's opportunity to seek the highest and best offer for its project.[405]

460. In Surrebuttal, CEI maintains its opposition to the ROFO and PFT provisions.[406]

461. We find persuasive the Company's point that the ROFO and PFT provisions have been included in the Model PPA of the last two ERPs. Neither Interwest nor CEI contests this point in Surrebuttal. We thus direct that the ROFO and PFT concepts be included in the PPAs, but bidders are allowed to negotiate the details of certain modifications. Specifically, the ROFO provisions must include a period of time by which parties must agree to execute any transaction. In addition, the ROFO provision must be converted to a ROLO. Alternatively, the ROFO must

[403] Hr. Ex. 500, Sanger Answer, p. 47.
[404] Hr. Ex. 2202, Pierce Answer, pp. 54-55.
[405] Hr. Ex. 120, Att. JLB-2, pp. 34-35.
[406] Hr. Ex. 2207, Att. JFP-2, p. 31.

require the use of third-party appraisals to ensure fair valuation of the project. These modifications are responsive to CEI's concerns about the "not more favorable" language. Bidders should be allowed to negotiate the specific wording that implements these concepts.

462. Similarly, for the PFT provisions in Section 19.4, the PFT Notice concept shall be included in the PPAs, but bidders and the Company may negotiate the exact instances in which the PFT Notice requirement is triggered and whether a breach of Section 19.4 entitles the Company to liquidated damages.

463. In addition to the transfer limitations currently included in the PPAs, we direct Public Service to include in the revised PPAs an additional provision creating a ROLO to renew PPAs at the expiration of their terms. After Public Service customers have supported PPA projects over the course of the PPA term, Public Service should have an opportunity to renew the PPA rather than having the project sign a new PPA with a different utility.

10. Existing PPAs

464. Onward Energy urges the Commission to reject Public Service's plans to apply the conforming bid policy to existing PPA resources. Onward argues that when applied to existing facilities the conforming-bid policy does not provide any significant benefit to Public Service's customers and instead increases costs, transactional complications, and uncertainty. Onward asserts Public Service's model PPA is simply not structured with an existing facility in mind. Onward asserts numerous provisions in the model PPA are intended to address pre-operational risks that are inapplicable to an existing facility.[407]

465. Rather than applying the conforming bid policy to existing resources, Onward argues that such existing resources should be allowed to offer a bid based on updates to the existing

[407] Onward's SOP at p. 5.

PPA. Onward acknowledges that existing resources should be required to compete with other generation options on price and reliability metrics but maintains that Public Service should not be erecting unnecessary barriers to re-contracting with existing resources.[408]

466. In Rebuttal, the Company opposes arguments from Onward that there should be an exception to the conforming bid policy for existing PPAs. The Company acknowledges that existing resources can provide significant benefits but asserts that many of the original provisions of a pre-existing PPA may be outdated. The Company further argues that certain provisions in pre-existing PPAs, if maintained, would be unfair to the new construction bidders. For example, the Company states it is not uncommon to find lower security requirements in older PPAs, and that bidder with less security can submit lower bids. The Company asserts it is unfair to grant one bidder a more favorable term without offering the same to every bidder as a part of the RFP.[409] The Company also asserts that Onward's arguments that numerous sections or exhibits of the model PPA would require significant modifications are exaggerated.[410]

467. In its SOP, Onward asks the Commission to expressly state that Public Service is free to deviate from the model PPA terms when accepting bids from and negotiating with existing resources, where such terms either reflect an attempt to mitigate risk associated with pre-operational projects, where such terms either reflect an attempt to mitigate risk associated with pre-operational project development.[411]

468. For the reasons set forth by Onward, we reject the Company's proposal to apply the conforming bid policy to existing resources. Instead, we direct Public Service to make clear in the RFP that existing resources may use their existing PPA as a baseline for crafting their bids.

[408] Hr. Ex. 1100, Spurgeon Answer, pp. 9-10.
[409] Hr. Ex. 120, Bornhofen Rebuttal, pp. 28-29.
[410] Hr. Ex. 120, Bornhofen Rebuttal, pp. 26-27.
[411] Onward's SOP at pp. 5-6.

While IPPs of existing resources and Public Service can negotiate certain necessary updates, the baseline for such negotiations should be the existing PPA. Existing PPA resources may have unique benefits, especially in comparison to new Company-owned fossil generation, which could carry concerning stranded asset risk, which warrants a thoughtful approach to such negotiations and terms. The additional flexibility will hopefully encourage existing projects to bid into the solicitations.

O. Phase II Modeling Methodologies and Assumptions and Processes

1. Best-in-class and Phase II Modeling Updates

a. Party Positions

469. The Company proposes to keep the same best-in-class process for reducing the number of bids that proceed to computer-based modeling as was used in the 2021 ERP/CEP. The Company explains it will evaluate each technology class separately by utilizing the partial unit optimization feature of EnCompass to solve for the least-cost portfolio comprised solely of that technology class. Projects will be selected to be advanced further in this "best in class" initial selection process by determining if the model selected any partial amount of a project as part of a least-cost solution.[412]

470. In its Answer, Staff raises concerns regarding the use of the best in class process and recommends Public Service be required to notify Staff of all modeling changes/challenges encountered in Phase II, update Staff if the company decides to use the best-in-class process in Phase II, and consult with Staff should further due diligence eliminate more bids after the best-in-class process.[413] More broadly, Staff recommends that the Commission require the

[412] Hr. Ex. 102, Landrum Direct, Rev. 1, p. 60.
[413] Hr. Ex. 2604, Abiodun Answer, p. 12.

Company to keep Staff apprised of any modeling changes after the Phase I decision is made. Staff recounts that in the 2021 ERP/CEP the Company modified the Phase II modeling in ways that were not agreed upon in the 2021 ERP/CEP USA and did so without informing the Commission.[414] In its SOP, Staff maintains its recommendations in Answer that the Company should be required to inform Staff of modeling changes between Phase I and actual Phase II modeling.[415]

471. Similar to Staff, CIEA argues the Company should be required to notify the Commission and parties if the EnCompass model will not "solve" during the bid evaluation process. CIEA recommends the Commission order Public Service to submit status reports if the bid evaluation effort encounters difficulties to ensure that the Commission and parties are aware if the bid evaluation efforts are "coming off the rails."[416] CIEA also argues for two modifications to the Company's best-in-class process to include consideration of transmission costs. The first would be to conduct partial optimization runs among projects located inside the Denver constraint, ensuring that some subset of these pass on to computer modeling. The second modification would be to sort projects not only by lowest PVRR, but also by transmission costs, so that some projects that do not have the lowest costs could still be forwarded on to computer modeling if they have lower interconnection or delivery costs.[417]

472. In Rebuttal, Public Service specifically opposes CIEA's recommendation to notify the parties and Commission if EnCompass fails to solve during the bid evaluation process. The Company states it will resolve problems and solutions in the Phase II modeling process with oversight from the IE as it has in previous ERPs. Public Service argues that, not only does it expect to avoid many of the challenges it faced during the 2021 ERP/CEP, such a notification process

[414] Hr. Ex. 2604, Abiodun Answer, pp. 5, 12.
[415] Staff's SOP at p. 18.
[416] Hr. Ex. 700, Monsen Answer, Rev. 1, pp. 82-83.
[417] CIEA's SOP at p. 29.

would slow down the Phase II process.[418] Public Service does not appear to address Staff's related suggestion or CIEA's recommended changes to the best-in-class process.

b. Findings and Conclusions

473. The best-in-class process was one of the unvetted changes Public Service made to the Phase II modeling in the 2021 ERP/CEP after the CEP Phase I Decision. While we agree with Public Service that such a process may be necessary to timely model numerous bids, eliminating bids through the best-in-class process does come with risks. We agree with CIEA's recommendations to incorporate transmission and locational considerations into the best-in-class process. Even if these additional considerations slow down the Phase II modeling, we believe this is worth the risk of suboptimal portfolio results. For example, under the current approach Public Service may evaluate all storage bids at once under the best-in-class process and thereby eliminate all but a small group of the lowest-cost storage bids. Storage bids within the Denver Metro constraint may be eliminated at this step if such bids have higher siting costs compared to storage bids farther away from the Denver area. This example demonstrates why additional guardrails and transparency in best-in-class process are appropriate.

474. Accordingly, we adopt CIEA's recommendations and direct Public Service to ensure that the best-in-class modeling process (1) includes partial optimization runs among projects located inside the Denver constraint, ensuring that some subset of these pass on to computer modeling, and (2) sorts projects not only by lowest PVRR, but also by interconnection transmission costs.

475. Regarding arguments from Staff and CIEA that Public Service should be required to provide certain modeling updates, it is important to the Commission that there is more

[418] Hr. Ex. 118, Landrum Rebuttal, p. 72.

transparency and integrity in the Phase II modeling process. As both Staff and CIEA note, in the 2021 ERP/CEP the Company made several unvetted modeling changes after the CEP Phase I Decision. These include introducing the best-in-class process, the reliability rubric, and assertions that no portfolio could meet reliability requirements unless the portfolio included new thermal generation at specific locations.[419] These unvetted changes caused certain parties to question the validity of the Phase II modeling and allege the Company's Phase II modeling was inconsistent with the Commission's CEP Phase I Decision.

476. Learning from the CEP process, here we grant Staff's recommendations and direct Public Service to inform Staff of the following modeling updates in Phase II as they occur: (1) Modeling changes and challenges encountered between this Decision and actual modeling in Phase II; (2) the Company's modeling decisions regarding application of the best-in-class modeling to manage the pool of bids; and (3) the elimination of bids caused by due diligence after the best-in-class process. Public Service does not seem to address these recommendations, although the Company opposes similar, but more stringent, recommendations from CIEA because they may slow down the Phase II process. The Commission is also wary of slowing down the Phase II modeling but trust that Staff can appropriately discern which modeling updates and changes are necessary and appropriate and which modeling updates require party and Commission feedback.

477. In addition to Staff's recommendations, if Public Service is or becomes aware of any specific system requirements that could relate to types of generation or geographical preferences, the Company shall make that information available to all bidders immediately. If the RFP has already issued, then the Company must notify Staff immediately. We are concerned

[419] Public Service's Response Comments on the 120-Day Report, p. 29, in the 2021 ERP/CEP.

about a Phase II process in which the Company is the only bidder that understands where there is a need or preference for a certain specific resource.

478. We reject CIEA's related request to require Public Service to notify all parties and the Commission or submit status reports if the bid evaluation effort encounters difficulties. Given the numerous intervenors active in this Proceeding and the other demands on the Commission's time and resources, such a process would likely cause damaging delays.

2. Assumptions regarding Existing and Planned Thermal Units

a. Party Positions

479. In its Phase II modeling, Public Service must make certain assumptions regarding a planned CT (*i.e.*, the 200 MW Fort Lupton CT proposed as part of the 2021 ERP/CEP) as well as the Plains End unit gas-fired resource. The Company also seeks Commission approval to extend the life of Cherokee 4 from the end of 2027 to the end of 2028. According to Public Service, Cherokee 4 provides critical energy capacity, reserves, and significant system operations benefits, particularly related to reliability and relieving transmission congestion in the Denver metro area.

480. In its SOP, Staff recommends the Commission direct the Company to include the 200 MW Fort Lupton CT as part of its Phase II modeling assumptions and similarly assume that the resource acquisition of the Plains End unit is successful and reflect the longer asset life past the 2033 extension date in the Phase II modeling. Staff also recommends the Commission approve the Company's proposed delay in the retirement date of Cherokee Unit 4 from 2027 to the end of 2028.[420]

481. UCA largely mirrors Staff's recommendations and specifically requests in its SOP for the Company to include in the Phase II modeling the third CT from the CEP, the continuation

[420] Staff's SOP at pp. 17-18.

of Plains End, and the delayed retirement of Cherokee 4. Regarding Cherokee 4, UCA reiterates its recommendation that two CTs at that location would not only take advantage of the locational reliability and transmission benefits but could also help avoid the $1.8 billion Harvest Mile Chambers-Sandown-Cherokee ("HCSC") and the $379 million New Substation A at issue in Proceeding No. 24A-0560E.[421]

482. EJC recommends the Commission reject the Company's request to extend the life of Cherokee Unit 4 by one year and reject the UCA's proposals to build new gas units at the Cherokee site.[422] According to EJC, the Cherokee gas plant is located in a DI community in the north Denver area, near Elyria, Swansea, Globeville, and Commerce City. In addition to the gas plant, the Suncor oil refinery, I-25 and I-70, and several Superfund sites also pollute and harm the nearby communities. EJC asserts a 2021 Sierra Club report highlighted how the Cherokee gas plant contributes to environmental injustice. Because Cherokee Unit 4 emits large amounts of pollution into nearby DI communities, EJC asserts the Company should retire the unit as planned and not extend its life by a year. [423]

483. EJC also argues that Public Service should be prohibited from accepting gas bids for projects located in Pueblo County. EJC argues that this type of prohibition would provide equity, minimize impacts, and correct historical inequities for Pueblo. EJC suggests that developing bids for a gas plant in Pueblo would be inconsistent with the Commission's equity obligations. [424]

484. In Rebuttal, Public Service agrees with Staff's recommendations on Cherokee 4 and the new Fort Lupton CT. However, the Company disagrees regarding Plains End. The

[421] UCA's SOP at p. 23.
[422] EJC's SOP at pp. 25-26.
[423] Hr. Ex. 1700, Valdez Answer, pp. 33-35.
[424] Hr. Ex. 1700, Valdez Answer, pp. 29-30.

Company argues the extension of Plains End beyond 2033 could impact the final resource mix selected, especially units that would achieve COD in 2031. In addition, under the Phase II Framework, the extension of the Plains End unit would occur during the Supplemental RFP RAP. Public Service thus argues that the Plains End unit should compete with other bids in the JTS Supplemental RFP to ensure an optimal resource portfolio is acquired moving forward.[425]

b. Findings and Conclusions

485. We grant Staff's recommendations, which UCA mirrored, regarding the inclusion of the 200 MW Fort Lupton CT, the one-year extension of Cherokee Unit 4, and the assumption that the resource acquisition of the Plains End unit is successful and the unit continues past the 2033 extension date.

486. The only recommendation that the Company contests is the assumption that Plains End will continue. We find both of the Company's arguments to be unpersuasive. The Phase II modeling must make an assumption either way about whether Plains End remains on the system past 2033. Given the attractiveness of extending existing gas-fired units versus building new gas plants, the noted cost increases and supply issues with new CTs, and the projected need for new capacity, the best assumption is that Plains End continues past 2033.

487. Regarding delaying the retirement date of Cherokee Unit 4 from 2027 to the end of 2028, we reject EJC's request to deny the one-year life extension. The Commission acknowledges EJC's points about Cherokee Unit 4 being located in a DI community. Nevertheless, the record contains considerable evidence that, looking at a system as a whole, including potential impacts to reliability and ratepayers, extending the life of the existing plant is the best available option.[426]

[425] Hr. Ex. 118, Landrum Rebuttal, p. 81.
[426] *See* Hr. Ex. 105, Siebenaler Direct, Rev. 1, pp. 71-78.

488. We similarly reject EJC's request to prohibit gas bids in Pueblo County. It would be premature for the Commission to determine in Phase I that DI impacts associated with any gas project in Pueblo County outweigh the potential benefits of a gas project, including helping to ensure the Pueblo community is afforded a just transition.

3. Depreciation of Gas Units, Hydrogen Conversion Costs, Etc.

a. Party Positions

489. Consistent with Phase II of the 2021 ERP/CEP, for modeling purposes the Company assumes that natural gas fired units will have a book life of 25 years. In general, the Company's Phase II modeling also requires the model to reach 100% clean energy by 2050, which assumes new gas assets will convert to hydrogen or cease operating.[427] Public Service explains that it allows the EnCompass model to build electrolyzers to produce hydrogen, store hydrogen, and build the generation and transmission required to power the electrolyzers. The model can then burn the hydrogen it produces in the thermal fleet.[428] The Company does not, however, include inputs or assumptions for hydrogen transportation. Public Service argues the need for hydrogen pipelines is outside the scope of generation planning (noting that transportation might be negligible if electrolyzers are located adjacent to thermal units). The Company further asserts estimates for hydrogen transportation costs would be too vague and would not add value to the modeling process.[429]

490. The Company encourages all thermal generation resource (*e.g.*, natural gas-fired) proposals to provide for the resource to be capable of burning, at a minimum, 30 percent hydrogen (by volume), while meeting emission permit requirements. Bidders should provide the maximum

[427] Hr. Ex. 1300, Att. CV-9.
[428] Hr. Ex. 102, Landrum Direct, Rev. 1, p. 81
[429] Hr. Ex. 102, Landrum Direct, Rev. 1, p. 82.

percent of hydrogen (by volume) the generator is capable of consuming while meeting emission permit requirements.

491. CEO argues that all gas-only bids in Phase II should have a useful life of no later than 2050 and for the unit depreciation timelines to reflect that retirement date. CEO asserts Public Service misinterprets the USA from the 2021 ERP/CEP when the Company argues that limiting depreciation of gas units to 2050 would shorten the time period allowed by the USA. CEO argues it is illogical to assume that all of the modeling inputs in the 2021 ERP/CEP set forth in the USA will apply equally to the JTS. Further, CEO asserts there is good cause to update the modeling assumptions because the intent was for the 25-year depreciation timeframe to align with a 2050 target, consistent with State policy goals for zero emissions by 2050.[430]

492. CEO similarly argues Public Service should be required to model the extension of existing gas units so long as they do not need to be retired due to the Colorado State Implementation Plan and to provide an analysis on which existing units with PPAs have contracts that can be extended, for how long those contracts could be extended, and whether the unit was bid into Phase II.[431] In addition, CEO recommends the Company model an annual firm gas supply cost escalator sensitivity for each resource portfolio that it develops in Phase II.[432]

493. CEO also puts forth several recommendations regarding the modeling assumptions surrounding hydrogen. CEO asks the Commission to direct Public Service to require hydrogen capable-bids and bids that will rely on carbon capture to specify information such as the year by which the unit will convert to 100 percent hydrogen, the estimated cost for completing that hydrogen conversion; the estimated cost for adding 100 percent carbon capture capability, whether

[430] CEO's SOP at p. 24.
[431] Hr. Ex. 402, Hay Cross-Answer, pp. 23-24; CEO's SOP at p. 26.
[432] Hr. Ex. 401, Ottesen Answer, p. 15.

hydrogen production would occur onsite, the estimated cost of onsite hydrogen production, and the estimated cost to procure hydrogen from another site, including infrastructure such as distribution networks or transportation.[433]

494. Regarding its hydrogen recommendations, CEO argues the Company failed to adequately address in Rebuttal or at hearing recommendations to require developers of hydrogen-capable bids to specify the estimated costs for completing hydrogen conversion, onsite hydrogen production or the cost of hydrogen infrastructure. CEO acknowledges the Company's argument that future electrolyzers may likely be located near hydrogen capable units to minimize transportation costs. CEO argues, however, that because there is no requirement for hydrogen electrolyzers to be located near hydrogen capable units in this Proceeding, assuming zero costs for hydrogen transportation is overly optimistic and could lead to the selection of bids that may ultimately prove to be more expensive than estimated. CEO makes similar arguments regarding the Company's position not to include conversion costs.[434]

495. Like CEO, WRA and SWEEP argue the depreciation lives of new gas units should be limited to 2050. Rather than rely on the assumption that plants will be able to convert to zero-emissions options, WRA and SWEEP argue the most conservative option is to assume that new gas units retire by 2050. WRA and SWEEP further assert the capacity factor of new gas units should be limited to 40 percent, consistent with current EPA power plant rules. In addition, they request that Public Service be required to model short-term life extensions to existing gas units, reasoning that extending current PPAs reduces risks of stranded assets.[435]

[433] Hr. Ex. 401, Ottesen Answer, p. 15.
[434] CEO's SOP at pp. 24-26.
[435] WRA and SWEEP's SOP at pp. 26-28.

496. To ensure that the Company is accounting for the full costs of hydrogen resources, WRA and SWEEP argue the Commission should direct the Company to include hydrogen transport and conversion costs in Phase II modeling, at a level of at least $1 per kilogram.[436]

497. Conservation Coalition similarly recommends that the Phase II modeling be required to fully depreciate the costs of each new gas bid by no later than 2050, except where a bid contains both a plan for the gas resource to be zero-emitting by 2050 and the costs of such plan are included in the modeled cost for the resources. Conservation Coalition adds that this requirement would be for Phase II modeling only; the depreciable life for ratemaking purposes would then be set in the next rate case or in a CPCN, as applicable.[437]

498. Mirroring CEO, CC4CA argues that new gas resources should have a useful life constrain of 2050.[438] CC4CA also asks the Commission to direct Public Service to present an analysis on which existing gas units with PPAs have contracts that expire during the RAP and whether they can be extended, the costs and feasibility of any upgrades that are needed to extend the lives of Company-owned units, and any existing units that are unable to be extended.[439] Finally, CC4CA asks that Public Service include information regarding projected PM2.5 emissions for each of the portfolios it presents in the 120-Day Report so that the Commission can consider any anticipated PM2.5 emission reductions and related benefits, as contemplated by SB 19-236.

499. Onward takes issue with recommendations from WRA and SWEEP to impose artificial modeling constraints on term extensions. Onward asserts that applying any sort of 10-year (or similar) limit to bids for existing gas-fired projects operating under PPAs would be

[436] WRA and SWEEP's SOP at pp. 27-28.
[437] Conservation Coalition's SOP at p. 26.
[438] CC4CA's SOP at p. 5.
[439] CC4CA's SOP at p. 7.

short-sighted and could lead to unintended consequences. For example, Onward warns that artificially constraining the term length of new PPAs would likely lead to less cost-effective bids, which could in turn make bids for new gas-fired resources look more attractive.[440]

500. In Rebuttal, Public Service opposes the recommendations to limit depreciation to 2050, arguing that it is premature to assume that the assets are unable to be useful beyond 2050. Regarding the proposed capacity factor constraint, the Company asserts that adding such constraints can significantly contribute to longer model run times, and the Company's preferred approach is to start without constraints and then go back and add and remodel with them added later only if necessary, such as seeing the capacity factors actually be above the EPA limits.

501. The Company also opposes the various recommendations regarding hydrogen assumptions in Phase II. Public Service argues that, consistent with the 2021 EPR/CEP, bidders should be required to provide as much information as possible about clean-fuels combustion capability in their bids. The Company asserts, however, that future conversion and supply estimates provided by hydrogen-capable bids must be treated as informational only. The Company opposes requiring bidders to provide such estimates in order to bid. On the other hand, Public Service confirms that any bid proposing to combust hydrogen at COD within the RAP or produce hydrogen within the RAP should clearly outline assumptions and costs related to hydrogen production and transportation. [441]

502. Regarding the extension of existing gas-powered units, the Company argues that after accounting for Cherokee 4, which cannot be extended beyond 2028, and those units that are dependent on 2021 ERP/CEP resources, there is such a small amount of potential capacity that the

[440] Onward's SOP at p. 7.
[441] Hr. Ex. 118, Landrum Rebuttal, p. 77.

impact of an extension would likely be minimal. Additionally, Public Service asserts that a directive to force gas units to re-bid is completely inappropriate without detailed testimony regarding the feasibility and costs of such extensions.[442]

b. Findings and Conclusions

503. Starting with the assumed life of new gas plants, we direct that the Phase II modeling assume that new gas-fired units will have a maximum book life of 22 years. This is shorter than the period proposed by Public Service and reflects the legitimate concerns of intervenors such as CEO, Conservation Coalition, CC4CA, and WRA and SWEEP that gas plants will become stranded assets after 2050 given the state's zero emissions goal. At the same time, we decline to adopt a cutoff of 2050 as these intervenors request. With a 2050 cutoff, a thermal unit acquired in 2030 will appear less expensive in the Phase II modeling than the same thermal unit acquired in 2032. This might unintentionally result in the model selecting more thermal generation earlier in the RAP.

504. Any gas plants the model retains after this 22-year period must assume the generic hydrogen conversion costs set forth in Section 2.11 of the Company's Volume 2 (technical appendix).[443] This modeling restriction shall not apply to gas units within the business as usual portfolio. This portfolio does not include the 100 percent by 2050 emissions constraint. To be clear, the 22-year modeling constraint is only for purposes of Phase II modeling. It would be inappropriate in this ERP proceeding to set the depreciable life of new gas units for ratemaking purposes.

[442] Hr. Ex. 118, Landrum Rebuttal, p. 75.
[443] Hr. Ex. 102, Landrum Direct, Rev. 1, pp. 80-83.

505. Regarding hydrogen conversion costs, we share concerns of CEO and WRA and SWEEP that the Company's current assumptions may not fully capture the full costs of converting the Company's gas fleet so that it can burn 100 percent hydrogen. Nevertheless, we agree with Public Service's position that developers should not be mandated to include hydrogen conversion costs for any gas project bid into the JTS. Requiring developers to estimate how much it would cost to convert a gas CT to burn 100 percent hydrogen in 2050 could discourage PPA gas bids and result in widely varying and unreliable estimates. Consistent with the Company's position, estimates provided by hydrogen-capable bids should be treated as informational only, and bidders should not be required to provide estimates in order to bid. On the other hand, any bid that is proposing to combust hydrogen at COD within the RAP or produce hydrogen within the RAP must clearly outline assumptions and costs related to hydrogen production and transportation.

506. While we adopt the Company's proposal regarding hydrogen conversion assumptions, we are unconvinced these assumptions capture the full costs of converting the Company's gas fleet to 100 percent hydrogen. The Commission continues to see considerable risk that new-build Company-owned gas facilities may become stranded as the state transitions to a zero emissions system. This risk underlies our other determinations regarding Company-owned gas units, including our directive that Public Service model a Phase II portfolio that contains no Company-owned new-build gas units.

507. Consistent with requests from CEO and CC4CA, Public Service shall present an analysis in the 120-Day Report that evaluates (1) which existing PPA gas units have contracts that expire during the RAP and whether they can be extended and for how long; (2) the costs and feasibility of any upgrades that are needed to extend the lives of Company-owned units; and (3) information about any existing units, whether IPP or Company-owned, that are not able to be

extended. This requirement is appropriate in light of the Company's failure to include a discussion of the Plains End PPA extension in Phase II of the 2021 ERP/CEP and is similar to the Company's commitment in the 2021 ERP/CEP USA to rebid any existing gas units that are scheduled for retirement in the RAP so long as the retirement is not required pursuant to the Colorado State Implementation Plan and the unit can reasonably be expected to perform in a manner that balances the Company's system. We acknowledge, however, the Company's point that the amount of capacity that could potentially be extended appears to be small.

508. We reject various recommendations that the Company should be required to model the extension of existing gas units. There could be instances in which a PPA does not submit a bid to extend a gas unit or the Company is unable to extend the life of an existing Company-owned gas unit.

509. We reject WRA and SWEEP's recommendation to limit the capacity factor of new gas units to 40 percent, consistent with current EPA power plant rules. Such a constraint may have unintended consequences in the modeling, such as acquiring more gas units that are used less frequently. Further, there is a significant concern that current EPA power plant rules may change. We further reject CC4CA's request that Public Service include information regarding projected PM2.5 emissions for each of the portfolios in the 120-Day Report. The general knowledge that gas plants emit pollutants, including particulates, is uncontested and will be considered by the Commission in our Phase II evaluation, but a detailed analysis of the impacts of specific types of pollutants is better left to the Colorado Air Quality Control Commission when it evaluates the required air permits.

510. We grant CEO's request to require the Company to model an annual firm gas supply cost escalator. Rather than requiring this sensitivity for each resource portfolio, however,

the Company only needs to model the sensitivity on its preferred portfolio. This limitation should again limit Phase II modeling burdens and help eliminate delays. In its Supplemental Direct, Public Service explains that the current firm gas cost assumption for a generic CT is $21.14/kW-yr, remaining flat throughout the analysis. For the sensitivity, the Company shall use an escalator at the generic inflation rate of 2.5 percent instead of keeping the firm gas cost constant, consistent with the Company's proposal in Supplemental Direct.[444]

511. We find this additional sensitivity modeling starts to address our concern that, given the State's goal of reducing local gas distribution utility emissions from the distribution and end-use of gas, retail sales of natural gas may decline going forward. This could result in large firm customers like gas-fired plants bearing a higher percentage of system costs. The higher cost associated with maintaining gas infrastructure that fewer customers need is not represented in the modeling. The firm gas supply cost escalator sensitivity we establish through this Decision starts to address this issue, but we encourage parties in the 2028 ERP to evaluate and propose more robust methods for recognizing this risk.

512. Relatedly, we are concerned the bid prices for new gas-fired facilities fail to include the costs of the gas infrastructure necessary to supply the new facilities. Required upgrades to the natural gas system are real costs of new gas-fired facilities. Accordingly, Public Service shall evaluate whether bids for new gas-fired facilities will require upgrades to the natural gas system over the planning horizon for that utility. We likewise encourage parties in the 2028 ERP to evaluate and propose more robust methods for including the costs of any necessary upgrades to the natural gas system.

[444] Hr. Ex. 111, Landrum Supplemental, p. 38.

4. Generic Prices

a. Party Positions

513. In Rebuttal, Public Service raises the concern that the generic prices proposed in Phase I are significantly below current market expectations and current activities in Congress present significant risk in future project pricing, especially around tax credit opportunities. Based on current ongoing RFP prices in other Xcel Energy jurisdictions, the cost pressures seen in Proceeding 21A-0141E, and the Company's current experience with 2021 ERP/CEP projects, Public Service argues the Phase I generics are significantly below market prices, in some cases maybe as much as half the reasonable expectation for JTS bid prices. The Company recommends using the revised generic prices for Phase II it included in its Rebuttal. [445]

514. The Company also proposes a mechanism in Phase II to automatically adjust generic pricing based on the actual pricing of the bids. If the median bid pricing analysis presented to the Commission in the 30-day Report is more than 20 percent higher or lower than the generic pricing for a given technology, the Company recommends adjusting the generics to have the 2030 generic price, by technology, match the median bid price and then escalate into the future using the price escalation curve of these new generics. The Company would then re-run the locked tails with the updated pricing.[446]

515. Staff opposes the Company's proposal to update generic pricing. Staff asserts the proposed method is not transparent, verifiable, or an appropriate basis for price updates that would apply in the post-RAP period. Instead of the Company's proposal, Staff argues the Commission should order the Company to use public and verifiable sources such as the Lazard Levelized Cost

[445] Hr. Ex. 118, Landrum Rebuttal, p. 69.
[446] Hr. Ex. 118, Landrum Rebuttal, p. 69.

of Energy Study or the National Renewable Energy Laboratory Annual Technology Baseline for its generic pricing assumptions. Staff reasons these types of public sources are driven by long-term trends and are less impacted by year-over-year volatility.[447]

516. Staff also requests the Company be required to confer with Staff and the IE to discuss the appropriate update for all generic pricing prior to the Phase II modeling. Staff notes this would be similar to the process that the Company followed in the last ERP.

b. Findings and Conclusions

517. We approve the Company's proposed mechanism to automatically adjust generic pricing based on the actual pricing of the bids. While we agree with Staff that using public and verifiable sources such as the Lazard Levelized Cost of Energy Study is generally preferable, such sources may not capture the recent impacts to pricing caused by federal legislative changes and tariff uncertainty. Given the dynamic, uncertain environment, we are concerned that looking at the long-term trends presented by public sources could underplay or ignore recent developments.

518. While we disagree with Staff's primary recommendation, we grant its second request and direct Public Service to confer with Staff and the IE to discuss the appropriate update for all generic pricing prior to the Phase II modeling. To be clear, while we welcome Staff's conferral and observation, we adopt the Company's proposed mechanism to base generic pricing on the bids received in the RFP.

5. Modeled Production Costs for Existing Resources

519. In its Answer, Staff notes that Public Service's cost assumptions for its resources may form the basis for future performance evaluation and thus the Company should be required conduct resource planning with reasonably accurate cost projections. Staff put forth analysis,

[447] Staff's SOP at pp. 16-17.

however, showing that the Company's cost assumptions for many existing resources raise many questions. Staff recommended that Public Service explain in Rebuttal the discrepancies observed between modeled future production costs and past reported costs for certain generation resources. Staff warned that if Public Service's Rebuttal leaves cost deviations inadequately explained, the Commission should consider ordering an independent investigation and audit of the Company's processes for developing cost assumptions for resource planning.[448]

520. In its SOP, Staff notes the Company provided no additional information in Rebuttal to explain the significant discrepancies Staff identified between the modeled production costs for existing resources and the costs reported in historical filings with this Commission and the Federal Energy Regulatory Commission.

521. Accordingly, Staff asks the Commission to order an independent review of the Company's processes for developing modeling cost assumptions for existing resources. As an alternative to an immediate investigation, Staff suggests the Commission could require the Company to file a benchmark comparison of its existing resources' historic and future modeled costs in future Phase I ERP filings, similar to the benchmarking analysis provided in Staff's answer testimony. Staff argues the Commission should also require the Company, as part of future ERP proceedings, to identify and explain any material discrepancies between historic and future modeled costs to enable the Commission and parties to review and question the reasonableness of modeled cost assumptions.[449]

522. We agree with Staff and order an independent review of the Company's processes for developing modeling cost assumptions for existing resources. The performance assumptions

[448] Hr. Ex. 2600, Dahlke Answer, p. 78.
[449] Staff's SOP at pp. 36-37.

for Company-owned facilities can have far-reaching impacts, and Staff's assertions that there are significant discrepancies between the current assumptions and those that the Company reported elsewhere are troubling.

523. To initiate this independent review, we direct Staff and Public Service to confer and file a notice in this Proceeding no later than December 31, 2025, detailing the results of the conferral. This should include whether the independent review will take place via an M-docket, I-docket, standalone application, or some other procedural path.

P. Miscellaneous Resource Acquisitions Issues

1. Short List and Best-and-Final Offer

a. Party Positions

524. CIEA urges the Commission adopt a best-and-final-offer ("BAFO") process in Phase II that would allow a subset of bids to refresh their prices. More specifically, CIEA argues that the size of the solicitations, the inflationary environment, and the delays witnessed in the 2021 ERP/CEP justify a new approach in which the bids in the approved portfolio plus the incremental need pool bids (the short list) are allowed a 10 percent price refresh opportunity after the Phase II decision (the BAFO). Public Service would re-rank the projects based on the updated pricing, which CIEA argues would retain competitive tension and increase the chances that the final portfolio would succeed. The Company would then provide a Notice of Final Portfolio and offer the remaining Short List bids the option to join the incremental need pool.

525. To justify the need for the new process, CIEA notes the Phase II process in the 2021 ERP/CEP took 13 months. CIEA asserts that bids that are submitted in Q1 2026 for the JTS RFP have at least the same, if not an increased risk, as in the 2021 ERP/CEP of holding their price for more than a year from the Phase II process. CIEA argues that the BAFO should be adopted given

that the uncertainties in the generation and transmission market globally will make holding prices from Q1 2026 into Q2 2027 difficult if not impossible for both utility and IPP bidders. CIEA asserts other Western utilities have implemented a Short List/BAFO process, so this is not a novel concept.[450]

526. CIEA draws a comparison to the incremental need pool process in which the pool of backup bids are allowed a limited price refresh. CIEA asserts it is illogical that backup bids in the incremental need pool are allowed to reprice but the initial winning bids do not.

527. Interwest also supports the BAFO concept. Similar to CIEA, Interwest asserts cost drivers for all types of generation are rapidly changing. Given the uncertain economic and federal landscape, Interwest argues it is unreasonable to expect a bidder to hold a bid price for any extended period without a BAFO pricing refresh.[451]

b. Findings and Conclusions

528. We reject the BAFO proposal for purposes of this JTS. It is unclear whether there would be sufficient competitive tension during the "final offer" price refresh to prevent gaming. If bidders knew that they would have a 10 percent price increase opportunity after being selected, this might encourage unreasonably low prices in the initial bid. In addition, it is far from certain that the unexpected cost increases and delays that occurred in the 2021 ERP/CEP will repeat in the JTS. While cost pressures have increased since the 2021 ERP/CEP, bidders may be less surprised by such cost pressures and might better be able to accurately incorporate them into their bid prices. Our decisions to adopt a modified version of Staff's tariff passthrough mechanism and incorporate change in law language into the PPAs will help address future uncertainty.

[450] CIEA's SOP at pp. 31-32.
[451] Interwest's SOP at pp. 6-7.

529. Moreover, the modified Phase II Framework and its incremental need pool concept that we adopt already allows a limited price refresh for backup bids. This is directionally consistent with CIEA's BAFO proposal and is a good next step in evolving Colorado's ERP process. Despite CIEA's arguments, it is appropriate for winning bidders to be ineligible for the price refresh opportunity that incremental need pool bids have. Unlike incremental need pool bids, which must wait for a project failure or a material increase in load, winning bids have the opportunity to sign PPAs and begin development shortly after the Phase II Decision.

530. In addition, the BAFO process may not alleviate the risk of delays and project failures. Although the Phase II Decision in the 2021 ERP/CEP took longer than anticipated, the delays experienced in the PPA negotiations were also problematic. CIEA's BAFO proposal ignores this issue. Simply put, even after the price refresh, re-ranking process, and notice of final portfolio, there is no guarantee that the selected projects would be able to quickly sign PPAs and move forward with project development. Thus, the risk of delays and project failures persists.

531. Nevertheless, the Commission is intrigued about the BAFO concept and direct Public Service to confer with CIEA prior to the 2028 ERP about a modified BAFO approach. Specifically, the conferral should examine whether PPA execution could be a component of the BAFO process (*e.g.*, only those projects that execute a contingent PPA would be eligible for the price refresh opportunity). Public Service shall address this concept as part of its direct case in the 2028 ERP.

2. Bid Fees

a. Party Positions

532. Public Service does not propose increasing the bid fees from what was required in the 2021 ERP/CEP but recommends removing most of the options for bidding multiple variations

of a project under a single bid fee. The Company asserts this will help reduce the administrative burden of managing the complexity of multiple options.[452] The Company has maintained two single bid fee options related to backup fuel and the prospective MVLE transmission line segment of the Colorado Power Pathway.[453] In addition, any bid selected to begin PPA negotiation is also required to pay a Second Bid Fee of $1/kW (*e.g.*, 100 MW Project * $1/kW = $100,000) to the Company prior to commencement of negotiations. Upon execution of a PPA the Second Bid Fee is refunded to the bidder. Under the Company's proposal, however, if the bidder and the Company fail to execute a PPA due in part to the bidder's actions that do not reflect bidder's representations or commitments during the RFP bidding process, the Company can retain the Second Bid Fee.[454]

533. Interwest argues that bid fees should not be required for the following variations: (1) CODs, (2) capacity sizes, (3) commercial structures, or (4) tenors (*i.e.*, allow variation of the PPA term and COD; and allow capacity size variations that do not require varying specifications for the collection substation, generator tie-line, or any other generator interconnection information). [455] Interwest characterizes the Company's proposal as "overly aggressive" and argues that it will lead to fewer bids and higher costs. Interwest argues that bidders are not in a good position to evaluate the benefits of variations for the Company and are left to utilize imprecise analysis to select what they think Public Service will find to be the most attractive and cost effective options.[456]

534. Interwest also opposes the Company's plan to impose a second bid fee to negotiate with the utility, which is refundable if PPA is executed. Interwest argues bidders should not be

[452] Hr. Ex. 102, Landrum Direct, pp. 55.
[453] Hr. Ex. 111, Landrum Supplemental, pp. 17-18; Hr. Ex. 101, Att. JWI-2 Vol. 2, Rev. 2, p. 214.
[454] Hr. Ex. 101, Att. JWI-2 Vol. 2, Rev. 2, p. 214.
[455] Hr. Ex. 501, Wilson Answer, p. 7.
[456] Interwest's SOP at p. 6.

required to pay this second bid fee.[457] Interwest asserts there is nothing in the record to indicate that these bid fees after selection are designed to cover RFP administrative costs or have any other legitimate basis. [458]

535. Conversely, CIEA seems to agree with Public Service that the large number of bid variations (especially compared to the actual number of projects) contributed to the modeling issues and delays in the 2021 ERP/CEP. CIEA reasons that limiting bid variations makes sense based on what Public Service can reasonably model. CIEA recommends that bid variations allowed under the same bid fee be limited to variations of the project connecting to the MVLE (if a CPCN is filed in time) and a Company-owned option in addition to a PPA bid. CIEA recommends establishing a per project bid limit of 10, and prohibiting variations for free curtailment, energy-only hybrid PPA pricing, and levelized versus fixed cost pricing.[459]

536. In Pivot's SOP, it recommends the Commission should (1) direct the Company to eliminate its proposed second bid fee; and (2) direct Public Service to charge a bid fee of $750 for projects sized between 100 kW and 2 MW.[460]

b. Findings and Conclusions

537. We adopt the bid fees put forth by Public Service,[461] including the second refundable bid fee for projects that begin PPA negotiations. Public Service has raised legitimate

[457] Hr. Ex. 500, Sanger Answer, p. 15-16.
[458] Interwest's SOP at p. 6.
[459] Hr. Ex. 700, Monsen Answer, Rev. 3, pp. 13; CIEA's SOP at p. 10.
[460] Pivot's SOP at p. 18.
[461] On September 24, 2025, Public Service, Staff, CEO, and UCA ("Joint Movants") made a filing in Proceeding No. 21A-0141E that pertains to the bid fees required in the JTS base RFP. In that filing, the Joint Movants propose discounting the JTS bid fees for certain bids that were also submitted into the Near-Term Procurement ("NTP") RFP process in Proceeding No. 21A-0141E. Specifically, for developers with bids in the NTP that are not ultimately selected as part of the NTP, and who then submit bids into the JTS Base RFP, the $2,000 NTP bid evaluation fee for each non-selected NTP bid will be treated as a credit and allowed to offset the associated JTS bid evaluation fees. Our decisions in this JTS Proceeding regarding bid fees in no way alter the Joint Movants' proposal to discount JTS bids that were also bid into the NTP.

concerns, echoed by CIEA, that evaluating numerous variations of the same projects increases complexity and the risk of delays in the Phase II modeling. Other than variations regarding the MVLE and backup fuel for thermal bids, developers shall be required to put forward their best bid or pay a second bid fee. The Commission likewise supports the Company's second bid fee for projects that begin PPA negotiation. This second fee both reflects the additional resources the Company expends negotiating PPAs and hopefully further incentivizes developers to quickly come to an agreement.

538. There is insufficient record to determine that the level of bid fees, including for small projects, is too high, especially because the Company has not increased the fees since the 2021 ERP/CEP.

3. RFP Requirements

a. Party Positions

539. Interwest recommends several specific changes to the RFP, which sets forth the rules with which bidders must comply to have their bid evaluated. Interwest first opposes the RFP's prohibition on out of state company ownership bids. Interwest argues that the most cost-effective bids should win, regardless of where they are located. Interest's second challenge is to the 15-year maximum term for hybrid PPA projects, such as solar plus storage resources. Interwest argues that the term-limit on hybrid projects should match 25-year limit on other PPAs or should at least match the 18-year limit from the 2021 ERP/CEP's RFP. Interwest's third objection concerns the RFP's exclusivity requirement. Interwest argues that developers should be able to bid the same project into multiple RFPs or otherwise sell a project that has been bid. In addition, Interwest notes that, based on discovery, Public Service plans to set the due date for Company-owned bids one day

before PPA bids. Interwest supports this plan and states it is important that Company-owned bids not be allowed to come in after PPA bids.[462]

540. Finally, Interwest argues that the non-price scoring analysis in the RFP is vague and subjective. Interwest recommends the Company develop a detailed non-price scoring matrix in this RFP so that bidders are able to self-score and design their bids according to what the Company expects. CIEA similarly offers a recommendation regarding the non-price factor analysis. CIEA argues the bidder qualifications should be prioritized over other non-price factors to increase viability of bids.[463]

b. Findings and Conclusions

541. We grant Interwest's first request regarding out-of-state Company ownership bids and direct the Company to remove this prohibition from the RFP. We find persuasive Interwest's arguments that the most cost-effective bids should win. At the same time, however, we reiterate that the Company retains discretion with its development and submission of Company-owned bids.

542. We also grant Interwest's second request to remove the 15-year maximum term for hybrid projects. In the 2021 ERP/CEP, there was considerable adjudication over the treatment of hybrid resources such as solar plus storage. Public Service raised concerns that, without certain restrictions, hybrid resources could be viewed as finance leases. IPP interests raised concerns about the lack of capacity payments and unnecessarily short-term limits. In the Phase I RRR Decision, the Commission found that allowing hybrid projects to receive capacity payments but limiting the term length of the storage component to 18 years "strikes an appropriate balance between addressing the finance lease concern and allowing IPP solar plus storage bids to be more

[462] Hr. Ex. 500, Sanger Answer, pp. 8-14.
[463] CIEA's SOP at p. 10.

competitive."[464] We are unclear why Public Service shortened the term length for hybrid projects to 15 years in this JTS Proceeding.[465] Regardless, we adopt the approach from the 2021 ERP/CEP and allow hybrid projects to receive capacity payments but limit the term length of the storage component to 18 years.

543. We reject Interwest's third proposed modification to the exclusivity requirement. The Company, parties, and the Commission should not spend time evaluating bids that are not fully committed. Allowing bids to leave the solicitation process if they receive a better offer in a separate solicitation could increase the difficulty of bid evaluation and selection. In addition, the exclusivity requirement to which Interwest objects was also present in the 2021 ERP/CEP.[466] This requirement did not seem to unduly restrict bidders in the 2021 ERP/CEP.

544. As for the Company's plan to set the due date for Company-owned bids one day before PPA bids, we agree with Interwest about the importance of this deadline. Instead of letting this simply be the plan for the deadline, we clarify that all Company-owned bids shall be submitted one day prior to the deadline for PPA bids.

545. Regarding the non-price scoring analysis, consistent with Interwest's recommendation, Public Service shall develop and make available to bidders a detailed non-price scoring matrix in this RFP so that bidders are able to self-score and design their bids according to what the Company expects. Given that the Company already has (or is at least developing) some way to apply the non-price scoring to bids, it is reasonable to provide this plan to bidders beforehand. Providing this scoring matrix to bidders significantly increases transparency. Moreover, to further increase transparency, Public Service shall notify Staff any time a bid fails

[464] Decision No. C22-0559 at ¶ 44 issued in the 2021 ERP/CEP (Sept. 21, 2022).
[465] *See* Hr. Ex. 101, Att. JWI-3, Vol. 3, Rev. 1, p. 16.
[466] Hr. Ex. 101, Att. AKJ-3.2-1, p. 18 in the 2021 ERP/CEP.

the non-price factor analysis. The notification to Staff must include a detailed description of why the bid should not be advanced to computer-based modeling. Staff can raise any concerns it has with the Commission, at its discretion. We reject CIEA's related request to prioritize bidder qualifications. We are unconvinced that such an approach is an appropriate way to increase the viability of bids in the approved portfolio.

546. Going forward, in the 2028 ERP, Public Service shall present its proposed non-price scoring matrix as part of its direct case for parties to evaluate during the course of the proceeding. As part of this non-price scoring matrix, the Company shall propose as an additional consideration of whether a developer has backed out of an approved bid in the JTS. If a bid is selected as part of the JTS bid evaluation and selection process but the developer subsequently withdraws the bid, the developer's bids may be viewed less favorably in the 2028 ERP.

4. Solar Regulating Reserve Penalty

a. Party Positions

547. In its Direct, the Company proposed a Solar Regulating Reserve ("SRR") penalty of $8/kW-year for solar projects located within a 37-mile radius of Pueblo to account for increased regulation costs associated with high ramp rates of the concentration of solar facilities in the area. Solar bids proposing to locate in the area would also be ineligible for the just transition modeling credits. To conduct its SRR analysis, the Company developed a regression model using five-minute 2022 plane-of-array ("POA") irradiance at the Neptune solar plant outside of Pueblo to predict the plant's measured 2022 AC generation. It then used this model to convert irradiance data at other locations to generation estimates for not-yet-built solar generators by scaling the resulting generation to match the AC installed capacity of the new solar generators.

548. The Company used this method to develop generation profiles for two 1-GW solar portfolios. One portfolio was composed of four bids from the 2021 ERP located in the Pueblo area; the other portfolio was composed of two existing and two fictional solar plants located in the Craig and Keenesburg areas. Where the Company did not have POA irradiance data (from existing plants) it used location-specific solar data obtained from NREL. Using the Neptune regression model and the local solar data, the Company generated five-minute generation estimates for each of the unbuilt solar plants, which, together with the measured data from the operational plants, were aggregated into annual Pueblo-area and non-Pueblo-area one GW generation profiles with five -minute resolution. These profiles were then added to the 2028 net load profile. The Company then used these data sets to identify the largest 15-minute up and down ramp rates throughout the year. From this, the Company determined that an incremental one GW of solar in the Pueblo area would require 691 GWh of regulation reserve more than an incremental one GW of solar located in areas distant from Pueblo. Finally, the Company applied the average of regulating reserve costs per MWh from MISO, SPP and CAISO to the 691 GWh difference, and calculated that the additional regulating reserve cost for solar in the Pueblo area amounted to $7.68/kW-year, which it proposes to round up to the $8/kW-year penalty for Pueblo-area solar.[467]

549. In its Answer, CEI alleges a fundamental flaw in the Company's analysis that resulted in the proposed value of the penalty.[468] In Rebuttal, the Company agrees with CEI and proposes a revised penalty of $2.59/kW-year based on the CEI corrections. However, the Company contests all other arguments posed by CEI and other parties. Among these were that the SRR penalty is unnecessary because even relatively minor geographic distances between solar resources

[467] Hr. Ex. 102, Att. JTL-2.
[468] Hr. Ex. 2200, Lucas Answer, pp. 36-46.

create substantial diversity in the timing of ramps due to passing clouds;[469] that the Company failed to make a parallel analysis of wind ramp rates;[470] that there are no incremental regulation costs because the Company already owns or will own sufficient regulating capacity;[471] that solar + storage resources can inherently limit their ramp rates and so should not be subject to the penalty and remain eligible for the Just Transition credit; and that the Company's use of regulation costs from three ISOs to estimate its incremental regulation costs was improper or inaccurately applied.[472]

550. Interwest notes the Company's agreement during the hearing that both storage and gas facilities provide regulating reserves, and that these resources are likely to be added to the system in and around Pueblo. Interwest contends that as a result, the system around Pueblo may be materially different after a Phase II portfolio is approved, so excluding solar from the just transition modeling credits and applying the SRR penalty are unwarranted. Instead, Interwest recommends the Commission require the Company to select resources in and around Pueblo that achieve the necessary reliability and operational requirements when taken in conjunction with each other and the current system. Interwest argues that pre-determining a reasonable quantity of each resource type without knowing what other resources will be added is unreasonable, particularly since some resources in the portfolio could diminish the need for regulating reserves.[473]

551. In addition to citing the flaws described by CEI, EJC contends the SRR Study was flawed in that it ignored how pairing solar with storage could address the ramping needs alleged by the Company. EJC contends further the SRR penalty would discourage construction of clean

[469] Hr. Ex. 2200, Lucas Answer, pp. 46-50.
[470] Hr. Ex. 2200, Lucas Answer, pp. 54-57.
[471] Hr. Ex. 2200, Lucas Answer, pp. 63-64.
[472] Hr. Ex. 2200, Lucas Answer, pp. 57-60.
[473] Interwest's SOP at pp. 11-12.

resources in the Pueblo area, which would be contrary to the Commission's equity obligation to prioritize benefits to DI communities. EJC argues this is particularly troubling given the modeling credits for gas plants to locate in Pueblo. EJC recommends that the Commission reject the SRR penalty and require that solar bids in the Pueblo area be eligible for the just transition modeling credits.[474]

552. In Rebuttal, the Company proposes applying the SRR penalty of $2.59/kW-year to solar bids within 37 miles of Pueblo and excluding such bids from eligibility for the just transition modeling credits.

b. Findings and Conclusions

553. We find the intervenor arguments against the SRR penalty to be valid. It is inaccurate not to incorporate the impact of wind resources when assessing the need for regulating reserves. CEI's criticisms of the way in which the Company estimate the cost of regulating reserves appear well founded. EJC is correct that the Company's proposed penalty has no exemption for combined solar + storage resources that have the inherent capacity to limit ramp rate. The SRR penalty would discourage emission-free generation in an area that has a high concentration of DI communities, while the just transition modeling credits would encourage siting gas-fired generation there. And Interwest's point that it is premature to judge the need for regulating reserves when the approved portfolio may include gas and storage resources in the Pueblo area that can provide this service is also well taken. Additionally, we note CEI's point that even limited geographic diversity of multiple solar resources will attenuate their aggregate ramp rate, as it takes time for clouds to move from one array to another.

[474] EJC's SOP at pp. 11-13.

554. Accordingly, we find the proposed SRR penalty is neither conceptually well-founded nor methodologically accurate and so reject both the SRR penalty and the Company's proposal to exclude solar resources in the Pueblo area from eligibility for the just transition modeling credits.

5. Curtailment of PTC-Qualified Facilities

a. Party Positions

555. In its Direct, Public Service initially proposed to discontinue reimbursing IPPs for lost PTCs due to compensable curtailments. Public Service made the same proposal in the 2021 ERP/CEP, but in the USA the Company ultimately agreed to reverse course and allow for compensable curtailment (*i.e.*, bidders are reimbursed for lost PTCs due to compensable curtailments). Although the Company maintained its Direct position in Rebuttal, Public Service argued in the alternative that if the Commission continues compensation for compensable curtailments the Commission should expressly allow the Company to curtail PTC-qualified facilities on an equal basis, no matter their individual income tax rate and regardless of whether the project is a UOG project or IPP owned. [475]

556. During the hearing, the Company reversed course and offered to continue reimbursing IPPs for lost PTCs due to compensable curtailments. Public Service reiterated its request, however, that the Company be allowed to curtail PTC-qualified facilities on an equal basis, no matter their individual income tax rate.[476]

557. The IPP interests such as CIEA and Interwest agree with the Company's most recent proposal to continue compensating for compensable curtailments. CIEA, however, argues

[475] Hr. Ex. 120, Bornhofen Rebuttal, p. 37.
[476] *See* Hr. Tr. June 17, 2025, pp. 252-55.

the Commission should reject the Company's related request to allow the Company to curtail PTC-qualified facilities on an equal basis, no matter their individual income tax rate. Instead, CIEA argues that the model PPA curtailment language in the 2021 ERP/CEP that was agreed upon in the USA should be maintained.

558. CIEA argues the Company has failed to meet its burden of showing why the PPA should be modified to allow curtailments regardless of individual tax rates. CIEA argues there is "scant" information in the record on this point and characterizes Public Service's proposed modification as "a last-minute change." CIEA states:

> Public Service offered one question and answer to this proposal in its pre-filed testimony. Public Service at hearing could not explain what the tax rate selected would be, and its witness explained that he was not an expert in the tax issues for which he was the sole Company witness discussing.[477]

b. Findings and Conclusions

559. The Commission expressly approves the language in the 2021 ERP/CEP that was agreed upon in the USA regarding compensable curtailments. In addition, the Commission rejects the Company's request to curtail PTC-qualified facilities on an equal basis, no matter their individual income tax rate.[478] The Commission agrees with CIEA that the Company failed to put forth sufficient evidence to justify modifying how the Company currently curtails PTC-eligible projects. Public Service did not make this request is Direct. No parties filed Answer testimony on it. The testimony in Rebuttal and at hearing is sparse and leave many questions unanswered.

560. For instance, the Company has argued that the monetary impact is relatively small per year for an individual project. The Company has not, however, explained how much money

[477] CIEA's SOP at p. 36.

[478] Chair Blank dissents and would grant the Company's request to curtail PTC-qualified facilities on an equal basis.

this change would likely cost ratepayers in the aggregate (*i.e.*, throughout the Company's system and over the entire period in which projects are eligible for PTCs). The Company has also provided little information about why the current approach for curtailments must be changed. The Company references a desire to curtail projects equitably. If certain projects cost more money to curtail than other projects, however, it seems appropriate to reflect this cost difference in the Company's curtailment decisions.

6. Tariff Passthrough

a. Party Positions

561. In its Answer, CIEA argues that a project bidding in 2026 would be "throwing darts at a board" as to tariffs on equipment delivered in 2029 or 2030.[479] CIEA notes it is possible that tariffs in place during the RFP will be lifted when equipment is received in 2029 or 2030, potentially resulting in a windfall for the developer. CIEA recommended the Commission allow limited repricing for all projects or pass-through via the ECA of the actual costs of any tariffs incurred.

562. In Rebuttal, Public Service expresses openness to a modified version of CIEA's proposal. The Company states it is evaluating an approach where bidders provide anticipated supply chain/country of origin(s) for critical components, quantifying these assumptions as part of their bid packages.[480]

563. In Cross Answer, Staff opposes CIEA's specific approach to pass through tariff-based costs but puts forth a modified approach to accomplish the same result. Staff opposes CIEA's approach because removing all tariff risk from bid pricing could result in poor decisions in the face

[479] Hr. Ex. 700, Monsen Answer, Rev. 1, pp. 98-99.
[480] Hr. Ex. 117, Ihle Rebuttal, p. 61; Hr. Ex. 120, Bornhofen Rebuttal, pp. 24-25.

of tariff risks that could be avoided or hedged. For example, Staff argues the model may over select a resource that is highly susceptible to future tariff costs instead of less risky resources.[481]

564. Under Staff's proposed tariff mechanism, bidders would be required to separate bid prices into two components: a base project cost and a current and known tariff estimate ("CKTE"). Bidders would support their CKTE by submitting a sourcing plan. The IE and Public Service would flag any questionable or incomplete CKTEs and sourcing plans in initial screening for potential clarification or disqualification. Selected projects would be required to file updates on CKTE's and sourcing plans if tariff rates change prior to project delivery and completion. In any event, tariff-caused prices increases would be limited to less than 20 percent of overall project costs and projects would be required to provide actual tariff cost documentation for verification through an Independent Auditor process prior to cost remuneration.[482]

565. During the hearing, Public Service admitted Hearing Exhibit 131, which summarizes the main components of Staff's tariff passthrough proposal, states the Company's position on each component, and provides specific comments and suggested modifications. Overall, Public Service states that it supports Staff's tariff passthrough proposal with the Company's modifications as reflected in Hearing Exhibit 131. Public Service characterizes the tariff passthrough mechanism as another important concept to drive the JTS forward and capture the best bids possible while managing substantial uncertainty.[483]

566. In its SOP, Staff states it is supportive of the clarifications and modifications that Public Service makes to the proposal in Hearing Exhibit 131, with two exceptions. First, Staff states it cannot agree to limit the CKTE to an amount that is "reasonable" in comparison to the

[481] Hr. Ex. 2605, Dahlke Cross Answer, p. 12.
[482] Hr. Ex. 2605, Dahlke Cross Answer, p. 30.
[483] Public Service's SOP at pp. 29-30.

overall bid cost. Staff argues the purpose of the CKTE is to get an accurate picture of projected costs based on tariff rates in effect at the time of the bids, regardless of the reasonableness of such rates. Second, Staff agues the term "major equipment" should be more clearly defined to prevent differing interpretations among the Company and bidders. At a minimum, Staff argues "major equipment" must consist of the following: (1) wind: tower, blades, and nacelle assembly; (2) solar PV: panels, inverters, and mounting structures; (3) gas: turbine and generator; and (4) battery: battery modules and power conversion system.[484]

567. Regarding the cap on price increase, Staff sticks with its original proposal for a 20 percent cap on price increases. Rather than terminating a project if it exceeds the 20 percent cap, however, Staff recommends the Commission conduct a notice and review process to reconsider whether to proceed with the project or seek alternative options.[485]

568. CIEA generally supports Staff's passthrough proposal, as modified by Public Service, but suggests additional modifications. For instance, CIEA argues that if tariffs cause prices to rise above the 20 percent price cap, that should trigger a Commission review of the update rather than automatic withdrawal. For any projects that must withdraw due to exceeding the CKTE cap, CIEA argues Public Service should be prohibited from charging a termination payment or loss of security as such costs are out of the developer's control.[486]

569. CEI supports the passthrough concept but argues the information bidders provide to substantiate tariff cost claims and support a CKTE passthrough should be minimized to avoid revealing any pricing information that would give the Company a competitive advantage. CEI recommends the Commission approve the CKTE process in Hearing Exhibit 131, with a

[484] Staff's SOP at p. 20.
[485] Staff's SOP at pp. 20-21.
[486] CIEA's SOP at pp. 33-34.

commitment to further modification in a stakeholder process between the Phase I decision and the Phase II RFP.[487]

570. Climax supports Staff's tariff passthrough, with Public Service's adjustments, and urges the Commission to adopt it.[488]

571. CEC generally supports Staff's tariff passthrough concept, as modified by Public Service in Hearing Exhibit 131. CEC opposes, however, the 20 percent cap as being too high. CEC recommends the Commission should instead approve a more reasonable ceiling for CKTE increases that qualify for automatic pass-throughs such as 5-10 percent of overall project costs.[489]

b. Findings and Conclusions

572. We adopt Staff's tariff passthrough proposal, as modified by Public Service in Hearing Exhibit 131 and further modified by Staff in its SOP. The one deviation we make from the proposal Staff advances is to grant CEC's request and lower the price cap from 20 percent to 10 percent. This lower price cap reduces the risk of bidders attempting to game the passthrough mechanism.

573. Other than the reduced price cap, we note that Staff's tariff passthrough concept has broad party support. However, we reject CIEA's request that bidders be able to walk away from their project if the tariff impact exceeds the price cap. We fear such a mechanism would incentivize bidders to claim a more than 10 percent tariff impact whenever the bidder wanted to leave the PPA.

574. We similarly recommend denying CEI's request for a stakeholder process between the Phase I decision and the Phase II RFP to determine how to ensure that the information bidders

[487] CEI's SOP at p. 26.
[488] Climax's SOP at p. 6.
[489] CEC's SOP at p. 16.

provide does not give Public Service a competitive advantage. First, in Hearing Exhibit 131, Public Service opposes the proposition that it and the IE would flag any questionable or incomplete CKTEs and sourcing plans. Instead, the Company recommends that this be "a completeness review only, by an outside consultant, without focus on substantive content or accuracy of CKTE assumptions."[490] Staff does not challenge this modification in its SOP. Thus, under the modified tariff passthrough, Public Service would not be reviewing the CTKEs and sourcing information that bidders provide. Secondly, we are concerned about the timing impacts of requiring additional process prior to the submission of bids.

7. Demand Response and Aggregated Distributed Energy Resources

a. Party Positions

575. The Company explains that it conducted its resource adequacy study with its existing portfolio of DR programs including the Saver's Switch, SolarRewards, and ISOC programs.[491]

576. With respect to additional distributed energy resources, Public Service modeled 900 MW of ADERs starting in 2028 in a subset of portfolio scenarios.[492] The Company modeled ADERs as a four-hour storage device with essentially unlimited flexibility. However, the Company concluded "our testing resulted in minimal differences in sizing of the portfolios … [which] leave[s] us with the conclusion that while helpful, ADERs will not be enough to get us to our overall emissions reduction objectives and carbon-free goal."[493]

577. WRA and SWEEP argue the cost assumptions of generic advanced technology resources are speculative and the Company's cost assumptions for the ADER generic resource are

[490] Hr. Ex. 131, Public Service's Position on Staff's Tariff Risk Recommendation, p. 1.
[491] Hr. Tr. June 17, 2025, pp. 28-29.
[492] Hr. Ex. 102, Landrum Direct Rev. 1, p. 89.
[493] Hr. Ex. 102, Landrum Direct Rev. 1, p. 105.

overestimated as Public Service can access ADER capacity lower than the full cost of residential or commercial battery storage.[494] They note that Public Service provides an incentive of $350/kW, up to $5,000 per application, plus $100 per year for continued participation in the demand management program. WRA and SWEEP also suggest that the Tesla Powerwall 3 costs around $15,000 for battery plus installation, and determines that the Company can utilize the storage capacity of customer assets at about one third the total installed cost and possibly lower as technology improves.[495]

578. In its SOP, WRA and SWEEP argue the Company should update the cost modeling of generic ADERs in its next Phase I Electric Resource Plan based on the Company's Renewable Battery Connect ("RBC") and virtual power plant ("VPP") tariff options as well as ADER bids received through any administered competitive solicitations, such as the VPP program. WRA and SWEEP also contend the Company should expand generic resource modeling to reflect distributed energy resources beyond battery storage, including consideration of energy efficiency, demand management, and distributed generation, and to represent the opportunity of these resources via an inclining supply curve.

579. CEI argues that the Company conflates the total cost of storage assets for the costs it pays through RBC and other ADER programs. CEI utilized values from a Brattle Group report to determine that ADER programs offer storage capacity at approximately $85/kW-year, a value substantially lower than the Company's assumed value of $475/kW-year.[496] CEI also asserts the Company ignored likely non-system wide benefits of ADERs including distribution system value.

[494] Hr. Ex. 1300, Valentine Answer, p. 84.
[495] Hr. Ex. 1300, Valentine Answer, p. 85.
[496] Hr. Ex. 2201, Turner Answer, p. 12.

They point to a list of studies that indicate the value of avoided distribution investment that range from $60/kW-yr to $87/kW-yr.

580. However, CEI notes that because Public Service is not proposing any action in this Proceeding, the Commission need not take any action in its Phase I order on these issues; instead, it should examine them closely in related proceedings.[497]

581. In Rebuttal, Public Service asserts the reality of many existing DER programs today is that they are deployed for direct participant benefits that would limit the use of the asset from a system operations perspective.[498] Thus, the Company argues it is inappropriate to model utility-only costs with the full range of battery benefits. Public Service argues the Company's modeling approach, including total costs and total benefits, is at least closer to accurate. With respect to the RBC program, the Company explains the terms and conditions of the program only allow it to dispatch up to 60 events per year.[499] These limitations mean the capacity available from RBC is not a like-for-like replacement of larger-scale battery storage resources that do not have these limitations.

b. Findings and Conclusions

582. The Commission recognizes that contractual limitations associated with DR and ADER participation inherently reduce some of the flexibility of those resources (relative to fully-owned or -controlled resources). However, we believe that, with continued improvement in program design and management, DR and ADER resources offer the potential to meaningfully facilitate the Company's ability to meet its peak load obligations, especially considering that many of those contractual limitations are either set by the Company or in adjudications before the

[497] CEI's SOP at p. 27.
[498] Hr. Ex. 125, Pollock Rebuttal, pp. 8-9.
[499] Hr. Ex. 125, Pollock Rebuttal, p. 10.

Commission. We agree with WRA and SWEEP that more should be expected of the Company in its next ERP. Specifically, we require Public Service to update the cost assumptions in its 2028 ERP, informed by: (1) the Company's relevant programming, such as RBC and VPP tariff options, and (2) ADER bids received through any administered competitive solicitations. We also require Public Service to address in its Phase I filings whether generic resource modeling should or should not reflect DERs beyond battery storage, and to provide thorough evaluation of leveraging such resources to serve its system peak requirements as well as reduce the need for transmission and distribution infrastructure.

Q. Miscellaneous Transmission Issues

1. Financing Transmission Projects via the Colorado Electric Transmission Authority ("CETA")

583. WRA and SWEEP assert there is an unprecedented need to expand and upgrade the nation's transmission infrastructure to maintain grid reliability, improve resilience, and meet climate goals. They state that by offering lower costs compared to traditional investor-owned utility financing, public financing for transmission can minimize upward rate pressure. Such a financing pathway could also reduce the risks of sole dependency on private sector banks which often carry higher interest rates for financing. WRA and SWEEP argue that a utility has a fundamental duty to minimize costs. If public financing can demonstrably lower the cost of a necessary transmission project, then a utility has a responsibility to pursue that option. Given the potentially significant rate impacts of traditional transmission financing, they argue, exploring public-private partnerships is a prudent step to mitigate those impacts. Accordingly, they recommend that the Commission require Public Service to partner with CETA to identify and

evaluate which planned or potential transmission projects could be suitable candidates for utilizing CETA's revenue bond financing.[500]

584. The Company states that it and CETA already engage through CCPG, and the Company actively participated in CETA's Transmission Expansion Study. The Company remains interested in working with CETA in the future but asserts CETA is still in policymaking stages for its revenue bonding. As CETA becomes more equipped to provide the services identified in its statutory authority, the Company states it is willing to discuss how those authorities may complement the Company's transmission planning.[501]

585. We agree that CETA financing of transmission projects offers potential ratepayer savings. We therefore direct the Company to engage actively with CETA to either propose CETA financing of all transmission projects needed to support the approved JTS portfolios or provide detailed explanations of why it is not doing so in all relevant future CPCN applications.

2. Evaluation of Dynamic Line Ratings

a. Party Positions

586. Public Service evaluates the applicability of dynamic line ratings ("DLR") in resolving reliability issues identified in its JTS Transmission Study. The Company states that in the base forecast study it reviewed 23 circuits for the ability to apply DLR and in the low forecast study it reviewed eight circuits. The Company asserts that in many cases circuits were not good candidates because, for example, they include underground segments or their capacities are limited by substation elements that would require costly upgrades. The Company argues that applying DLR to the remaining viable candidate circuits alone would be insufficient to resolve all the system

[500] Hr. Ex. 1302, Richardson Answer, pp. 19-20.
[501] Hr. Ex. 121, Martz Rebuttal, p. 71.

violations identified in the JTS Transmission Study. Public Service states that following approval of a portfolio in Phase II, the Company will evaluate transmission overloads on the existing system caused by the portfolio and determine whether any indicated transmission upgrades could be avoided by DLR.[502]

587. UCA notes that in conducting its evaluation of DLR, the Company explicitly excluded the Colorado Power Pathway. UCA contends that this was inappropriate, given that the Colorado Power Pathway will be carrying substantial wind generation, and thus could benefit from increased rating when the lines are cooled by wind. UCA argues that DLR should be applied specifically to Segment 1 of the Colorado Power Pathway from Ft. St. Vrain to Canal Crossing, but that it should not be applied to Segment 5 (from Sandstone to Harvest Mile) because it claims that doing so would trigger the need for the expensive Harvest Mile-Chambers-Sandown-Cherokee upgrade project. UCA also proposes that DLR be evaluated on the Rush Creek gen tie between the Pronghorn and Missile Site substations, which was also built to carry wind generation.[503]

588. The Company disagrees with UCA, stating that the fact that a transmission line is used to interconnect wind generation is not sufficient evidence of meteorological conditions to alone support the deployment of DLR as UCA suggests. The Company also notes that the lines UCA would like DLR installed on are limited to the 3,000-amp breaker capacities in substations. It states that while these breakers could be upgraded, there is substantial incremental cost to upgrading substation elements that more than likely outweighs the incremental benefits of DLR, particularly since FERC Order No. 881 requires that these lines use ambient adjusted ratings (thus reducing the potential incremental benefit of DLR).[504]

[502] Hr. Ex. 111, Martz Supplemental Direct, pp. 32-43.
[503] Hr. Ex. 305, Neil Answer, pp. 58-59.
[504] Hr. Ex. 121, Martz Rebuttal, pp. 73-75.

b. Findings and Conclusions

589. Public Service claims the application of DLR might require breaker upgrades in substations and so could be much more costly than just installing DLR on its lines. However, the Company has not demonstrated that DLR would actually necessitate such breaker upgrades, nor that if required, these upgrades would render DLR non-cost effective. We agree with UCA that these lines were built to carry large volumes of wind power and that it is reasonable to investigate whether DLR could cost-effectively increase volume of wind energy they transport.

590. Therefore, we direct that the small stakeholder group established as part of the Phase II Framework, supported by the ITA, discuss the potential benefits of DLR on the lines recommended by UCA. If the stakeholder group finds that further analysis of DLR is warranted, we direct the Company to model and report on the application of DLR to the lines recommended by UCA as part of the assessment of proactive projects contemplated in the Phase II Framework.

3. Investigation of Interconnection with the PacifiCorp Gateway South Line

a. Party Positions

591. As discussed in Section 2.15 of the Technical Appendix, per the USA from the 2021 ERP/CEP, the Company studied the "Gateway South-Northwest Colorado 500 kV Interconnection Project." This project posits a 500 kV connection between either the Craig or Hayden substation to a substation on Pacificorp's Gateway South line. The Company explains that:

> The study attempted to understand how generation dispatch between Public Service's area in Eastern Colorado and the PACE area in Wyoming impacts the amount of flow possible on these two alternative lines. The results of the analysis showed that power transfers between the PACE area via the conceptual connection are possible, but do not alleviate existing limitations related to the existing transmission paths within Colorado. Further, the

> result of this analysis shows a redistribution of flows between the TOT3 and TOT5 paths, depending on direction of transfer. While the addition of either of these alternatives was found to relieve post-contingent loading level in some areas, other areas saw loadings in excess of their ratings. Additional study is required to assess the costs and capabilities of such a connection compared to the value provided.[505]

592. The Company cautions that interstate transmission is subject to several layers of national, state, and local regulation as well as the potential for stakeholder opposition. It also states that "[e]ven before those challenges are encountered, insufficient intra-state transmission capability stands as the primary hurdle to realizing the value of interstate expansion," but states that it continues to work with state, regional and national partners to understand the potential for interstate transmission.[506]

593. WRA and SWEEP contend that this project would increase the Company's access to other power markets and increase the geographic area (and thus resource diversity) in which it can utilize renewable energy resources. They assert the Company's study of the line was incomplete in that it looked only at reliability impacts, failing to investigate the costs and benefits of the project. WRA and SWEEP refer to a discovery response in which the Company states that it is assessing potential next steps but does not know when additional studies will be conducted. WRA and SWEEP recommend the Commission direct Public Service to conduct detailed studies that fully assess two key aspects of a potential interconnection with Gateway South: first, the potential net benefits, and second, the necessary system upgrades – and associated costs – required to facilitate such an interconnection. WRA and SWEEP envision that this study would quantify environmental, reliability and resilience, and economic benefits for Colorado customers and provide estimates of the cost and timeline for any necessary upgrades to the Company's existing

[505] Hr. Ex. 105, Siebenaler Direct, pp. 87-88.
[506] Hr. Ex. 105, Siebenaler Direct, pp. 87-88.

transmission system. They recommend further that the Commission direct the Company to report its findings within 18 months of the Phase I decision .[507]

594. The Company does not respond to WRA and SWEEP's recommendation.

b. Findings and Conclusions

595. In the 2021 ERP/CEP, the Commission required Public Service to provide supplemental direct testimony reporting on the reserve margin and other potential benefits from a 400 MW increase in the bi-directional transfer capability between Public Service and "Pacificorp East" starting in 2028.[508] In response, the Company conducted a capacity expansion modeling run simulating the expected impacts of an approximately 60-mile long, 500 kV transmission line running from its Hayden substation due west to a new 500 kV switching station on the Pacificorp Gateway South project, where it would interconnect. The Company estimated the cost of this project at $269 million and estimated $700 million in net benefits. Public Service suggested that these results provided a sense of the potential but cautioned that the cost estimate was at a very high level and that the modeled benefits were highly dependent upon the assumed reduction in planning reserve margin that this connection would enable and the assumption of a liquid and organized market on the Pacificorp side of the interconnection.

596. WRA and SWEEP are correct in noting that the study submitted in this Proceeding regarding the transmission link to the Pacificorp Gateway South project focuses exclusively on reliability impacts, providing no insight into other costs or benefits the project might provide. Indeed, the Company states that "[a]dditional study is required to assess the costs and capabilities of such a connection compared to the value provided."[509] While the information provided in the

[507] Hr. Ex. 1302, Richardson Answer, pp. 14-18.
[508] Decision C21-0395-I at ¶ 9 issued in the 2021 ERP/CEP (July 2, 2021).
[509] Hr. Ex. 105, Siebenaler Direct, Rev. 1, p. 89.

2021 ERP/CEP is indicative of the potential benefits of interregional transmission, the analysis underlying that information cannot be considered a rigorous assessment of the likely costs and benefits of such a project.

597. We note that in July 2025, the CETA Board of Directors approved a shortlist of six priority transmission projects, among which was a 38-mile transmission link between the Company's Craig power plant and the same Pacificorp Gateway South line. This indicates that CETA has found there to be considerable benefit to forging a link nearly identical to the one that has been a focus of both this JTS Proceeding and the 2021 ERP/CEP. In sum, the Company's own analysis indicates this transmission link could be highly beneficial for ratepayers, and CETA strongly endorses such a line as one of the few potential transmission projects it intends to prioritize. What we lack is (1) rigorous modeling to determine the potential for economically advantageous trades across such a line; (2) an assessment of costs and benefits rigorous enough to determine whether it is sensible to move forward with project development; and (3) a comprehensive understanding of the regulatory approvals from FERC, relevant state utility Commissions, and the Moffat and Hayden County Commissions that would be needed if a decision were made to build the line.

598. Given the positive indicative results from the 2021 ERP/CEP, we require the Company to rigorously develop the information identified as missing in the previous paragraph. We therefore direct the Company to work with CETA and its contractors to develop a consensus optimal route for a high voltage transmission link to the Pacificorp Gateway South line and to develop the modeling parameters necessary to accurately quantify the potential costs and benefits of this link. We further direct the Company to submit a report in this Proceeding within 18 months

presenting both its cost-benefit analysis of this line and any unique process-related issues that developing the line might pose.

4. Large Load Transmission Study

599. At hearing, Chair Blank discussed with the Company the possibility of evaluating the transmission impacts of locating much of the large loads the Company is forecasting on the high side of the 345 kV system, and thus outside of the Denver Metro Constraint. The Company indicated a willingness to conduct this modeling at hearing.[510] In its SOP, the Company recommends several modifications to the study Chair Blank outlined, which it states align with ongoing market developments, trends and studies already in progress. The Company recommends the following parameters:

- An EnCompass run based on the Company's Rebuttal Testimony Updated Base Forecast, with updated generic pricing assumptions, including tax reform impacts. The EnCompass run will also include several topology sensitivities, all focused around Data Center Row and the Smoky Hill and Spruce substations;
- Power flow analysis that includes (1) updated generation portfolio and dispatch assumptions; and (2) updated load forecasts.

600. The Company proposes to conduct these analyses under three load scenarios: a no large load scenario; a scenario assuming the large loads in the updated base forecast (about 950 MW); and a high large load forecast (ranging from about six to ten GW) based on the status of the Company's queue and anticipated demand in early third quarter 2025. The Company suggests that these scenarios will enable the Company and Commission to better understand the magnitude of potential system costs that future large loads may drive. The Company states that it can commit to

[510] Hr. Tr. June 20, 2025, pp. 210-213.

filing this "Large Load Transmission Study" in conjunction with its Large Load Tariff filing in January 2026 if the Commission approves its proposed approach.[511]

601. While we appreciate the Company's proposal, we find that it will not adequately identify the transmission costs that could be imposed on ratepayers by allowing developers to site new large loads within the Denver Metro constraint as opposed to assuming that these facilities are constructed outside of the constraint or on the high side of the 345 kV transformers that serve Denver.

[511] Public Service's SOP at pp. 24-25.

602. Accordingly, we require the Company to conduct the following modeling studies:

- A revised EnCompass run based on the Company's Low Load Forecast as adjusted by the Commission's decision in this case regarding EV and BE loads and with updated generic resource cost and tax reform assumptions.
- A second EnCompass run that includes an additional 2,000 MW of large data center load over and above what's included in the first Encompass run above. This additional load is to ramp up in alignment with the ramping assumptions the Company used in its original Base forecast.
- Power flow and transmission capacity expansion analysis for the following three scenarios: (1) assuming that the new large loads are limited to existing customers as in the low load forecast; (2) that the 2,000 MW of additional load in the second Encompass run comes online around Data Center row within the transmission-constrained Denver Metro area on the 230 kV system or below; and (3) the 2,000 MW of new load comes online outside the Denver Metro area on the 345 kV system or on the high-voltage side of the Daniles Park and Smoky Hill substations.

603. These modeling studies are to be completed, and their results filed in this Proceeding no later than the January 31, 2026 Large Load Tariff filing date. We expect that these modeling results will be reflected in the direct testimony the Company files in support of that tariff.

R. Performance Incentive Mechanisms

1. Cost-to-Construct ("CtC") and Operational PIMs versus Three-Party PIM

a. Party Positions

604. In Phase II of the 2021 ERP/CEP three parties (Staff, UCA, and CEC) advanced a new type of PIM for utility-owned generation in which Public Service would be required to recover the costs of Company-owned renewable generation assets entirely through the ECA as opposed to base rates. Under this Three-Party PIM, cost recovery increases in direct proportion to the amount of renewable energy the assets produce while also tying cost recovery to Public Service's Phase II bids. Likewise, the PIM would account for both capital construction costs and performance of the assets. While the Commission declined to adopt the Three-Party PIM in the 2021 ERP/CEP, we

opined that the approach offered a potential avenue to engage in performance based regulation on a more fundamental level as opposed to simply overlaying PIMs on top of the standard cost of service ratemaking. The Commission expressed an intent to further evaluate the Three-Party PIM in the JTS.[512]

605. In this Proceeding, Public Service vehemently opposes the Three-Party PIM. The Company argues the PIM would compensate the utility strictly based on production, breaking the cost of service ratemaking construct entirely, and essentially deregulating cost recovery for impacted generation projects.[513] In Rebuttal, the Company even opposes Staff's request to provide additional reporting in subsequent proceedings that may help evaluate whether the future implementation of the Three-Party PIM is appropriate. The Company argues it already has numerous reporting obligations and that adding a hypothetical calculation to the reporting mix is unnecessary, burdensome, and likely confusing.[514]

606. Instead of the Three-Party PIM, Public Service recommends the Commission continue to develop the CtC and operational PIMs for any utility-owned generation projects arising from the JTS.[515] The Company argues the exact mechanics of such PIMs should be considered in a separate future proceeding in which the parties can iterate on and evolve the approach recommended in the unopposed settlement agreement in Proceeding No. 24A-0417E.[516]

607. Staff argues the Commission should order cost-to-construction and operational PIMs for Company-owned projects in this JTS consistent with the 2021 ERP/CEP and does not recommend approving the Three-Party PIM at this time. Staff explains, however, that it continues

[512] Phase II Decision at ¶¶ 196-98 issued in the 2021 ERP/CEP (January 23, 2024).
[513] Hr. Ex. 101, Ihle Direct, Rev. 1, pp. 92-94.
[514] Hr. Ex. 117, Ihle Rebuttal, p. 92.
[515] Hr. Ex. 101, Ihle Direct, Rev. 1, pp. 92-94.
[516] Public Service's SOP, Attachment A.

to remain interested in such an approach moving forward. If the Commission is also interested, Staff recommends the Commission order the Company to provide an annual calculation comparing the (1) the as-bid project revenue requirement and unit performance with (2) the actual performance of the generating asset and actual cost recovery. Staff argues the Company could provide this comparison in the annual ECA prudence review proceeding or another proceeding where the Company reports the results of on-going operational PIMs.[517]

608. Staff disagrees with the Company's arguments that such a reporting requirement would be "unnecessary, burdensome, and likely confusing," arguing instead that such reporting would provide the Commission a straightforward and transparent comparison of both the Company's actual performance compared to its ERP bidding and the Company's cost recovery compared to PPA projects.[518]

609. UCA continues to advocate for the Three-Party PIM, arguing that it would put Public Service on equal footing with other entities bidding into the ERP process such as IPPs. If the Commission is not inclined to do adopt the three-party PIM, then UCA suggests that any consideration of PIMs should be left to CPCN proceedings stemming from this ERP for any Company-owned generation.[519]

610. Climax argues that PIMs for utility-owned projects should not be set or considered in this Proceeding. Instead, Climax argues that such PIMs should be considered in associated CPCN proceedings guided by the same parameters applied to Colorado Power Pathway projects.[520]

[517] Staff's SOP at p. 28.
[518] Staff's SOP at pp. 27-28.
[519] UCA's SOP at p. 32.
[520] Climax's SOP at p. 6.

b. Findings and Conclusions

611. Given the capital bias that exists in current cost-of-service regulation, where utility earnings growth is directly linked to capital spending and rate base expansion, we continue to have serious concerns with the projected growth in Public Service's rate base and the potential impacts on customer bills and rates, all in the context of customer service failings. In this context, we are committed to finding ways to move towards more performance-based regulation in which the Company prioritizes performance over capital spending. In short, this Commission continues to see a need to align customer and Company incentives. The CtC and operational PIMs in their current form, while very helpful in partially aligning certain construction and performance-related risks as between customers and the utility, do not fully address these concerns.

612. Turning to the three-party PIM, we continue to find this PIM intriguing because it offers a potential avenue to engage in performance based regulation on a more fundamental level as opposed to simply overlaying PIMs on top of the standard cost of service ratemaking. Although much of the Company's opposition to the three-party PIM appears to be overstated, we agree with Public Service that shifting to the three-party PIM would mark a major shift in how the Commission regulates Company-owned generation. Given the likely magnitude of its impact and the relatively thin record in this Proceeding, we agree with Staff that the Commission should not attempt to implement the three-party PIM in this Proceeding.

613. To continue evaluating this PIM, however, we adopt Staff's suggested reporting requirements in which the Company provides an annual calculation in the ECA comparing (1) the as-bid project revenue requirement and unit performance with (2) the actual performance of the generating asset and actual cost recovery. For the reasons set forth by Staff, we find the Company's arguments against this reporting to be unpersuasive. Such reporting could provide critical

information if the Commission decides to adopt the three-party PIM in the 2028 ERP. In this vein, Public Service shall provide this reporting on utility-owned assets not just from this JTS but also on the utility-owned assets arising from the 2021 ERP/CEP.

614. We further grant Staff's recommendation and direct that the CtC and operational PIMs will apply to Company-owned projects arising from this JTS. Although the Commission can continue to address the details of these PIMs in subsequent CPCNs (directionally consistent with recommendations from UCA, Climax, and the Company), we reaffirm that the Company's Phase II bids[521] will set the baselines for the PIMs, unless the Company can show the existence of extraordinary circumstances. As such, for purposes of the PIM calculation, Public Service shall file as part of the 120-Day Report the capital construction cost and associated AFUDC for each utility-owned bid as well as the capacity factor and levelized cost of energy for each utility-owned renewable bid. Regardless of whether the CtC and operational PIMs change going forward to better address our desire to shift toward performance based regulation, the baselines for these PIMs will be the bid metrics Public Service uses in the Phase II bid evaluation and selection.

615. The Commission disagrees with suggestions from UCA, Climax, and the Company that the CtC and operational PIMs should be entirely deferred to future proceedings. These PIMs may change the level of risk the Company assumes for utility-owned projects. The Company should be able to incorporate this risk into its Phase II bids.

2. Emissions PIM

616. In its Direct, Public Service also puts forth a proposed emissions reduction PIM that it previously discussed with stakeholders (*i.e.* Staff, WRA, and CEO). The Company notes, however, that the Company and parties have not reached a consensus recommendation for an

[521] To be clear, this includes both Company-built assets and build-transfer-own assets.

emissions reduction PIM. Ultimately, Public Service does not endorse the emissions reduction PIM. The Company states that the intent of such a PIM is laudable, but the practical application of an emissions PIM that utilizes the as-modeled emissions reductions as the threshold for earning an incentive may be unworkable.[522] Public Service recommends the Commission defer consideration of an emissions PIM to a future proceeding. [523]

617. Regarding the emissions reduction PIM, Staff recommends against approving the PIM in this Proceeding. Given concerns about the complexity and viability of an emissions PIM, risks of higher costs to ratepayers, and the lack of consistency with the Commission's prior PIM guidance, Staff states that it agrees with the Company, UCA, WRA and SWEEP, and CEO that an emissions PIM should not be adopted at this time.[524]

618. WRA and SWEEP recommend that, instead of approving the emissions PIM, the Commission should approve a set of Phase II portfolios and solution sets that will allow for robust evaluation of accelerated decarbonization in Phase II.

619. We agree with the parties that the Commission should refrain from attempting to implement an emissions reduction PIM in this Proceeding. We reiterate, however, that one of our primary policy objectives is to achieve cost-effective emissions reductions. The fact that the parties were unable to bring forward a holistic emissions reduction PIM does not lessen the importance of this objective, especially as we endeavor to focus more directly on the Company's performance in rate making.

[522] Hr. Ex. 101, Ihle Direct, Rev. 1, p. 107.
[523] Public Service's SOP, Attachment A.
[524] Staff's SOP at p. 27.

S. 24/7 Carbon Free Energy Community Programs

1. Party Positions

620. In its Direct, Public Service puts forth a "program concept" for a 24/7 Carbon Free Energy ("CFE") acquisition strategy that aims to match a participating customer's electricity consumption with carbon-free generation on an hourly basis. The Company requests the Commission approve its proposed strategy to acquire resources for future 24/7 CFE programs from its RFPs that are higher in the bid stack than (*i.e.*, incremental to) the resources selected to meet the rest of its future customers following an approved ERP.

621. Staff argues that the Commission should deny as premature the Company's proposed plan for acquiring resources for a yet-to-be developed 24/7 CFE. Staff asserts zero emissions community programs face growing challenges, including a lack of customer interest and are "purely hypothetical at this stage."[525] Staff argues the Commission should not approve how resources for these programs will be acquired until the Company introduces actual, well-defined programs for approval.

622. CEO is generally supportive of the CFE program but has the following five recommendations: (1) ensure that the program is tariff-based so 24/7 CFE program participants bear the entire cost of the program; (2) acquire CFE resources from the Phase II bids that remain after the approved and backup bid portfolios are developed; (3) expand the CFE offering to new large loads; (4) at least for new large loads, the CFE should include minimum contract lengths, walk-away penalties, and minimum billing demand to reduce the chance of those large customers

[525] Staff's SOP at p. 36.

leaving the program; and (5) subtract the projected load for the 24/7 CFE program from the ERP forecast before allowing the Company to acquire incremental 24/7 CFE resources.[526]

623. CC4CA argues the Commission should direct the Company to require hourly renewable energy credit ("REC") tracking of all eligible energy resources acquired via the JTS. CC4CA argues that current voluntary renewable products are designed for customers to "offset" consumption with renewable electricity but renewable production is not intentionally matched with customer consumption. Tracking RECs on an hourly basis supports development of the next generation of voluntary renewable products so that customers do not claim to be "100% renewable" while still consuming fossil fuel electricity.[527]

624. CC4CA opposes the Company's proposal that CFE resources be acquired only as incremental resources to the ERP resources. CC4CA asserts it is premature to find that this is the only or most effective pathway to 24/7 CFE. CC4CA suggests, for example, that a CFE program could pay for any incremental cost of zero emissions resources to include the bids in the approved portfolio. CC4CA recommends the 120-Day Report include discussion of three scenarios: (1) the potential for a CFE product to lead to the selection of a portfolio that provides additional emissions reduction compared to the Preferred Portfolio; (2) the potential for the capacity of one or more renewable bids included within the Preferred Portfolio to be expanded to serve CFE customers, as reflected in bid variations submitted in the competitive solicitation; and (3) the potential for innovative clean technology bids to be developed by CFE customers in lieu of the CFFD proposal.[528]

[526] Hr. Ex. 400, Hay Answer, pp. 62-64.
[527] CC4CA's SOP at p. 13.
[528] CC4CA's SOP at p. 14.

625. CC4CA further requests the Commission require Public Service to convene a stakeholder group to refine a CFE product that could develop CFE resources through the incremental need pool or to solicit them through the supplemental RFP. CC4CA asserts that at the evidentiary hearing Public Service expressed a willingness to continue conversations with customers and communities regarding 24/7 CFE.

626. In sum, CC4CA ultimately recommends the Commission require (1) hourly REC tracking of acquired eligible energy resources; (2) convene stakeholders to continue development of a 24/7 CFE product; and (3) consider development of CFE product based on CFFD technology bids received in Phase II.[529]

627. In Rebuttal, Public Service agrees that additional development will be necessary for a CFE program and recommends this additional development occur in a future filing. Public Service reiterates its initial recommendation, however, that the Commission affirm that CFE-serving resources should be "next in line" after approved and backup bids in an ERP-type solicitation.[530]

2. Findings and Conclusions

628. We reject Public Service's request to determine at this stage that CFE resources be acquired only as incremental resources or "next in line" to the approved ERP resources. We agree with CC4CA that it would be premature to find that that this is the only or most effective pathway to 24/7 CFE. For instance, resources developed through the CFFD or VPP resources should not be precluded from future 24/7 CFE community programs. We grant CC4CA's request and require Public Service to convene a stakeholder group to further refine the details of a CFE product.

[529] CC4CA's SOP at p. 30.
[530] Hr. Ex. 117, Ihle Rebuttal, p. 98.

629. We reject the remaining requests from CC4CA and CEO. The specifics of how a future CFE program should be designed and tracked (including through hourly REC tracking) are best left for the stakeholder group or a future filing when there is a concrete proposal.

T. Mapping

1. Party Positions

630. In the 2021 ERP/CEP, the Company provided maps showing the location of various bids as well as heatmaps showing things like net load and curtailments. In this Proceeding several intervenors argue that Public Service should be required to provide similar data in the Phase II of this Proceeding. For example, CEO requests public maps of bids relative to DI communities, including a web-based GIS map that shows generalized locations of all bids included in Phase II portfolios, the geographic areas of DI Communities, and the geographic areas where bids receive modeling credits or adders. [531]

631. CC4CA and Healthy Air and Water both support CEO's mapping requests and ask for additional information concerning the location of bids and the Denver Metro/North Front Range Ozone Nonattainment Area ("NAA"). CC4CA specifically requests one map illustrating the relationship between bids and the NAA and another map showing an overlay of the NAA in a cost-free, web-based GIS map that can be accessed by parties with signed NDAs that shows specific locations of bids included in portfolios in relationship to DI communities and locations of bonus credits. CC4CA argues that such maps will help show the burden that new gas plants may have on the NAA.[532] Healthy Air and Water similarly recommends CEO's requested maps also show new generation facilities proposed within the NAA. Healthy Air and Water argue that this

[531] CEO's SOP at p. 9.
[532] CC4CA's SOP at p. 8.

Commission and stakeholders should have a straightforward and accessible way to understand which new generation facilities are proposed to be located within the NAA.[533]

[533] HAWC's SOP at p. 17.

632. CRES/PSR requests that the Company should again provide heat maps showing things like net load and curtailment, but CRES/PSR requests that such heat maps provide additional information such as the modeled fossil fuel dispatch and modeled storage discharge. CRES/PSR argue that the heat map data provided in the 120-Day Report were useful in subsequent proceedings to represent the trends in the hourly profiles of load, net load, and renewable curtailment.[534] For purposes of the JTS, CRES/PSR request the following heat map information, in the same 24 x 12 format as the 2021 ERP/CEP:

a. Modeled average CO_2 emissions intensity (lbs/kWh or similar intensity metric)
b. Modeled load (MW)
c. Modeled storage discharge (positive) and charge (negative), (MW)
d. Modeled available renewables without curtailment (MW)
e. Modeled fossil fuel dispatch (MW)
f. Modeled net load = (Modelled load – renewables without curtailment) (MW)
g. Modeled curtailment of solar (MW);
h. Modeled curtailment of wind (MW), and
i. Modeled hours with curtailment. (Hours)[535]

633. Public Service does not appear to respond to these various requests in its SOP or Rebuttal.

2. Findings and Conclusions

634. We grant CEO's mapping requests and direct Public Service to include the following in the 120-Day Report: (1) a public PDF map of bids relative to DI communities (2) a public PDF map of bids relative to geographic locations where bids receive modeling credits or adders as approved by the Commission in Phase I; and (3) a web-based GIS map that shows

[534] CRES/PSR's SOP at p. 11.
[535] CRES/PSR's SOP at p. 28.

generalized locations of all bids included in Phase II portfolios, the geographic areas of DI Communities, and the geographic areas where bids receive modeling credits or adders.

635. Similar mapping regarding DI communities was provided in Phase II of the 2021 ERP/CEP, and these requests from CEO are supported by CC4CA and Healthy Air and Water.

636. We reject, however, requests from CC4CA and Healthy Air and Water for maps showing bids in relation to the Denver Metro/North Front Range Ozone NAA. Regardless of the portfolio of resources the Commission approves in Phase II, projects will need to obtain all applicable permits, including air quality permits. Analyzing projects based on their presumed impacts on the ozone NAA is better left to the air permitting authorities.

637. Finally, we grant CRES/PSR's request for heat map information, including, among other things, data on modeled net load, modeled available renewables without curtailment, and modeled curtailment of wind and solar. The Company committed to providing similar information in the 2021 ERP/CEP and we agree with CRES/PSR regarding the usefulness of such information.

U. Best Value Employment Metrics

1. Party Positions

638. In light of the passage of SB 23-292, Public Service proposes to fashion the RFP bidding documents such that bidders are required to acknowledge and adhere to labor standards set forth in the Commission's rules regarding BVEM and abide by SB 23-292 and the apprenticeship utilization law and prevailing wage law, unless otherwise covered by a Project Labor Agreement.[536]

639. Similar to the 2021 ERP/CEP, Public Service has retained a labor economist to provide a BVEM score for all bids advanced to computer-based modeling based on the BVEM

[536] Hr. Ex. 104, Bornhofen Direct, pp. 36-37.

information provided. As part of its Phase II Bid Evaluation Report, the Company will provide the labor economist's cumulative BVEM score for each portfolio presented based on the BVEM scores of the bids in the portfolio. [537] The Pueblo Intervenors support the Company's labor scoring proposals, arguing that a bidding process that only advances "least cost" projects is counterproductive to our community and undercuts good labor practices.[538]

640. In a public comment, Laborers' International Union of North America Local 720 ("Local 720"). Local 720 urges the Commission to require Public Service to adopt the same union labor provisions for PPAs in Colorado that its Minnesota subsidiary uses.

2. Findings and Conclusions

641. In all decisions involved in ERPs § 40-2-129(1)(a)(I), C.R.S. requires the Commission to consider best value regarding employment of Colorado labor and positive impacts on the long-term economic viability of Colorado communities. To this end, we must require utilities to obtain and provide to the Commission information regarding "best value" employment metrics. The precise information that is required is defined by statute.

642. Public Service has put forth a reasonable approach to ensuring that the Commission has the necessary information to consider BVEM, including the Company's proposal to procure a labor economist to calculate a BVEM score for each portfolio presented in Phase II. Conversely, there is insufficient evidence on this record to require Public Service to adopt the union labor provisions that Xcel's Minnesota subsidiary uses. Moreover, we note the PPAs already require the Seller to certify they are complying with Senate Bill 23-292 and the associated apprenticeship utilization law and prevailing wage law or are otherwise covered by a Project Labor Agreement.

[537] Hr. Ex. 101, Att. JWI-3, Vol. 3, Rev. 1, p. 33.
[538] Hr. Ex. 1202, Swearingen Answer, p. 8.

643. Thus, we direct Public Service to ensure that provision and presentation of BVEM rules during Phase II of this Proceeding (both the base RFP and supplemental RFP) fully comply with the statutory requirements.

V. Holy Cross's Requests

1. Party Positions

644. In its SOP, Holy Cross seeks to reaffirm its rights under Paragraph 46 of the USA from the 2021 ERP/CEP. Paragraph 46 of the USA states the following:

> Holy Cross, in its sole discretion, shall have the option to select one or more replacement resources owned by or contracted to Holy Cross and interconnected with the Integrated Transmission System (as that term is defined in the PSCo-HCE Transmission Integration and Equalization Agreement) that will be provided appropriate transmission access, capacity accreditation entitlement and equivalent capacity credit associated with the Facility under the PSCo-HCE Power Supply Agreement, to the extent it is still in effect, by the Company following the early retirement of the Facility in an amount not to exceed Holy Cross' existing volumes from the Facility as of the date of this agreement. These may include projects selected by Holy Cross through the Pueblo Just Transition Resource Solicitation after the portfolio necessary to serve the Company's retail customers has been selected.[539]

645. Holy Cross asserts that Commission guidance interpreting paragraph 46 the USA is important for Public Service, Holy Cross, and bidders to effectuate the Unit 3 retirement and replacement process. If the Commission determines that it is not appropriate to provide the guidance requested by this statement in its Phase I decision regarding the Phase II process, then Holy Cross requests that its arguments be allowed to be raised again in Phase II without prejudice.

646. Holy Cross requests the Commission make numerous legal conclusions regarding paragraph 46. For instance, Holy Cross argues that its rights under paragraph 46 apply to the base RFP as well as the supplemental RFP and that Holy Cross has the same ability to review the JTS

[539] 2021 ERP/CEP USA at ¶ 46.

bid packages as the IE, Staff, and UCA. Holy Cross also asserts that it need not wait for both JTS RFPs to be complete before selecting project. Instead, Holy Cross argues it should be allowed to have its replacement capacity contracted and online in a similar manner to the replacement capacity in-service dates required by Public Service, which means it may select from resources after completion of the base RFP. Holy Cross acknowledges that it cannot select its replacement resources until after the Phase II Decision is final but asserts that it should not be required to wait until the Commission resolves applications for RRR or other delays associated with an aspect of the Phase II Decision that does not impact the approved portfolio.

647. To communicate Holy Cross's rights under the USA, Holy Cross and

648. Public Service agree to add the following paragraph to the RFP:

> **1.7 Holy Cross Comanche 3 Replacement Capacity**. After Public Service's resource portfolio is approved by the Commission, Holy Cross Electric Association may select resources from the bids submitted to this RFP to replace some or all of its 60 MW Comanche 3 capacity entitlement. Please see holycross.com/JTSRFP for more information.[540]

649. In addition, Holy Cross asserts that, per the USA, Public Service will provide transmission access sufficient to deliver energy from Holy Cross's replacement capacity to the Holy Cross points of delivery on the Public Service transmission system.

2. Findings and Conclusions

650. As Holy Cross's SOP demonstrates, the development of the Phase II Framework complicates the rights afforded to Holy Cross under paragraph 46 of the USA. Moreover, the issue regarding Holy Cross's rights under paragraph 46 were raised for the first time in Holy Cross's SOP. The Commission does not have the benefit of party feedback. Accordingly, we decline to make the requested legal conclusions in this Decision.

[540] Holy Cross's SOP at p. 8.

651. Rather than attempt to craft a way forward on such a limited record, we direct Public Service to confer with Holy Cross on these issues and come back to the Commission with any proposed solutions. Thus, 30 days prior to the RFP issuance, Public Service must file a notice setting forth the results of its conferral with Holy Cross. The Company may also include updated language in the RFP alerting bidders to the rights that Holy Cross has pursuant to the 2021 ERP/CEP USA.

W. Pueblo Energy Park

1. Party Positions

652. In its Answer, EJC proposes the concept of a renewable energy park in Pueblo. EJC explains that renewable energy parks have the following four components: (1) renewable energy, which is primarily wind and solar; (2) short-duration battery storage; (3) industrial customers with flexible loads; and (4) long-duration energy storage in the form of flexible technologies that can both store energy and reconvert it to electricity.[541] EJC argues a renewable energy park could be critical in achieving a just transition in Pueblo. EJC cites a report from Energy Innovation that studied building a renewable energy park in Pueblo. The Energy Innovation report concludes that such a park would reliably replace the generation from the Pueblo coal plant, 40 percent of the energy generated would flow to Pueblo County, and the park could generate more than $40 million in annual property tax revenue and 350 permanent jobs in Pueblo.[542]

653. EJC urges the Commission to direct Public Service in its Phase I decision to convene a stakeholder process to study the development of a renewable energy park in Pueblo.

[541] EJC's SOP at p. 14.
[542] EJC's SOP at pp. 14-15.

EJC proposes that Public Service would file a report in this Proceeding no later than one year after the Commission's final Phase I decision that discusses and recommends the next steps for building a renewable energy park in Pueblo.[543] EJC warns that simply deferring this issue to the Phase II solicitation is highly unlikely to result in a successful renewable energy park bid because the renewable energy park concept requires components like flexible industrial loads and long duration energy storage.[544]

654. The Commission received numerous public comments discussing a renewable energy park, most of which were strongly supportive of the concept.

655. Public Service opposes the requirement to study the development of a renewable energy park in Pueblo, arguing that doing so would be redundant with the study Public Service conducted in Pueblo following the 2021 ERP/CEP, which resulted in the PIESAC Report. Public Service notes that it will accept all renewable and storage bids proposed in the Pueblo area as part of the Phase II all-source solicitation, including a renewable energy park if such a proposal is bid.[545]

2. Findings and Conclusions

656. The Energy Innovation Report reflects the advantages of co-locating flexible load and generation/storage as well as the potential economic advantages of such a system for Pueblo. This justifies additional evaluation of long duration energy storage and flexible large loads. We reject, however, EJC's primary request to require Public Service to study the concept of a renewable energy park in Pueblo. The Energy Innovation report that EJC submitted into the record already shows the potential benefits and existing challenges with deploying a renewable energy park. The report finds that one of the primary barriers to deploying an energy park is attracting

[543] EJC's SOP at p. 16.
[544] EJC's SOP at pp. 17-18.
[545] Hr. Ex. 118, Landrum Rebuttal, p. 91.

industrial customers to serve the crucial role of flexible load.[546] Similarly, one of the key components of a renewable energy park is the existence of long duration energy storage. For both of these components—industrial customers with flexible load and long duration energy storage—another stakeholder study in Pueblo is unlikely to yield material benefits.

657. Instead, we direct the Company to continue advancing efforts to develop load flexibility for large loads and long duration energy storage. At a minimum, Public Service shall address load flexibility in the new large load tariff filing. This aligns with the Company's inclusion of load flexibility in the commercial principles for large loads. Load flexibility could also be critical in advancing the possibility of a Clean Transition Tariff, which will also be addressed in the large load tariff filing. Regarding long duration energy storage, this technology appears to be a prime candidate for CFFD funding. The Commission therefore encourages Public Service to fully evaluate options to promote long duration energy storage through the CFFD process.

X. Updated Phase I Modeling

658. In its SOP, CEC notes the Company's Phase I modeling does not reflect several revised conditions such as increased generic costs described in the Company's Rebuttal, current tariff estimates, and the accelerated termination of clean energy tax credits. Regarding the increased generic costs, CEC cites Public Service's Rebuttal in which the Company warns that the cost assumptions used in the Phase I modeling may in some cases be half of the costs the Company reasonably expects to see in Phase II.[547] In light of the revised conditions, CEC recommends the Commission require Public Service to rerun its load forecasts, PVRR, long-term rate analysis, and

[546] Hr. Ex. 1701, Att. DS-4, pp. 22-23.
[547] CEC's SOP at p. 14 (citing Hr. Ex. 118, Landrum Rebuttal, p. 68).

capacity expansion models with inputs that reflect the best and most current information available for the increased generic costs, current tariff estimates, and the accelerated termination of clean energy tax credits.

659. We agree with CEC and direct Public Service to provide updated Phase I modeling by December 31, 2025. Consistent with CEC's request, this updated modeling shall include refreshed load forecasts, PVRR, long-term rate analysis, and capacity expansion models and shall use updated assumptions regarding increased generic costs, current tariff estimates, and the accelerated termination of clean energy tax credits. This updated modeling will help establish more accurate expectations for the pricing and resource procurement we may see in Phase II as well as additional context for the large load tariff filing.

Y. Omnibus Motion, IE, and Requested Variances

1. Extension of Phase II Timelines (Rules 3618(b)(I), 3613(a), 3613(d), and 3613(e)-(h))

a. Party Positions

660. Public Service argues in the Omnibus Motion[548] that the resource planning procedures have become increasingly complex over the course of the past several ERP cycles with an unprecedented number of submitted bids resulting in portfolios with several gigawatts of new resources and billions in new clean energy-related investments across the State of Colorado. The Company expects the 2024 JTS to be similarly complex and requests an extension of the Phase II deadlines.[549]

[548] In its Omnibus Motion, the Company requests waiver of Commission Rules 3606(b), 3612(a), 3618(b)(I), 3613(a), 3613(d), 3613(e)-(h), and 3608(c)(III)-(IV). In Decision No. C24-0941-I, issued December 23, 2024, the Commission addressed Rule 3606(b) (regarding load forecasts) and Rule 3612(a) (regarding the motion to approve an IE). All of the other requested rule waivers were deferred to a future decision.

[549] Omnibus Motion at pp. 19-20.

661. In its SOP, Staff argues that the Company's requested waivers of the Phase II deadlines (Rules 3618(b)(I), 3613(a), 3613(d), and 3613(e)-(h)) should all be denied. Staff notes that Public Service has not provided further testimony related to these requests or otherwise shown a need for timing extensions given the evolution of the Phase II Framework. Staff asserts the Phase II Framework and the relatively limited number of modeling portfolios proposed for Phase II should help ease the Company's concerns about deadlines. If the Company determines in Phase II that extensions are needed, Staff argues the Company can seek extensions as it did in the last ERP.[550]

662. CEO likewise opposes the Company's requested extension of the Phase II deadlines CEO still believes it is premature to approve any of the Company's requested waivers regarding Phase II deadlines. CEO acknowledges the complexity of the ERP presents a challenge during Phase II proceedings but maintains that adhering to the ERP regulatory deadlines is important to reducing uncertainty around project deliverability and maintaining the timing of the Framework.[551]

663. CEI also opposes the Company's requested extension of the Phase II deadlines. CEI argues that after the passage of the federal Reconciliation Bill, time is of the essence for Colorado to purchase renewable energy that can qualify for the existing ITC/PTC credits as quickly as possible to maximize savings to ratepayers. In fact, CEI argues that it is critical for the Commission to issue a Phase II Decision before July 4, 2026, to ensure that bidders and Company-owned projects are able to take the steps necessary to safe-harbor projects and increase the chances of qualifying for ITC/PTC tax credits. CEI puts forth a proposal for an expedited Phase II schedule in which the RFP would issue by October 31, 2025, and the 120-Day Report

[550] Staff's SOP at p. 33.
[551] CEO's SOP at p. 12.

would be filed by March 1, 2026. Under CEI's expedited schedule, the Phase II Decision would issue on June 1, 2026.[552]

b. Findings and Conclusions

664. For the reasons set forth by Staff and CEO, we deny the Company's requested waivers regarding extensions of the Phase II timelines (*i.e.*, Commission Rules 3606(b), 3612(a), 3618(b)(I), 3613(a), 3613(d), 3613(e)-(h)). The Commission expects that the decisions made in Phase I (*e.g.* limiting bid variations that do not require a separate bid fee and largely approving the Phase II Framework with a reduced load forecast) make the Phase II bid evaluation and selection process more efficient. In addition, Public Service now has more experience with EnCompass, which should result in fewer unforeseen modeling issues.

665. While agree with CEI that the federal Reconciliation Bill added additional time pressures for the acquisition of renewable energy resources, we decline to adopt CEI's expedited schedule. As Staff notes, if Public Service needs additional time, the Company can file motions for extension of time like it did in the 2021 ERP/CEP.

2. Injection Capacity

a. Party Positions

666. As part of the Omnibus Motion, the Company requests a waiver of Rules 3608(c)(III)-(IV), which require information on injection capacities of all transmission assets. The Company contends that providing a fixed injection capability to any location on the system is misleading because the injection capability determined for a given location in the transmission system is highly dependent on the assumed generation and storage dispatch pattern. Therefore, the maximum injection capability corresponds only to the most favorable system

[552] CEI's SOP at pp. 31-32.

condition expected to occur. Because this system condition rarely occurs, the Company contends, an injection capability number by specific location is not a valid metric for the actual injection capability.

667. UCA argues that injection capability needs to be reported in Phase I so that bidders can determine where to site their projects in Phase II. UCA argues that despite its repeated requests, the Company failed to provide information about injection capability in the discovery process. UCA contends that the absence of this information gives the Company an unfair advantage over independent developers. UCA therefore recommends that the Commission require the Company to provide interconnection capability information prior to the base RFP.[553]

668. Interwest recommends the Commission direct the Company to provide transparent, timely, and actionable information for generation interconnection customers to identify available or low-cost headroom based on recent studies of transmission capability at interconnection points on the Company's system. Interwest also requests that basic technical information about the potential interconnection points, such as the status of terminal bays, presence of fiber options, flowgate data, and any known limiting element(s) at a potential interconnection point should also be made publicly available.[554]

669. Staff supports the Company's requested waiver but notes the Company does have an on-going responsibility to describe the dynamic nature of its transmission system, how it is modeled, and how it changes under different scenarios. Staff states that it "expects the Company to provide complete explanations and responses to discovery requests reasonably calculated to better understand transmission transfer capabilities."[555]

[553] UCA's SOP at p. 30.
[554] Hr. Ex. 501, Wilson Answer, pp. 33, 47.
[555] Staff's Response to Public Service's Omnibus Motion and Decision No. C24-0872-I, p. 4.

b. Findings and Conclusions

670. While we agree with the Company that injection capacity at any location is a very dynamic quantity, UCA's arguments that developers need information on available injection capacity, and that the absence of this information may give the Company a competitive advantage are also valid. Accordingly, we grant the Company's waiver request, but we also direct the Company to utilize historic SCADA data to provide statistical information on interconnection points of interest to developers. Specifically, for each interconnection point at which the Company has received either commercial inquiries or formal requests for interconnection studies from developers over the last two years, the Company shall make the following data available to developers: (1) the maximum capacity available in the most recently completed calendar year; (2) the number of hours in the most recently completed calendar year available capacity fell into each of ten bins, each representing ten percent of the maximum; and (3) the mean, median and standard deviation of available capacity over the most recently completed calendar year.

671. Should the above directive prove unduly burdensome, the Company may use alternative, commercially reasonable approaches to characterize available capacity at interconnection points of interest to developers.

3. Motion for IE Approval

672. As part of the Omnibus Motion, the Company requested a waiver of Rule 3612(a)'s timing requirement to file for Commission approval of an IE jointly proposed by Staff and UCA, until two weeks prior to the Phase I hearing. In Decision No. C24-0941-I, the Commission granted this request such that the Company had until two weeks prior to the Phase I hearing to file for Commission approval of an IE jointly proposed by Staff and UCA.[556]

[556] Decision No. C24-0941-I at ¶ 44.

673. Contrary to the Commission's directive in Decision No. C24-0941-I, Public Service has not filed a Motion to Approve an IE. The Company shall file this Motion, with the required conferral, as soon as reasonably practicable, but no later than two weeks prior to the issuance of the base RFP.

4. IE Conferral with Developers

674. Traditionally, the IE's scope of work has focused on ensuring the Phase II bid evaluation and selection process is conducted fairly. We find it necessary, however, to expand the IE's scope of work to include conferral with developers to increase the transparency regarding the negotiation process between Public Service and developers. The Company experienced several challenges negotiating PPAs in the 2021 ERP/CEP, and these challenges contributed to delays, price increases, and a higher likelihood that PPA projects fail during the negotiation process.[557] Despite these challenges, the Commission has relatively little insight into the negotiation process. With limited exceptions, individual developers do not intervene in ERP proceedings. Moreover, developers may be unwilling to openly discuss the challenges experienced in negotiations.

675. To increase transparency regarding the negotiation process, we direct Public Service, with conferral from Staff, UCA, and CIEA, to expand the IE's scope of work to require the IE to create a confidential channel through which bidders have the option to anonymously report their experiences negotiating with Public Service. This shall include both negotiations that resulted in executed PPAs and failed negotiations for which no PPA was executed. The IE will then compile these communications and file regular reports, possibly in the form of anonymous survey results, that stakeholders and the Commission can review. The goal is

[557] *See* Hr. Ex. 104, Bornhofen Direct, p. 15.

to create a more direct communication link between bidders and the Commission that would provide additional insight into the causes of the recent negotiation challenges including lengthy timelines and failed bid negotiations. We acknowledge this increased scope of work will result in higher costs for the IE. It is evident, however, that the negotiation challenges between bidders and the Company have already resulted in significant costs. The additional transparency into the negotiation process will better enable the Commission to enact targeted solutions.

676. In the interest of more quickly obtaining this additional transparency, this new IE task shall cover not just the PPA negotiations arising from this JTS but also the negotiations associated with the 2021 ERP/CEP projects. In other words, the IE must not wait until the JTS bidder negotiations to begin conferring with developers but shall start as soon as reasonably possible collecting information regarding the negotiations for the 2021 ERP/CEP projects.

677. The Commission will review the details of the new IE task when Public Service submits its Motion for IE approval, which shall include the IE scope of work.

5. Variances Needed for Phase II Framework

678. Staff recommends a permanent variance to paragraph 97 of Decision No. C22-0459 to allow for the JTS RAP to extend through 2033 as contemplated under the JTS Phase II Framework, particularly for the JTS supplemental RFP. Given the multiple RFPs provided under the JTS Phase II Framework, Staff argues the RAP extension will ensure more flexibility and allow for greater project participation in Phase II.

679. Staff also requests waiver of the deadline for the ERP following the JTS. In the 2021 ERP/CEP, the settling parties agreed to an October 31, 2026 deadline for filing of the Company's next ERP but left open the possibility for a variance to this deadline based on future circumstances. In Decision No. C22-0459, we approved this October 31, 2026 deadline.

Here, Staff recommends a permanent variance to paragraph 45 of Decision No. C22-0459 to move the deadline for filing of the Company's next ERP to 2028 consistent with the Phase II Framework. Staff further supports a similar variance to Rule 3603(a) as necessary.

680. For the reasons set forth by Staff, we grant a permanent variance to paragraph 97 of Decision No. C22-0459 to allow for the JTS RAP to extend through 2033. Similarly, we grant a permanent variance to paragraph 45 of Decision No. C22-0459 (and variance to Rule 3603(a), as necessary) to move the deadline for filing of the Company's next ERP to 2028 consistent with the Phase II Framework of the JTS

6. Variance from Rule 3206(b)(I)

a. Party Positions

681. Public Service requests a partial and permanent variance from Rule 3206(b)(I) such that (1) the Company need not request a CPCN for transmission lines that are constructed to serve a single customer which terminates at the customer premise and is paid for entirely, or the costs are directly assigned to, that customer; (2) the CPCN exception not be limited to those transmission facilities that are a "radial feed"; and (3) this variance be granted for all transmission facilities constructed for new large load customers that will take electric service from a "transmission line designed at 230 kV or above that serves a single retail customer and terminates at that customer's premises."[558]

682. The Company explains that under Rule 3206(a), a utility may not commence new construction of transmission facilities until either the Commission notifies the utility that such facilities do not require a CPCN or the Commission issues a CPCN. However, Commission Rule 3206(b)(I) states that a CPCN is not required for a radial transmission line

[558] Public Service's SOP, Att. A, at p. 4.

designed at 230 kW or above that serves a single retail customer and terminates at that customer's premises.

683. Public Service asserts it has a robust pipeline of potential large new customers that will require transmission level service to their facilities. According to the Company, granting this variance will reduce procedural hurdles and will enable the Company to interconnect these customers more quickly. Moreover, Public Service argues that allowing the Company to avoid the need to prepare and litigate such CPCNs will result in cost savings, and administrative efficiencies for the Commission and all parties.[559]

684. Staff argues that the Company's requested CPCN variance is premature, noting that the Company concedes that a decision on this point is not necessary in Phase I. Staff further warns that the Company's request appears to extend well beyond projects needed to implement the JTS. Further, although the Commission found that no CPCN was needed for certain projects serving a single customer in the past, in those instances the Commission had information about the scope, location, estimated costs, and justification for those particular projects. At this time, Staff asserts, the Commission and interested parties lack such information. Thus, Staff recommends the Commission deny the request and that the Company seek variances for specific projects as needed in appropriate future filings.[560]

b. Findings and Conclusions

685. For the reasons set forth by Staff, we deny as premature the Company's request for a partial and permanent variance from Rule 3206(b)(I). As Staff notes, as this point the

[559] Hr. Ex. 123, Bailey Rebuttal, p. 50.
[560] Staff's SOP at pp. 33-34.

Commission and interested parties lack information about the scope, location, estimated costs, and justification for the projects applicable to the Company's requested waiver.

7. 120-Day Timeline for post-JTS CPCNs

686. Public Service proposes that all post-ERP CPCNs should be based on a 120-day timeline, so long as the projects are consistent with the as-bid project.[561] The Company notes its request would still provide four months of process to evaluate projects requiring a CPCN—and more than that if the project is not consistent with the project as-bid. If the project as-bid has won in a competitive solicitation and the material terms of such remain consistent, the Company argues that eight to nine months of regulatory process for a CPCN proceeding is not necessary.[562]

687. Public Service reiterates this request in its SOP, arguing that follow-on CPCN filings are not requirements that IPPs have. In addition, the Company asserts resource adequacy and cost management considerations counsel in favor of the Commission granting this timing tool for use with Company-owned JTS projects in order to improve speed to operation and maximize capture of potential tax benefits.

688. Staff opposes the Company's request for several reasons. Staff notes the CPCN statute contemplates a base timeline of 120 days and that it is unclear what the Company means by "generally consistent" with the Phase II bid. Staff asserts the Company's proposal would make it difficult for parties to provide meaningful oversight and review of Company-owned generation resources. Staff also argues that deciding this issue in Phase I is premature because such decision unnecessary to conduct Phase II and the scope of these CPCN proceedings as well as potential conflicts with other proceedings are not yet known.

[561] Hr. Ex. 101, Ihle Direct, pp.76-77.
[562] Hr. Ex. 117, Ihle Rebuttal, p. 69.

689. We deny the Company's request as premature. The Company's request risks putting the burden on the Commission to quickly evaluate and determine whether a CPCN application is consistent with the Company's Phase II bid. Given the Commission's constrained resources, a more efficient path is for Public Service to work together with Staff, UCA, and other interested stakeholders prior to filing its CPCN applications. Interested stakeholders could agree in their interventions that the Company's application is consistent with its Phase II bid and there are no other unresolved issues, such as the utility-ownership PIMs. We emphasize that in such a situation where parties agree that an expedited timeline is appropriate, the Commission will work diligently to process the CPCN applications within such timeline.

Z. Adjudication Costs

1. Party Positions

690. The Company requests deferral of expenses related to consultant work, transcripts and hearing costs, and outside legal counsel. The Company also requests deferral of outside legal expenses associated with negotiating PPAs emanating from the approved JTS. Public Service estimates that the costs for consultants and outside witnesses, including for the labor economist and E3, will be $490,000. The Company anticipates incurring an approximate cost of $54,500 for the purchase of transcripts of the hearings and other hearing costs. Outside legal costs, including costs that will be incurred to assist with PPA negotiations, are expected to be $2.2 million.[563]

691. For most of these requests, the Company proposes to track the costs in a non-interest bearing regulatory asset that will be reviewed for recovery purposes in a future rate case

[563] Hr. Ex. 101, Ihle Direct, Rev. 1, pp. 126-28.

proceeding. However, Public Service requests to recover the costs of the independent facilitator associated with the CFFD, the labor economist, and IE through the ECA.[564]

692. UCA opposes the request to recover the labor economist fees through the ECA. UCA argues that fees associated with the labor economist should instead be included in the deferred account similar to the deferred account with other outside consultants.[565]

693. UCA also argues the Company should be directed to use any over-collection of bid fees to offset the adjudication costs in the deferred account. UCA suggests this offsetting could be done through accurate accounting of the costs of bid evaluation with bid fee receipts. UCA asserts the Company has not committed to refund excess bid fee collections to ratepayers and that a Commission order requiring this will promote the public interest. [566]

694. Other than the issues with the labor economist fees and the offsets from unused bid fees, UCA does not oppose the Company's deferral request, as long as the regulatory account does not include carrying costs.[567]

695. In Rebuttal, Public Service argues the labor economist fees are necessary for the evaluation of bids in the Phase II process, similar to the costs for the IE. For consistency, the Company asserts these costs should be treated the same and recovered in the ECA. The Company also opposes UCA's request regarding the bid fees, arguing the purpose of bid fees is to offset the Company's costs of evaluating bids during the Phase II process, not to offset the costs of prudently incurred expenses from litigating the JTS proceeding.[568] The Company further argues that UCA's recommendations regarding bid fees fail the acknowledge that bid fees cover real costs of bid

[564] Public Service's SOP, Att. A, at p. 3.
[565] UCA's SOP at p. 33.
[566] UCA's SOP at p. 33.
[567] Hr. Ex. 301, England Answer, pp. 23-24.
[568] Public Service's SOP at p. 31.

evaluation, which is particularly acute given the number of bids the Company receives and has to process in very short order.[569]

2. Findings and Conclusions

696. We grant the Company's request to cover the costs of the independent facilitator and the labor economist through the ECA. The labor economist concept was present in the 2021 ERP/CEP, where the settling parties agreed that the costs should be recovered via the ECA.[570] UCA's arguments do not justify changing this approach for purposes of the JTS. This same rationale supports ECA recovery for costs associated with the independent facilitator. As set forth above, however, the costs associated with the independent facilitator are included in the CFFD's budget cap. Regarding the IE, Public Service has not yet filed the Motion to approve an IE. We thus defer consideration of cost recovery for the IE until the decision ruling on the Motion to approve an IE.

697. In addition, we grant UCA's request that excess bid fees must offset the adjudication costs in the deferred account. It is unclear what costs the Company incurs in evaluating bids that it does not already recover elsewhere. Public Service shall provide an accounting of the costs of bid evaluation along with all bid fee receipts in the Company's next ERP Annual Report. To the extent there are any bid fees that are in excess of the Company's incremental costs of evaluating bids that are not recovered elsewhere, Public Service shall use such excess bid fees to offset the adjudication expenses.

698. In all other respects, we grant the Company's request to track and defer expenses related to consultant work, transcripts and hearing costs, and outside legal counsel costs in a

[569] Hr. Ex. 117, Ihle Rebuttal, p. 104.
[570] Decision No. C22-0459 at ¶¶ 155-56 issued in the 2021 ERP/CEP (Aug. 3, 2022).

non-interest bearing regulatory asset that will be reviewed for recovery purposes in a future rate case proceeding.

AA. Updates to Modeling Inputs and Assumptions

699. Section 2.11 of Volume 2 sets forth the inputs and assumptions Public Service intends to use in Phase II. These inputs and assumptions include capital structure and discount rate, gas price forecasts, inflation rates, and the ELCC and PRM values derived from the RA study. Section 2.11 also includes the inputs regarding the Company's demand and energy forecasts and projected resource capacity need. In Volume 2, Public Service states that, consistent with past practice, the Company will update the modeling inputs and assumptions as necessary.

700. During the hearing, Public Service specifically committed to provide an updated load forecast 30 days before the issuance of the RFP. The Company anticipated that this update would be "a full refresh of the load forecast" and include refinements to the Company's EV and PHEV forecasts.[571]

701. Except as modified in this Decision, the Commission approves the modeling inputs and assumptions outlined in Section 2.11 of Volume 2. In addition, consistent with past practice and the Company's commitments during the hearing, we direct Public Service to file, 30 days prior to issuing the base RFP, a complete list of the modeling inputs and assumptions consistent with the presentation in Section 2.11 of Volume 2 and indicate which parameters were updated for bid evaluation and selection purposes. To the extent that any parameters are still to be updated after the RFP is issued but prior to the Phase II resource evaluation, Public Service shall identify the updated parameters in the 120-Day Report. These updates shall be consistent with the Commission's other rulings in this Decision, including our directives on which large loads to

[571] Hr. Tr. June 23, 2025, pp. 64-65.

include in the load forecast, revisions to the Company's EV and BE estimates, the inclusion of an annual firm gas supply cost escalator, and updates to the costs of generic resources, including any changes made during the Company's rebuttal filing or at hearing to reflect evolving market conditions.[572]

702. Given the various changes we are directing Public Service to make in its RFP, the Commission further directs the Company to file its final RFP in this Proceeding at least 30 days prior to the RFP issuance. Consistent with our decision to adopt the Company's proposed process for reaching a final, non-negotiable PPA prior to the RFP, the Company must file its final, revised PPAs, incorporating all of the Commission's directives, at least 30 days prior to the RFP issuance.

BB. Conclusion

703. In this Phase I Decision, we establish the necessary guardrails within which Public Service may initiate an all-source, competitive bidding process to meet the Company's unprecedented resource need. Through the modified Phase II Framework, Public Service will move forward with a base RFP to acquire resources through 2031, a supplemental RFP to acquire additional resources through 2033, and a new ERP proceeding in 2028. In addition, the Company may use the incremental need pool to quickly respond to changes that the base RFP and supplemental RFP did not anticipate, and the Company can move forward immediately using the strategic reserve funds to begin the process of acquiring necessary transformers and breakers. This novel regulatory framework allows the Company to swiftly respond to the dynamic environment in which we find ourselves.

704. At the same time, the additional customer protections this Decision establishes help protect Colorado ratepayers from the risks associated with new large loads like data centers.

[572] *See. e.g.*, Hr. Ex. 135 (providing updated overnight construction costs for generic CTs).

We specifically reject the notion that existing ratepayers should bear the risk of rate increases if large loads fail to materialize or if the large loads fail to fully pay for their impacts to the electrical grid. This Decision sets clear steps that Public Service and prospective large loads must take to qualify for the streamlined regulatory process for acquiring additional resources through the modified Phase II Framework. If large load customers are willing to take such steps and commit to Colorado, the Commission is eager to support Public Service in acquiring new generation. We are unwilling to make existing customers pay for additional generation before such a commitment.

705. Importantly, this Decision also largely adopts the Company's proposed tools for ensuring a just transition. We maintain the basic framework for community assistance payments established in the 2021 ERP/CEP USA and extend them somewhat to provide payments based on the Company's ownership interests in Craig Unit 2. We also grant the Pueblo Intervenors' request to quantify the community assistance payments to Pueblo County and the underlying methodology and, in-line with the requests from the Routt County Governments, direct Public Service to propose a pathway to the dedication of the Hayden Station Spur Line, the Pumphouse Property, and any unused water rights currently benefiting Hayden Station. We acknowledge our rulings do not go as far as some parties request. Given that community assistance payments are funded by ratepayers, however, we ultimately agree with Staff that further expansion of community assistance payments will have affordability impacts on all ratepayers, including low-income customers.

706. Recognizing the testimony from various parties that capital investments in just transition communities are much more advantageous than temporary community assistance payments, we also largely approve requested mechanisms to drive new investments in these

communities. In addition to continuing the property tax offset modeling approach established in the 2021 ERP/CEP USA, we partly approve the Company's request to introduce new just transition modeling credits. Our decisions help ensure the Phase II modeling recognizes the true value of resources sited within just transition communities and does not simply select the least-cost resources. At the same time, our decision to pare back the full amount of the modeling credits addresses various concerns, including that using the full amount of the requested modeling credits is vulnerable to gaming and could allow developers to inflate the bid price of their projects. Another approved mechanism to drive new investment is the CFFD, which addresses barriers to the development of carbon-free firm dispatchable resources such as advanced geothermal and nuclear energy. An advisory board comprised of a broad group of stakeholders including members representing ratepayer advocates, the environmental community, the OJT, the Hayden community, the Pueblo community, Moffat County, and Morgan County will help determine how the $100 million in CFFD funds will be allocated.

707. In addition to the above, our Decision sets forth numerous rulings that carefully balance the competing interests of numerous intervenors and provide the necessary clarity for an efficient and transparent Phase II process. Some of these rulings include the following:

a. We maintain our initial approach and defer granting an unconditional CPCN for the MVLE until a showing in Phase II that a portfolio including the cost of the MVLE and any related transmission investment in southeast Colorado is in the public interest.

b. We establish a suite of Phase II portfolios that Public Service must model. These Phase II portfolios are intended to provide a wide range of potential pathways, including accelerated emissions reduction portfolios, portfolios with limited amounts of new gas-fired resources, least cost portfolios, and a business as usual portfolio.

c. We largely approve the Company's request for a conforming bid policy and provide guidance and a process to help the parties achieve further agreement on a non-negotiable PPA.

d. We address several Phase II modeling methodologies, such as the best-in-class process, assumptions regarding existing and planned thermal units, and updates to the generic prices of resources.

e. We deny the Company's proposal to use an SRR penalty in the Phase II modeling based on evidence that it would inappropriately discourage the model from selecting solar resources in the Pueblo area.

f. We largely adopt Staff's tariff passthrough proposal that will encourage bidders to participate in the resource solicitation process in the face of substantial uncertainty regarding future tariff impacts.

g. We adopt the Company's BVEM proposals, including for a labor economist to calculate a BVEM score for each Phase II portfolio and direct Public Service to ensure that provision and presentation of BVEM rules during Phase II of this Proceeding (both the base RFP and supplemental RFP) fully comply with the statutory requirements.

708. Through these and many other rulings, this Decision provides the necessary regulatory certainty for Public Service to move to Phase II in which the Company will solicit and evaluate various bids for new generation and storage resources. Consistent with this Decision, Public Service will compile these bids into various Phase II portfolios and ultimately present its plan for acquiring additional resources in the 120-Day Report.

II. ORDER

A. The Commission Orders That:

1. The Verified Application for Approval of a 2024 Just Transition Solicitation filed by Public Service Company of Colorado ("Public Service") on October 15, 2025, is granted, with modifications, consistent with the discussion above.

2. The Omnibus Motion for Extraordinary Protection of Highly Confidential Information, and for Partial Waiver of Rules 3606(b), 3612(a), 3618(b)(I), 3613(a) and 3613(d) and Waiver of Rule 3608(c)(III)-(IV) filed by Public Service on October 15, 2025, is granted, in part, and denied, in part, consistent with the discussion above. The requested waivers of

Commission Rules 3606(b), 3612(a), 3618(b)(I), 3613(a), 3613(d), 3613(e)-(h) are denied. The requested waiver of Rules 3608(c)(III)-(IV) is granted.

3. The Motion to Strike filed on August 4, 2025, by Moffat County and the City of Craig is denied.

4. The 20-day period provided for in § 40-6-114, C.R.S., within which to file applications for rehearing, reargument, or reconsideration, begins on the first day following the effective date of this Decision.

5. This Decision is effective upon its Issued Date.

B. ADOPTED IN COMMISSIONERS' DELIBERATIONS AND WEEKLY MEETINGS
August 6, 13, 18, 21, and 27, 2025.

(S E A L)

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

ERIC BLANK

MEGAN M. GILMAN

ATTEST: A TRUE COPY

TOM PLANT

Commissioners

Rebecca E. White,
Director

COMMISSIONERS ERIC BLANK,
MEGAN M. GILMAN, AND
TOM PLANT, DISSENTING,
IN PART

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	)	Order No. 202-26-21

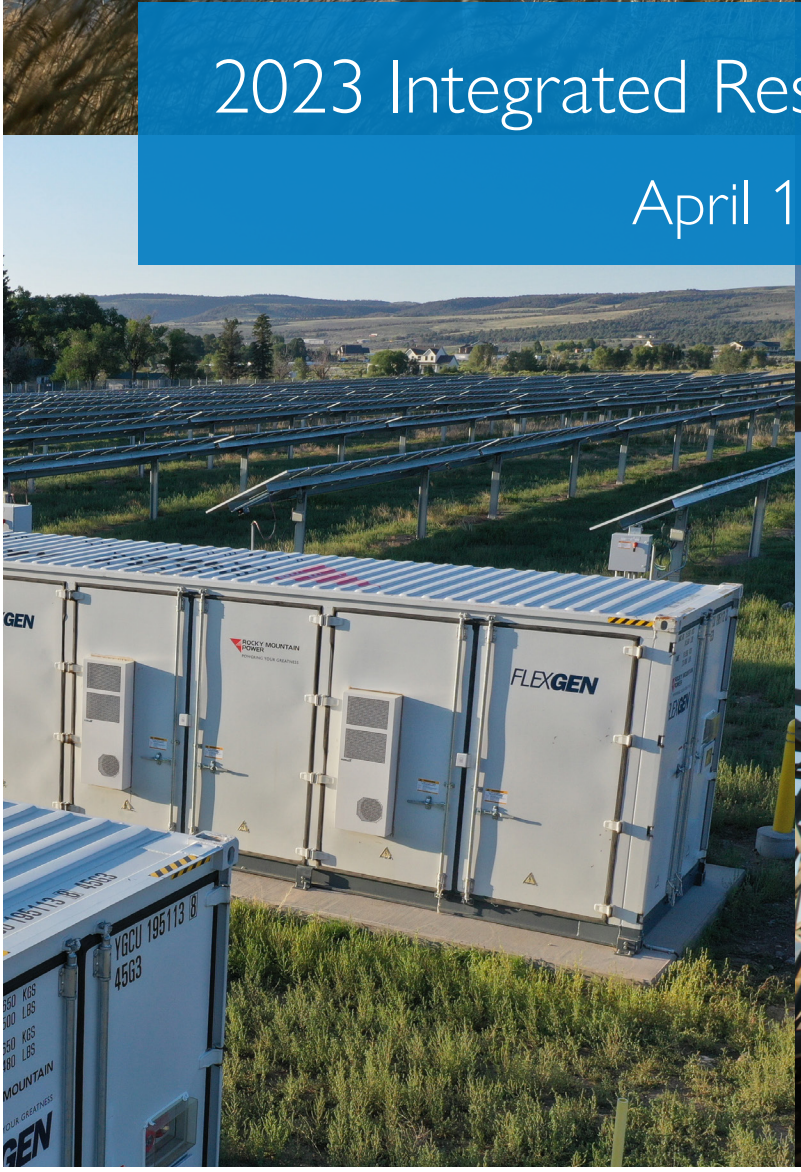
Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-98:
PacifiCorp 2023 IRP Update

2023 Integrated Resource Plan Update

April 1, 2024



PacifiCorp®

This 2023 Integrated Resource Plan Update is based upon the best available information at the time of preparation. The IRP action plan status update described herein is subject to change as new information becomes available or as circumstances change. It is PacifiCorp's intention to revisit and refresh the IRP action plan no less frequently than annually.

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FIGURE 6.32 – INCREASE/(DECREASE) IN SYSTEM COST ASSUMING WASHINGTON 110

CHAPTER 1 – EXECUTIVE SUMMARY

PacifiCorp submitted its Amended Final 2023 Integrated Resource Plan (IRP) on May 31, 2023. That plan provides a framework for future actions PacifiCorp will take to provide reliable and valuable electric service for customers with a least-cost, least-risk resource portfolio. The 2023 IRP Update reflects resource planning and procurement activities since the 2023 IRP, presents an updated load-and-resource balance, and an updated resource portfolio consistent with changes in the planning environment. The 2023 IRP Update also provides a status update for the action plan filed with the 2023 IRP. In presenting the updated load-and-resource balance and updated resource portfolio, PacifiCorp highlights changes in the 2023 IRP Update preferred portfolio[1] relative to the 2023 IRP preferred portfolio, which covers the 2024 to 2042 planning horizon. Consistent with the 2023 IRP, the 2023 IRP Update's preferred portfolio demonstrates reliable service will require investment in transmission infrastructure, new wind and solar resources, the conversion of two coal units to natural gas peaking units, growth in demand response and energy efficiency programs, the addition of carbon capture technology on identified coal resources, the addition of an advanced nuclear resource, the addition of energy storage resources, and the addition of natural gas peaking resources that are capable of converting to non-emitting fuels. The 2023 IRP Update preferred portfolio includes resources necessary for individual state policy compliance and assumes those resources are allocated to the state whose policy necessitated the addition.

Key changes in this 2023 IRP Update are driven by U.S. Environmental Protection Agency's (EPA) approval of Wyoming's state Ozone Transport Rule (OTR) plan, the stay of EPA's disapproval of Utah's state OTR plan, extensions to the assumed operational life of new natural gas generating resources, energy storage acquisition strategy, forecast load demand, higher coal prices, and natural gas and wholesale power market price updates.

In addition, PacifiCorp has advanced its modeling strategy to address regulatory and stakeholder feedback, using a robust iterative process to refine the optimization process. For example, the 2023 IRP Update preferred portfolio includes system-allocated resources as well as resources that are needed to meet the requirements of specific states. Resources needed to meet specific state policy compliance requirements may need to be assigned, in their entirety, to a single state to avoid adding unnecessary cost burdens to customers in other states, which could raise other potential issues related to operations and resource adequacy that have not been addressed in the system approach of the 2023 IRP Update preferred portfolio. Future allocations of any incremental costs associated with both system resources and resources included in the plan solely to meet state-specific policy objectives will need to be addressed to ensure alignment of costs and benefits.

Customer Focus

At PacifiCorp, we're committed to meeting the demands of our customers and communities throughout the West to deliver safe, affordable, reliable energy and a resilient, modern grid. Our integrated system connects and brings new opportunities to the West, building on a foundation of infrastructure designed to handle extreme weather and enhance the energy resilience of communities from the Pacific Coast to the Rocky Mountains, all while continuing to deliver valuable energy solutions for our customers at prices that are below national and regional averages.

[1] The preferred portfolio is the least-cost, least-risk resource plan over the 20-year IRP study horizon.

Together with the communities we serve and our regional partners, it is time to act, with targeted, strategic investments that will position us to continue delivering safe, valuable, reliable power to our customers.

Our customer-centered vision embodies four core themes:

Reliable Power: We strive to deliver energy safely during all hours, and plan extensively to ensure that we have sufficient supply and the ability to deliver to the communities we serve. We understand that electricity is an essential service, and work around the clock to ensure that we are dependable, and that our communities can rely on us.

Resilient Infrastructure: We live in times of rapid change, with more extreme weather and challenging conditions. We are working to minimize disruptions, implement strategies to recover quickly when they occur, and deploy upgrades that will strengthen our critical infrastructure.

Valuable Service: PacifiCorp is proud to be one of the lowest-cost electricity providers in the nation and the region and we are committed to continue doing so as we make new and much needed investments in generation and transmission infrastructure. As we plan for new resources, we are prioritizing actions that are necessary to support customer needs and the reliability of the system while reflecting the policy values of each of our states at the lowest cost possible.

Clean Energy: Through strategic, customer-focused investments in diverse resources, PacifiCorp's plan continues to show a reduction in carbon emissions. The 2023 IRP Update preferred portfolio indicates that carbon emissions will decrease by more than 60% from 2005 levels by 2030. Although a higher load forecast and the removal of OTR compliance requirements has extended our emissions reduction timeline in comparison to the 2023 IRP, the 2023 IRP Update resource plan continues to include significant new renewable additions among other diverse, advanced technologies. This path of renewables additions and advanced technologies achieves even deeper decarbonization beyond 2030.

2023 IRP Update Roadmap

We're advancing our critical infrastructure to meet the challenges of a rapidly changing economy, while laying the groundwork for long-term value and reliability through building a more resilient grid.

The 2023 IRP Update preferred portfolio includes:

- Resources
    - 9,818 megawatts of new wind resources (including 443 megawatts for Washington and 239 megawatts of small-sale wind for Oregon).
    - 4,016 megawatts of storage resources, including batteries collocated with solar generation, standalone batteries, and pumped hydro storage resources (including 101 megawatts of standalone batteries for Oregon and Washington).

  - 3,763 megawatts of new solar resources, mostly paired with battery storage, (including 483 megawatts of small-scale solar for Oregon).
  - 4,326 megawatts of capacity saved through energy efficiency programs.
  - 1,123 megawatts of capacity saved through demand response programs.
  - 500 megawatts of advanced nuclear (Natrium™ reactor demonstration project) in 2030.
  - 5,385 megawatts of natural gas convertible peaking resources that meet high-demand energy needs (including 224 megawatts of renewable-fueled peaking resources for Oregon).
  - Installation of carbon capture technology on Jim Bridger Units 3 and 4.
- Transmission
  - As supported by needs established in previous IRPs, PacifiCorp is finalizing construction of the Energy Gateway South and Energy Gateway West Sub-Segment D1 transmission projects and partnering with Idaho Power to build the Energy Gateway Sub-Segment H (Boardman-to-Hemingway or B2H) transmission project.
  - Additional transmission upgrades to increase transfer capability and/or enable renewable resource requests to connect to the transmission system in southeast Idaho, central and northern Utah, eastern Wyoming, throughout Oregon, and in Yakima and Walla Walla, Washington. Approximately two gigawatts of additional interconnection capacity are added through 2032, in addition to the amounts directly associated with Energy Gateway South, Energy Gateway West Sub-Segment D1, and B2H.

PacifiCorp's Integrated Resource Plan Approach

In the 2023 IRP Update, PacifiCorp presents a preferred portfolio that builds on its vision to deliver valuable energy service, reliably, and responsibly. We are achieving this vision while meeting our customers' growing energy needs through near-term investments in transmission infrastructure and continued growth in new generation and storage resource capacity as well as maintaining substantial investment in energy efficiency and demand response programs.

The primary objective of the IRP is to identify the best mix of resources to serve customers in the future. The best combination of resources is determined through analysis that measures cost and risk. The least-cost, least-risk resource portfolio—defined as the "preferred portfolio"—is the portfolio that can be delivered through specific action items at a reasonable cost and with manageable risks while delivering reliable service to customers and ensuring compliance with state and federal regulatory obligations without cost-shifting amongst states for compliance.

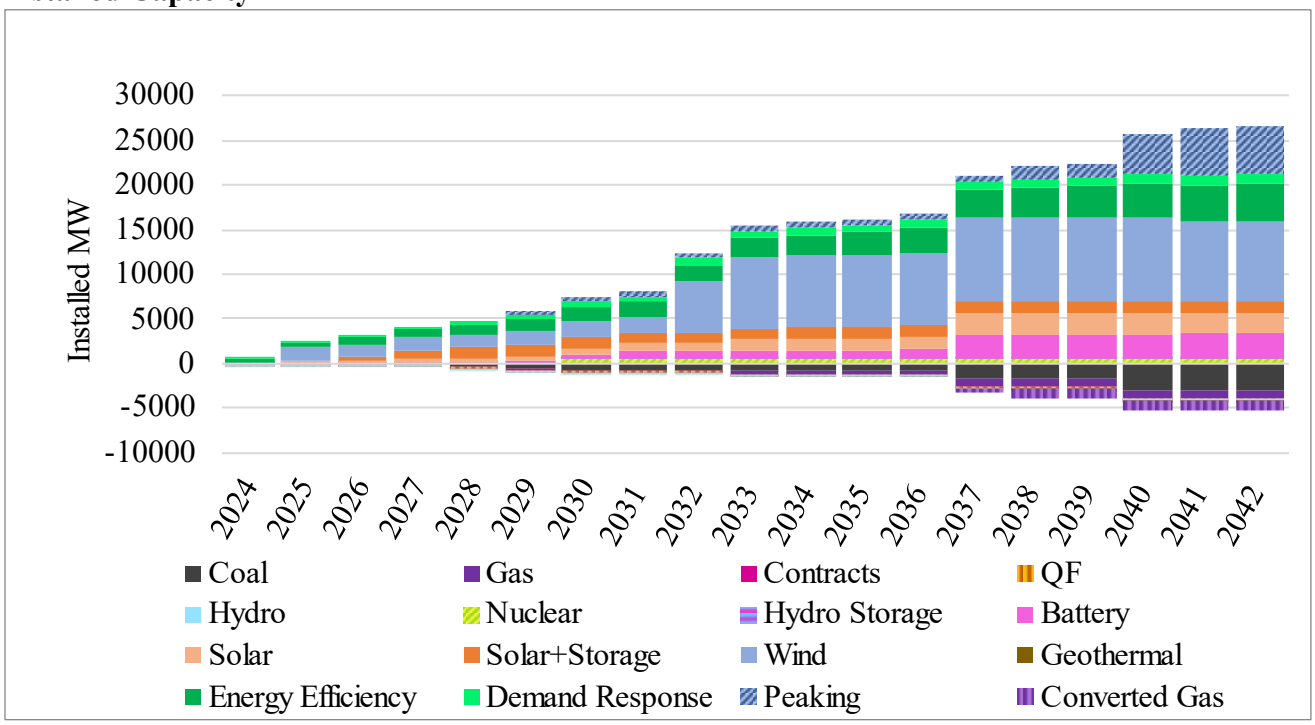
The full planning process is completed every two years, with a review and update completed in the off years. Consequently, these plans, particularly the longer-range elements, can and do change over time.

Figure 1.1 – Key Elements of PacifiCorp's 2023 IRP Update Approach

2023 IRP Update Preferred Portfolio Highlights

PacifiCorp's selection of the 2023 IRP Update preferred portfolio is supported by comprehensive data analysis, described in the chapters that follow. Figure 1.2 shows that PacifiCorp's 2023 IRP Update preferred portfolio continues to include substantial new renewables facilitated by incremental transmission investments, along with demand-side management (DSM) resources, significant storage resources, Natrium™ advanced nuclear, and dispatchable peaking resources. A more detailed summary of preferred portfolio resources by resource type is presented later in this section.

Figure 1.2 – 2023 IRP Update All-State Preferred Portfolio Cumulative Changes in Installed Capacity



*Note: "Coal" includes both minority and majority owned coal resources, including Jim Bridgers 3 & 4 with carbon capture technology. "Coal" does not include coal resources converted to gas. Coal resources converted to gas are categorized under "Converted Gas" and are only shown at retirement, as the conversion does not increase the installed capacity of the resource. "Gas" includes only existing gas resources. New gas peaking and new hydrogen peaking resources are grouped under "Peaking". "Nuclear" includes only the Natrium™ advanced nuclear project.

Transmission Upgrades

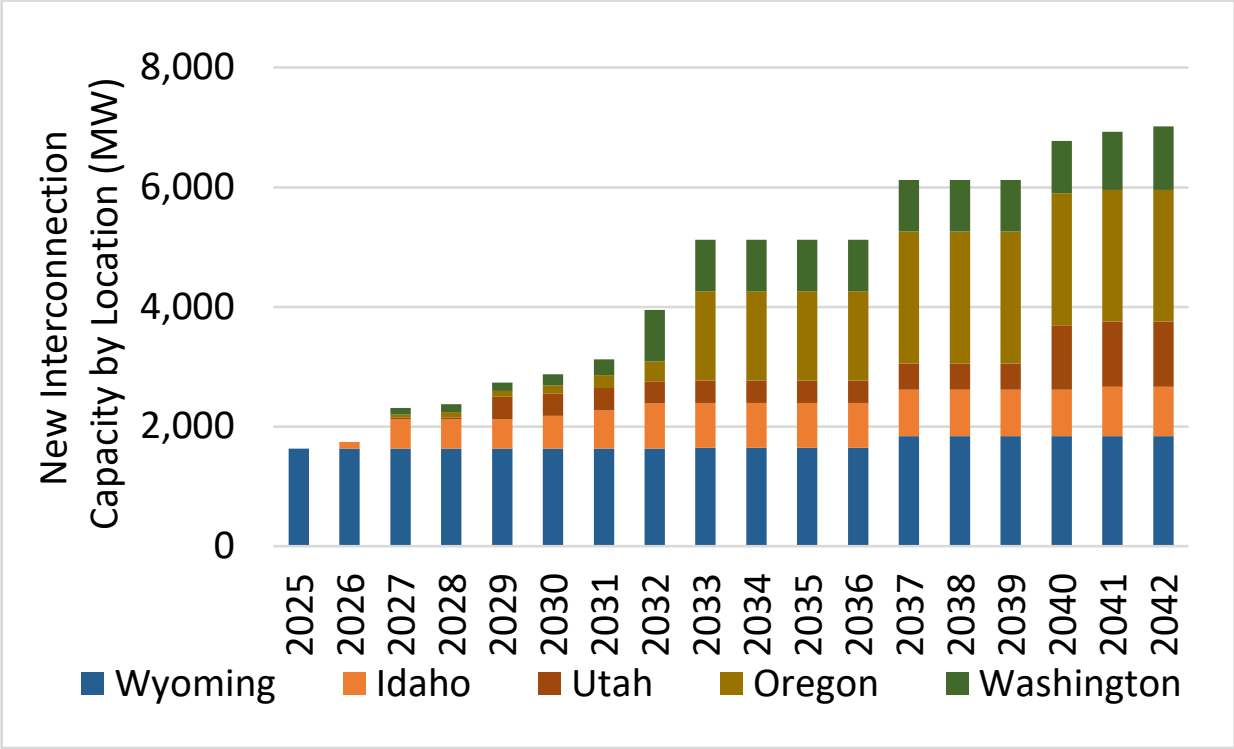
To facilitate the delivery of new resources to PacifiCorp customers across the West, the 2023 IRP Update preferred portfolio includes additional transmission investment. As supported by needs established in previous IRPs, PacifiCorp is finalizing construction of the Energy Gateway South and Energy Gateway West Sub-Segment D1 transmission projects and partnering with Idaho Power to build the B2H transmission project, which is expected to come online in the 2026-2027 timeframe. B2H is a 290-mile high-voltage 500 kilovolt transmission line that connects the Longhorn substation near the town of Boardman in Oregon to the Hemingway substation in Idaho. By exchanging certain transmission assets with Idaho Power Company, PacifiCorp will receive additional transmission rights between Hemingway and the Populus substation in Idaho, which is closely tied to existing and future PacifiCorp transmission connecting to Utah and Wyoming. At the Oregon end of the B2H line, additional transmission upgrades are planned to connect B2H to growing loads.

In the 2023 IRP Update, many transmission upgrades and the accompanying resources reflect the results of PacifiCorp's generator interconnection "cluster study" process for evaluating proposed resource additions. By evaluating all newly proposed resource additions in an area at the same time, the cluster study process identifies collective solutions that can allow projects that are ready to move forward to do so in a timely fashion. As a result, transmission upgrades and resource additions in the 2023 IRP Update preferred portfolio consider cluster study requests submitted in the past several years. Figure 1.3 summarizes the new interconnection capacity selected to facilitate new generation resources identified as part of the 2023 IRP Update preferred portfolio.

In addition to providing increased interconnection capacity, transmission upgrades are also expected to allow for increased transfer capability between different areas of PacifiCorp's system. The 2023 IRP Update preferred portfolio includes portions of the following transmission upgrades between the following areas within the IRP topology. Note that modeling for the 2023 IRP Update allowed for partial selection of lines, though that does not indicate that these lines would be uneconomic if built in their entirety. Given the timing identified primarily in the second half of the IRP study horizon, these opportunities will continue to be explored in the future.

- Walla Walla to Yakima.
- Gateway Sub-Segment D3: provides direct transfers between Jim Bridger and Borah (Populus), but with supporting projects, also facilitates transfers between Wyoming East and Jim Bridger and between Borah and Utah North.
- Incremental Gateway Segments: Segments D2.2, D1.2, and Gateway South 2 would be the second iteration of existing or soon to be in service segments from the original Gateway plan, and would provide additional transfer capability between Wyoming East and Bridger and between Wyoming East and Clover.
- Oregon 500 kilovolt upgrades: several 500 kilovolt upgrades and supporting projects would connect Portland-North Coast, Willamette Valley, Southern Oregon, and Central Oregon.
- East-West transfers: together, B2H 2 and Gateway Segment E would further increase transfer capability between PacifiCorp's east and west balancing authority areas.

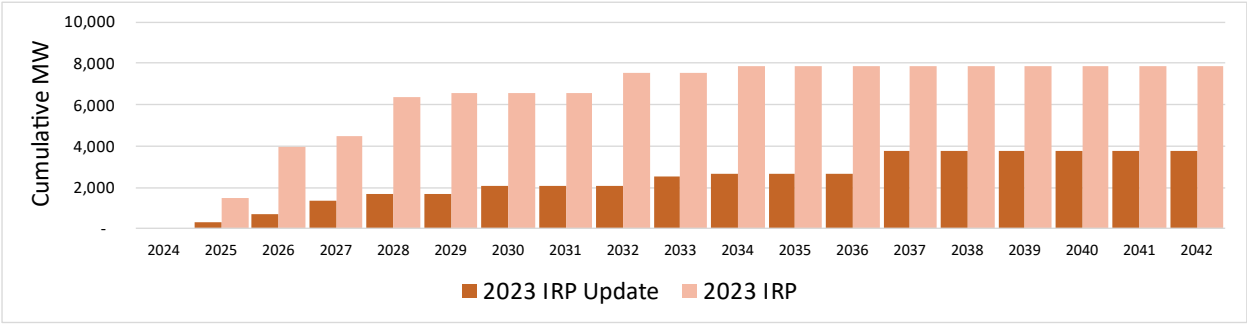
Figure 1.3 – New Interconnection Capacity by Location



New Solar Resources

The 2023 IRP Update preferred portfolio includes 2,084 megawatts of solar by the end of 2030, and 3,749 megawatts of new solar is online by 2037, as shown in Figure 1.4 While not shown in Figure 1.4, the company has previously contracted for one gigawatt of solar resources with commercial operation dates between 2024 and 2026 for customer-directed voluntary renewable procurement programs.

Figure 1.4 – 2023 IRP Update Preferred Portfolio New Solar Capacity*

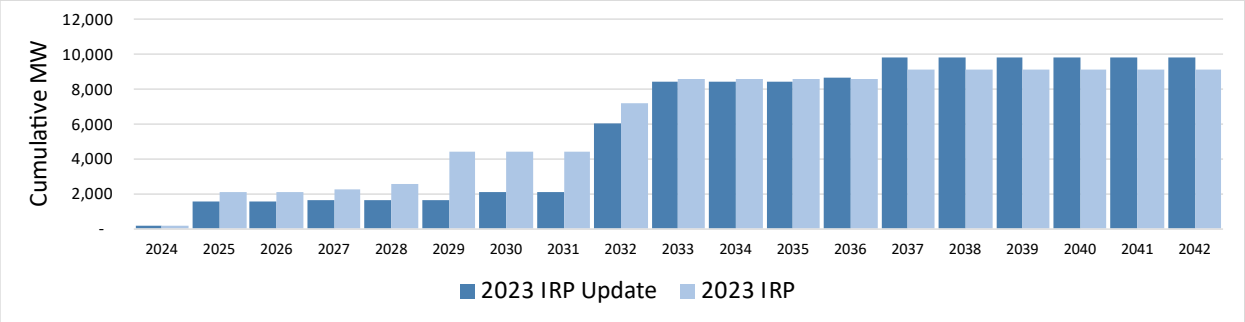


* 2023 IRP Update solar capacity shown in the figure includes committed solar resources shown in 2025 and 2026. Resources are shown in the first full year of operation (the year after the year-online dates). This total includes 374 megawatts of small scale solar to meet Oregon requirements.

New Wind Resources

As shown in Figure 1.5, by 2032, PacifiCorp's 2023 IRP Update preferred portfolio includes 6,034 megawatts of new wind resources, and more than 9,800 megawatts of new wind resources by 2037.

Figure 1.5 – 2023 IRP Update Preferred Portfolio New Wind Capacity*

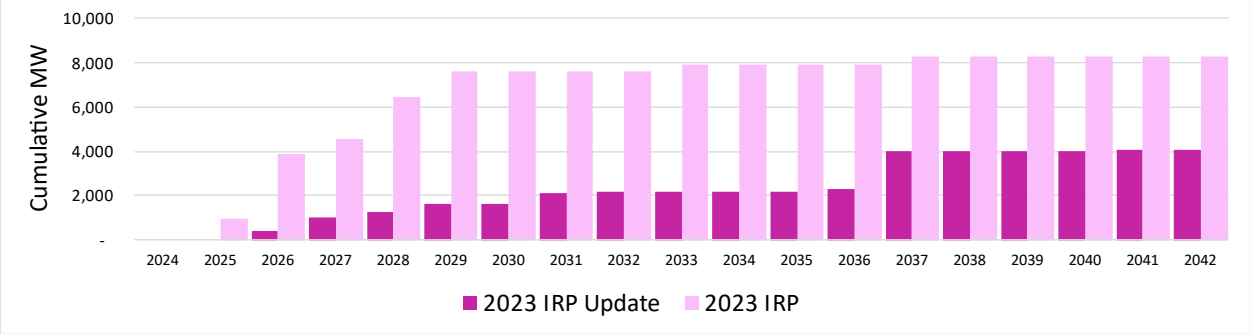


*Note: Wind additions shown are incremental to Energy Vision 2020 and other projects that have come online over the past few years. Resources are shown in the first full year of operation (the year after year-end online dates). This figure includes 254 megawatts of small-scale wind to meet Oregon requirements, and an additional 443 megawatts of utility scale wind to meet Washington requirements.

New Storage Resources

As shown in Figure 1.6, the 2023 IRP Update preferred portfolio includes 1,626 megawatts of new storage capacity by the end of year 2029 and more than 4,000 megawatts by 2037.

Figure 1.6 – 2023 IRP Update Preferred Portfolio New Storage Capacity*

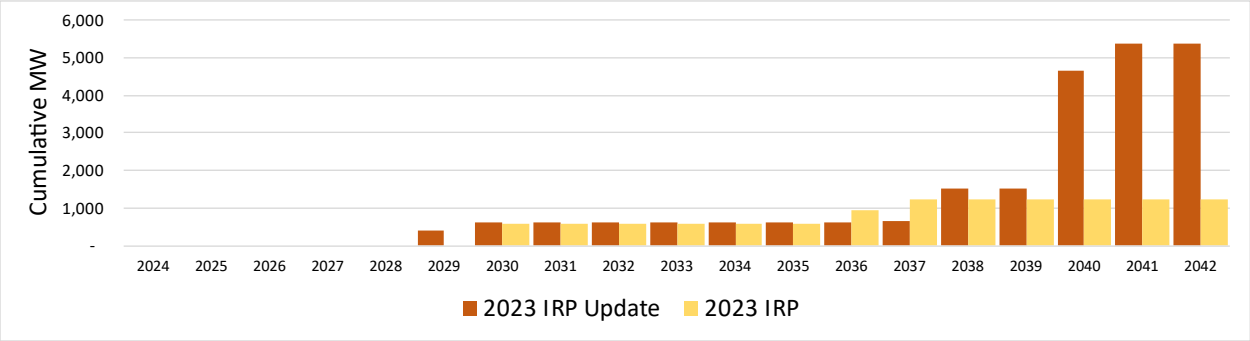


*Note: Resources are shown in the first full year of operation (the year after the year-end online dates). This figure includes a total of 101 megawatts of storage resources required for Oregon and Washington for compliance.

Peaking Capacity

The 2023 IRP Update continues to indicate the need for flexible peaking capacity to achieve reliability and minimize risk. A key change since the filing of the 2023 IRP is the addition of peaking capacity in the form of natural gas resources capable of operating with 100% hydrogen fuel. The inclusion of this technology also guards against the future risk of increasingly constrained emissions and future policy requirements.

Figure 1.7 – 2023 IRP Update Preferred Portfolio Peaking Resources Capacity*

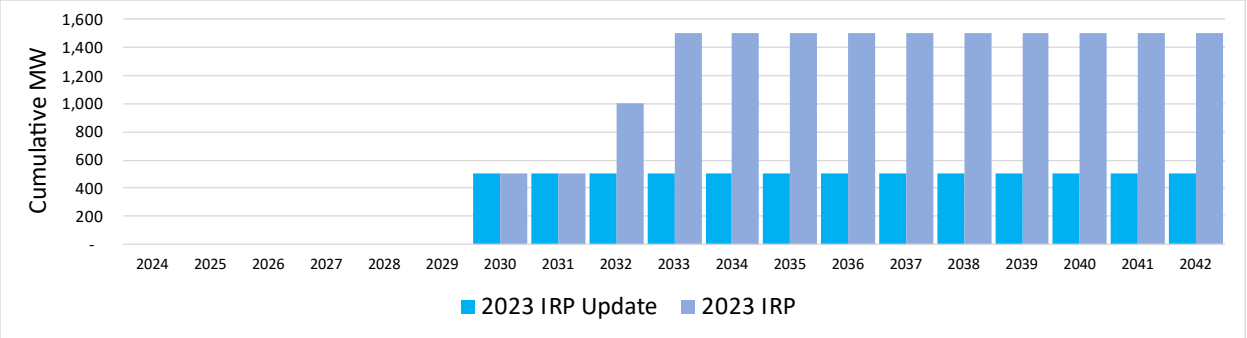


*Note: Resources are shown in the first full year of operation (the year after the year-end online dates). This figure includes 224 megawatts of peaking units for Oregon compliance that can only run on renewable fuel.

Nuclear Capacity

The 2023 IRP Update continues to show the value associated with the Natrium™ Demonstration Project which provides a significant non-emitting resource. A key change since the filing of the 2023 IRP is the stay of the EPA's disapproval of Utah's OTR plan and subsequent ability of the existing thermal fleet to operate with fewer restrictions as a dispatchable resource. Although additional advanced nuclear resources beyond the Natrium™ Demonstration Project are not selected in this update, PacifiCorp is continually updating advanced nuclear resource cost estimates as they become available.

Figure 1.8 – 2023 IRP Update Preferred Portfolio New Nuclear Capacity*



*Note: Resources are shown in the first full year of operation (the year after the year-end online dates).

Demand-Side Management

PacifiCorp evaluates new DSM opportunities, which includes both energy efficiency and demand response programs, as a resource that competes with traditional new generation and wholesale power market purchases when developing resource portfolios for the IRP. The optimal determination of DSM resources results in selecting all cost-effective DSM as a core function of IRP modeling. Consequently, the load forecast used as an input to the IRP does not reflect any incremental investment in new energy efficiency programs; rather, the load forecast is reduced by the selected additions of energy efficiency resources in the IRP Update.

Figure 1.9 indicates that PacifiCorp's load forecast before incremental energy efficiency savings has decreased over the 2024 to 2027 timeframe and increased from 2028 and on relative to projected loads used in the 2023 IRP. In the near term, lower projected demand from data centers results in a lower forecast, while data center expectations over the long-term result in a higher forecast. On average, the forecasted system load is up 0.8% and the forecasted coincident system peak is up 1.2% over the 20-year planning horizon when compared to the 2023 IRP. Over the 2024 to 2042 timeframe, the average annual growth rate, before accounting for incremental energy efficiency improvements, is 2.13% for load and 1.80% for peak.

Figure 1.9 – Forecasted Annual Load (Before Incremental Energy Efficiency Savings)

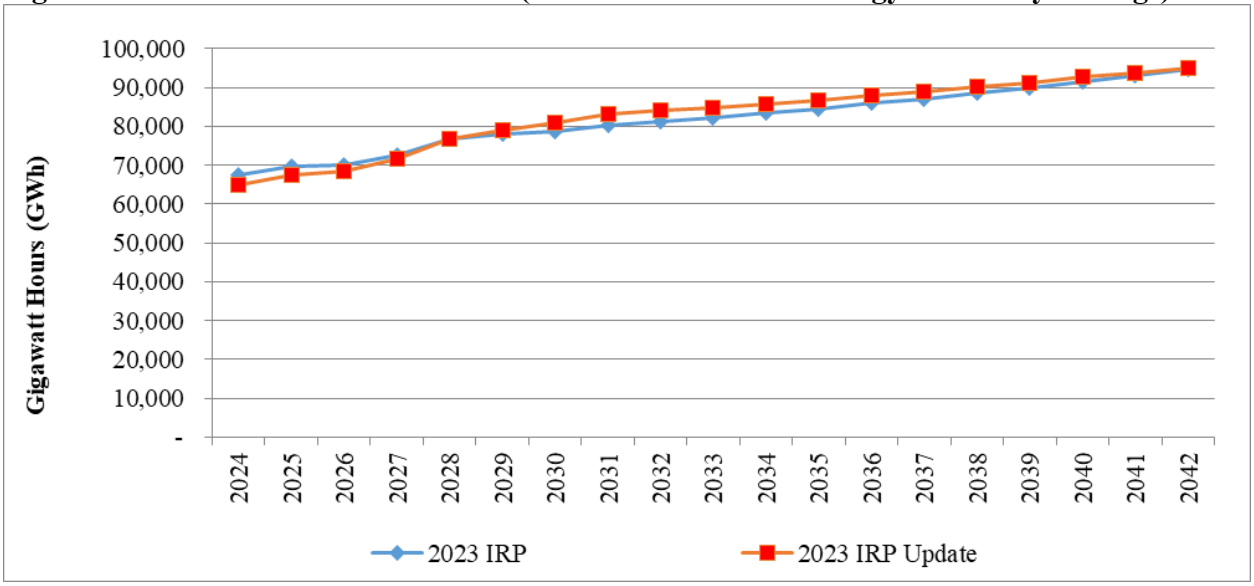
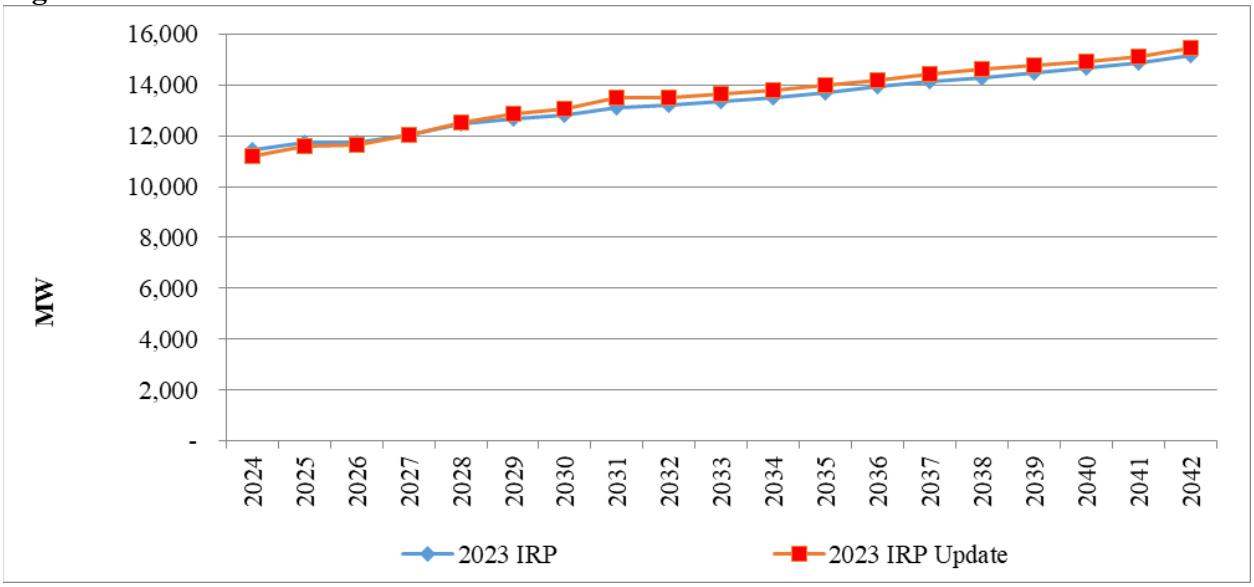


Figure 1.10 – Forecasted Annual Coincident Peak Load

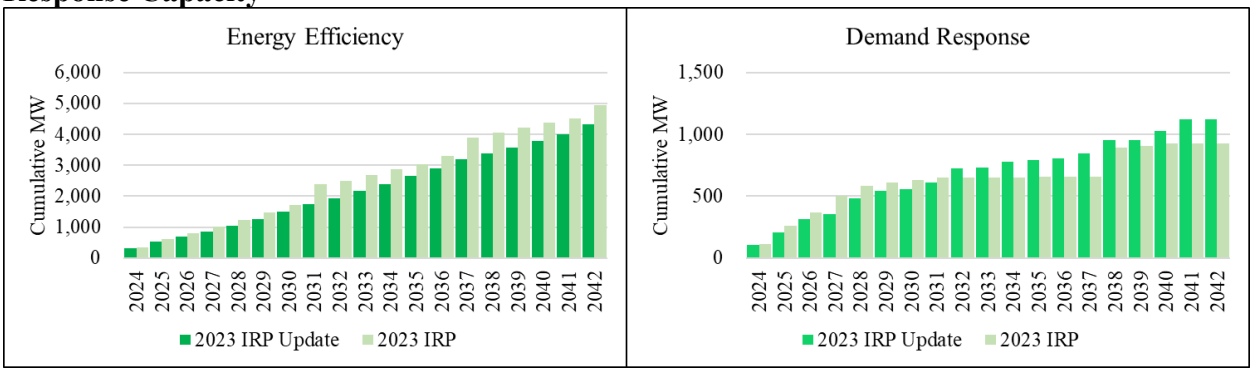


DSM resources continue to play a key role in PacifiCorp's resource mix. The chart to the left in Figure 1.11 compares total energy efficiency capacity savings in the 2023 IRP Update preferred

portfolio relative to the 2023 IRP preferred portfolio and includes 4,326 megawatts by the end of the planning period.

In addition to continued investment in energy efficiency programs, the preferred portfolio shows a need for incremental demand response programs. The chart to the right in Figure 1.11 compares cumulative demand response program capacity in the 2023 IRP Update preferred portfolio relative to the 2023 IRP preferred portfolio and does not include capacity from existing programs. The 2023 IRP Update has a cumulative capacity of incremental demand response programs reaching 1,123 megawatts by 2042 which represents a 21% increase relative to the 2023 IRP.

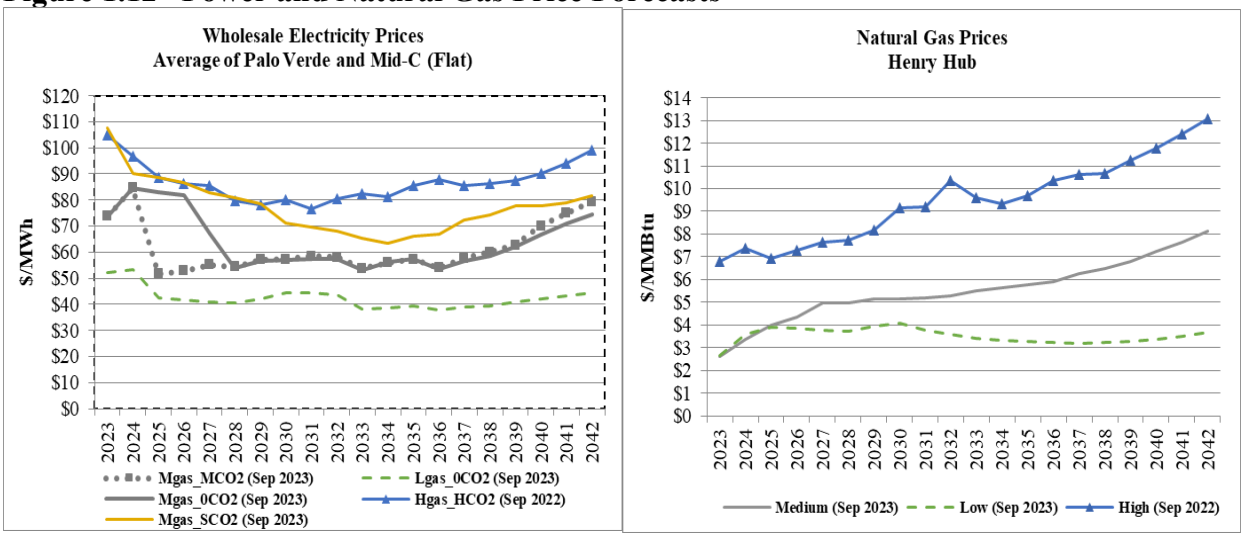
Figure 1.11 – 2023 IRP Update Preferred Portfolio Energy Efficiency and Demand Response Capacity



Wholesale Power Market Prices and Market Activity

Figure 1.12 illustrates the electricity and natural gas price forecasts used in the 2023 IRP Update. These forecasts are based on prices observed in the forward market and on projections from third-party experts.

Figure 1.12 –Power and Natural Gas Price Forecasts



Subsequent to the filing of the 2023 IRP, the EPA's approval of Wyoming's state OTR plan and the stay of EPA's disapproval of Utah's state OTR plan removed the restrictions that limit energy

production in the summer from natural gas and coal-fueled resources in Wyoming and Utah. In the absence of the OTR driver, market purchases can cost-effectively replace some of the incremental renewable resources that were indicated in the 2023 IRP preferred portfolio, leading to higher relative market activity, as shown in Figure 1.13 and Figure 1.14 below. In addition, a 500 megawatt capacity Wyoming market has been added in the 2023 IRP update, representing the ongoing ability to access diverse (and potentially new) regional markets as discussed in Chapter 3.

Figure 1.13 – 2023 IRP Update Preferred Portfolio Summer Market Purchases

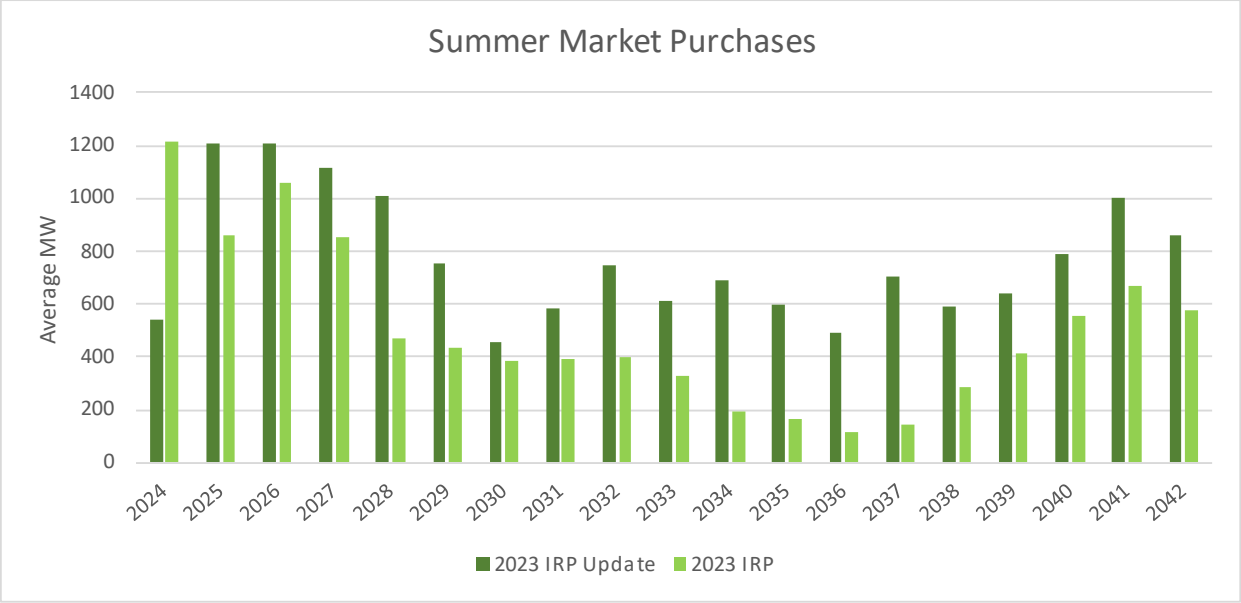
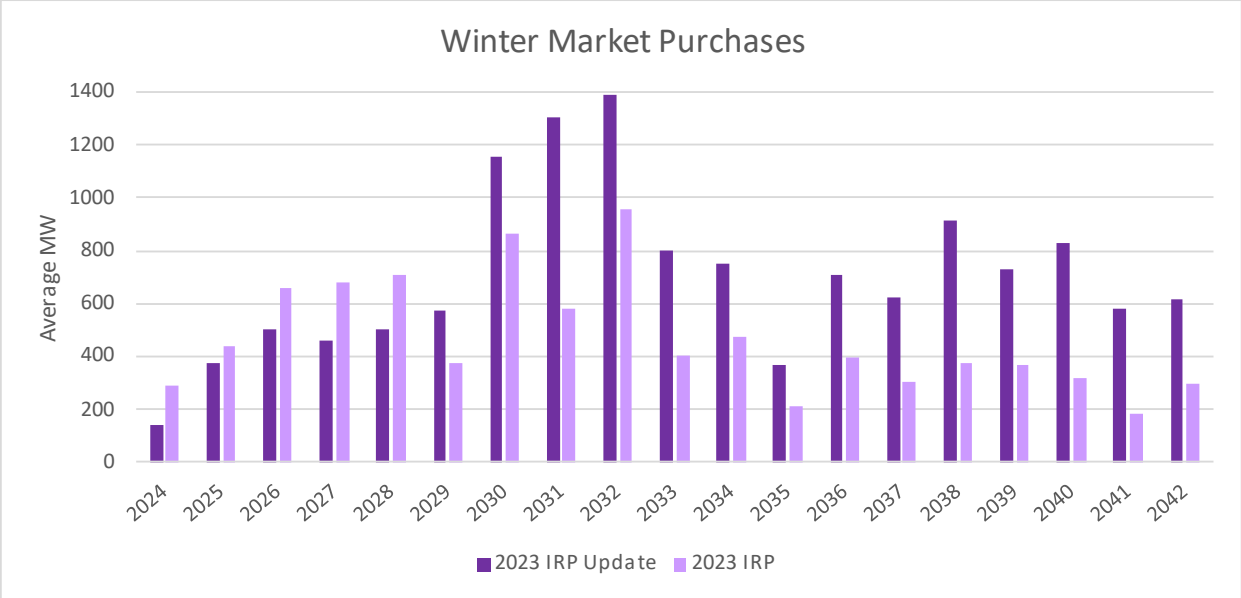


Figure 1.14 – 2023 IRP Update Preferred Portfolio Summer Market Purchases



*Note: "Summer Market Purchases" includes purchases from June through September while "Winter Market Purchases" includes purchases from December and January. While most data for tables and figures in this document comes from LT capacity expansion model results, this figure uses ST model results. For market data, it is appropriate

to use ST model results because the ST model is run with an hourly granularity which more accurately represents the energy needed to meet load obligations compared to the less granular LT capacity expansion model.

Coal and Gas Retirements/Gas Conversions

Coal resources have been an important resource in PacifiCorp's resource portfolio for many years. The operating capabilities of these facilities have been able to adapt to changes in the planning environment. For example, PacifiCorp has been able to lower operating minimums and optimize coal dispatch through the Western Energy Imbalance Market (WEIM or EIM). This in turn has enabled the company to both reduce fuel consumption and associated costs and emissions by increasingly buying low-cost, zero-emissions renewable energy from market participants across the West, which is accessed by our expansive transmission grid. PacifiCorp's coal resources will continue to play a pivotal role in following fluctuations in renewable energy as the remaining coal units approach retirement dates. EPA's approval of Wyoming's ozone plan and the stay of EPA's disapproval of Utah's ozone plan results in fewer restrictions on coal-fired operation than were assumed in the 2023 IRP. With these updates, Utah coal resources are no longer planned to retire early, as shown in Table 1.1 Hunter and Huntington coal unit retirements, specifically, have returned to the schedule that had been previously indicated by PacifiCorp's 2021 IRP.

Table 1.1 – Coal Unit Retirements in the 2023 IRP and 2023 IRP Update

Coal			
Unit	2023 IRP Retirement Year (12/31/__)	2023 IRP Update Retirement Year (12/31/__)	Delta to 2023 IRP (Years)
	As Selected	As Selected	
Colstrip 3	2025	2025	-
Colstrip 4	2029	2029	-
Craig 1	2025	2025	-
Craig 2	2028	2028	-
DaveJohnston 1	2028	2028	-
DaveJohnston 2	2028	2028	-
DaveJohnston 3	2027	2027	-
DaveJohnston 4	2039	2039	-
Hayden 1	2028	2028	-
Hayden 2	2027	2027	-
Hunter 1	2031	2042	11
Hunter 2	2032	2042	10
Hunter 3	2032	2042	10
Huntington 1	2032	2036	4
Huntington 2	2032	2036	4
JimBridger 1	2037	2037	-
JimBridger 2	2037	2037	-
JimBridger 3	2037	2039	2
JimBridger 4	2037	2039	2
Naughton 1	2036	2036	-
Naughton 2	2036	2036	-
Wyodak	2039	2039	-

Coal unit exits, retirements, gas conversions, and retrofits scheduled under the preferred portfolio include:

- 2023 = Jim Bridger Units 1-2, converted to natural gas in 2024 (same as in the 2023 IRP)
- 2025 = Craig Unit 1 retirement (same as in the 2023 IRP)
- 2026 = Naughton Units 1-2, converted to natural gas in 2026, operates through 2036 (same as in the 2023 IRP)
- 2027 = Dave Johnston Unit 3 retirement (same as in the 2023 IRP)
- 2027 = Hayden Unit 2 retirement (same as in the 2023 IRP)

- 2028 = Jim Bridger Units 3-4, retrofitted with carbon capture technology in 2028, operates through 2039 (converted to gas conversion in 2030 and retired in 2037 in the 2023 IRP; unit life is extended by 2 years to capture 12 full years of investment tax credits)
- 2028 = Dave Johnston Units 1-2 retirement (same as in the 2023 IRP)
- 2028 = Craig Unit 2 retirement (same as in the 2023 IRP)
- 2028 = Hayden Unit 1 retirement (same as in the 2023 IRP)
- 2029 = Colstrip Unit 4 exit, Colstrip Unit 3 share is consolidated into Colstrip Unit 4 in 2025 (same as in the 2023 IRP)
- 2036 = Huntington Units 1-2 retirement, no emissions controls (SNCR installation in 2026, operating through 2032 in the 2023 IRP)
- 2039 = Dave Johnston Unit 4 retirement (same as in 2023 IRP)
- 2039 = Wyodak retirement, no emissions controls (SNCR installation in 2026, operating through 2039 in the 2023 IRP)
- 2042 = Hunter Units 1-3 retirement, no emissions controls (SNCR installation in 2026, operating through 2031 and 2032 in the 2023 IRP)

Resource Procurement and Requests for Proposals

As evaluated in the 2023 IRP, the OTR significantly restricted energy production in the summer among natural gas and coal-fueled resources in Wyoming and Utah, which triggered a need for incremental resources. EPA's approval of Wyoming's state OTR plan and the stay of EPA's disapproval of Utah's state OTR plan removes the restrictions that limit energy production in the summer from natural gas and coal-fueled resources in Wyoming and Utah. The 2023 IRP Update preferred portfolio demonstrates that with limited procurement of battery resources in the near-term, which can be achieved outside of a request for proposals process, there is a material benefit to scaling down and delaying resource acquisition until after 2030. This outcome supports the company's decision to suspend the 2022 All-Source Request for Proposals, which will be terminated. The proposed small-scale renewable request for proposal will not be issued until additional stakeholder outreach can be completed. The 2025 IRP will inform the next steps for incremental resource acquisition.

Carbon Dioxide Emissions

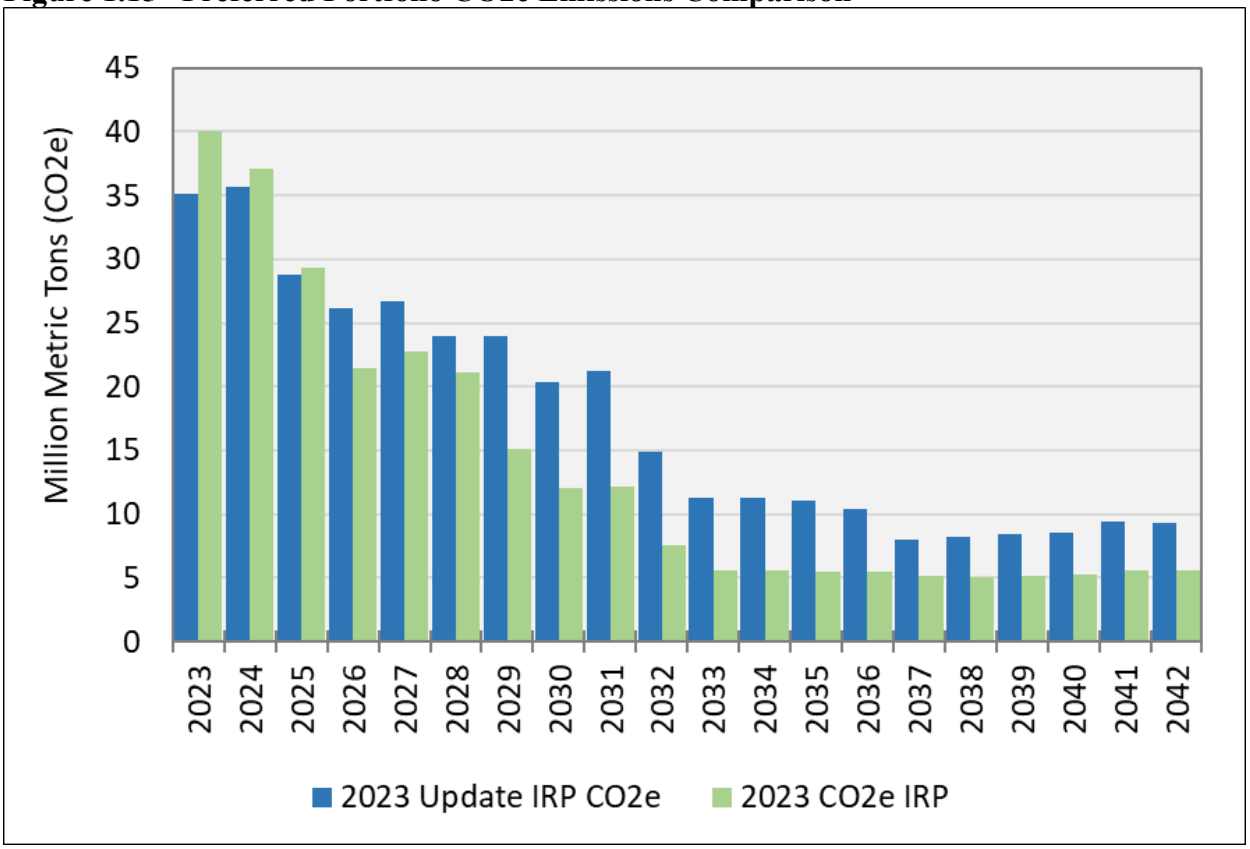
The 2023 IRP Update preferred portfolio reflects PacifiCorp's on-going efforts to provide valuable energy solutions for our customers that reflects a continued trajectory of declining carbon dioxide (CO_2) and other carbon dioxide equivalent (CO_2e) emissions resulting in a measure of total emissions.

PacifiCorp's emissions have been declining and continue to decline related to several factors including PacifiCorp's participation in the EIM and commitment to CAISO's Extended Day-Ahead Market (EDAM), which reduces customer costs and maximizes use of non-emitting renewable resources that have no fuel cost and that generate tax credits.

The chart below in Figure 1.15 compares projected annual CO_2e emissions between the 2023 IRP Update and 2023 IRP preferred portfolios. In this graph, emissions are assigned to market purchases at a rate of 0.428 metric tons CO_2 equivalent per megawatt-hour.

In the 2023 IRP Update, emissions are higher than projected in the 2023 IRP starting in 2026. Removal of the OTR, which limited summer generation from gas and coal-fueled resources, is a significant driver. Further, over the longer-term the load forecast in the 2023 IRP Update is higher than in the 2023 IRP. Importantly, the 2023 IRP Update preferred portfolio continues to show a continued downward trajectory in emissions over time. By 2030, average annual CO_2e emissions in the 2023 IRP Update preferred portfolio are reduced by 63% against the year 2005 baseline versus a reduction of 78% against the baseline in the 2023 IRP preferred portfolio. By the end of the planning horizon, system CO_2e emissions are projected to fall from 35.1 million metric tons in 2023 to 9.3 million tons in 2042—a reduction of 73.5%.

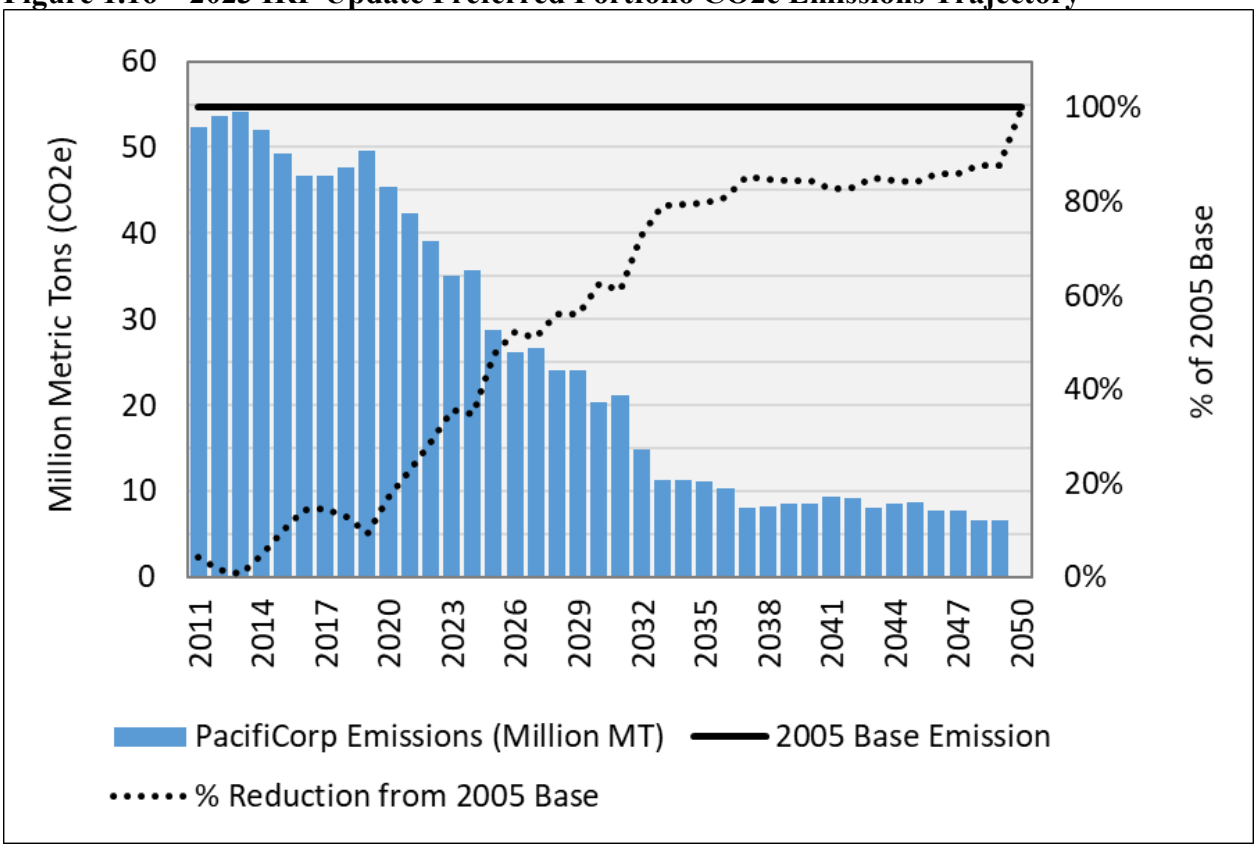
Figure 1.15 –Preferred Portfolio CO2e Emissions Comparison*



* PacifiCorp CO_2 equivalent emissions trajectory reflects actual emissions through 2022 from owned facilities, specified sources and unspecified sources. From 2023 through the end of the twenty-year planning period in 2042, emissions reflect those from the 2023 IRP Update preferred portfolio with emissions from specified sources reported in CO_2 equivalent. Market purchases are assigned a default emission factor (0.428 metric tons CO_2e/megawatt-hour). Emissions from sales are not removed. Beyond 2042, emissions reflect the rolling average emissions of each resource from the 2023 IRP update preferred portfolio through the life of the resource.

Figure 1.16 includes historical data, assigns emissions at a rate of 0.428 metric tons CO_2 equivalent per megawatt-hour to market purchases (with no credit to market sales), includes emissions associated with specified purchases, and extrapolates projections out through 2050. This graph demonstrates that relative to a 2005 baseline, of 54.6 million metric tons, system CO_2e emissions are down 47% in 2025, 63% in 2030, 80% in 2035, 84% in 2040, 84% in 2045, and 100% in 2050 (assuming that by 2050, new gas-fired resources added in the preferred portfolio are fueled with a non-emitting fuel alternative.

Figure 1.16 – 2023 IRP Update Preferred Portfolio CO2e Emissions Trajectory*



* The emissions trajectory does not incorporate clean energy targets set forth in Oregon House Bill 2021 or any other state-specific emissions trajectories.

Renewable Portfolio Standards

Figure 1.17 shows PacifiCorp's renewable portfolio standard (RPS) compliance forecast for California, Oregon, and Washington after accounting for new renewable resources in the 2023 IRP Update preferred portfolio. While these resources are included in the preferred portfolio as cost-effective system resources and are not included to specifically meet RPS targets, they nonetheless contribute to meeting RPS targets in PacifiCorp's western states.

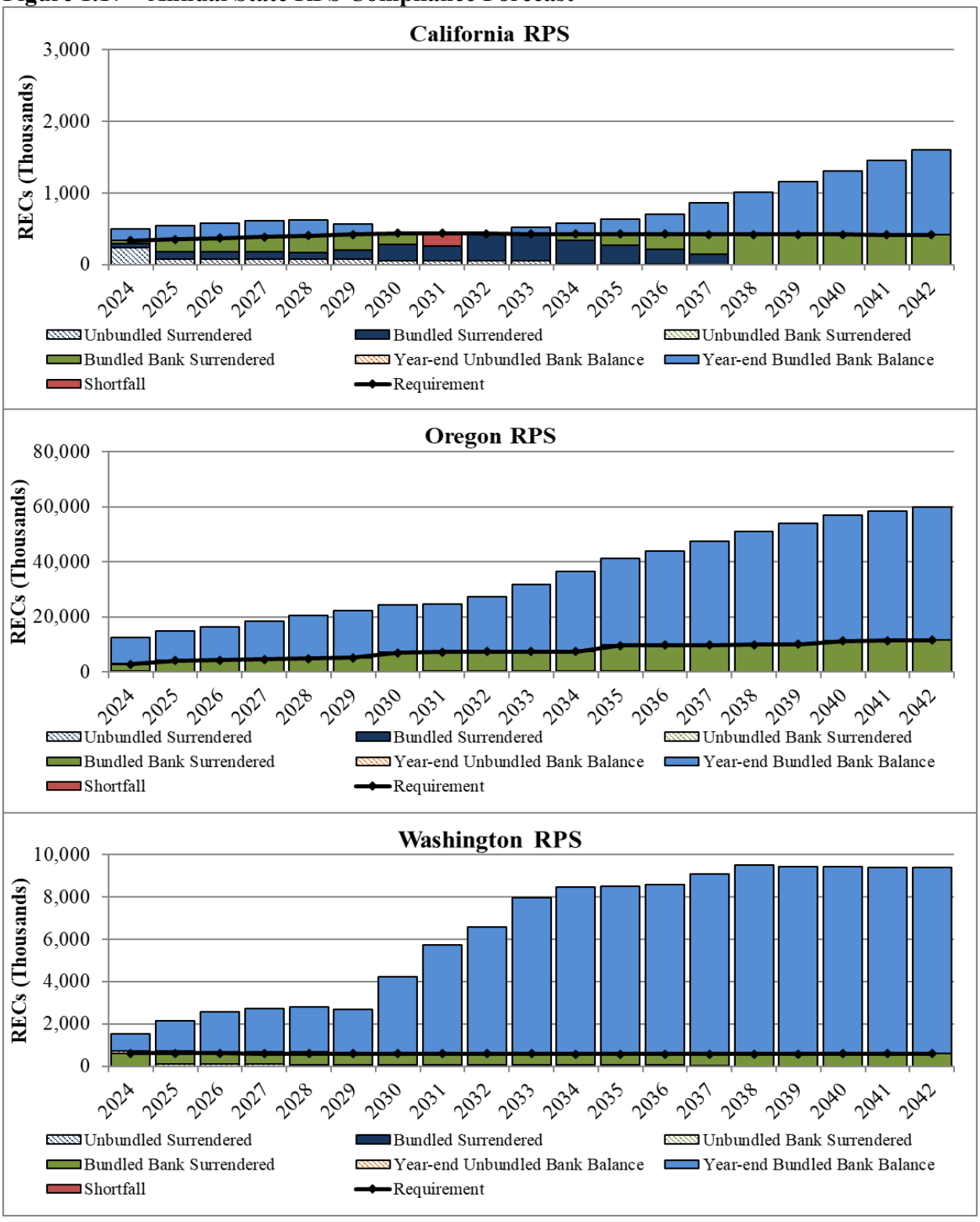
The California RPS compliance position will be met through year 2030 with owned and contracted renewable resources, as well as REC purchases. Beyond 2030, the company may need to purchase approximately ~175,000 RECs per year to meet the RPS target of 60% in years where a shortfall is projected.

Oregon RPS compliance is achieved through 2042 with the addition of new renewable resources in the 2023 IRP Update preferred portfolio.

Under PacifiCorp's 2020 Protocol and the Washington Interjurisdictional Allocation Methodology, Washington's RPS position is improved by receiving a system share of renewable resources across PacifiCorp's system, and there are no anticipated shortfalls.

While not shown, PacifiCorp meets the Utah 2025 state target to supply 20% of adjusted retail sales with eligible renewable resources with existing owned and contracted resources and new renewable resources.

Figure 1.17 – Annual State RPS Compliance Forecast



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CHAPTER 2 – INTRODUCTION

This 2023 Integrated Resource Plan (IRP) Update describes resource planning activities following the filing of the Amended Final 2023 IRP on May 31, 2023, and continues the company's commitment to develop a long-term resource plan that considers cost, risk, uncertainty, and the long-run public interest. As the owner of the IRP Update and its action plan, all policy judgments and decisions concerning the IRP Update are made by PacifiCorp considering its obligations to its customers, regulators, and shareholders.

PacifiCorp's 2023 IRP Update preferred portfolio reflects updates to load, existing resources, signed contracts, transmission options, and modeling improvements. The 2023 IRP Update also includes variant analysis for carbon capture and nuclear technologies, a range of future market and environmental policy environments, and updated analysis of state-specific planning, such as Oregon's Clean Energy Plan and Washington's Clean Energy Implementation Plan.

PacifiCorp's selection of the 2023 IRP Update preferred portfolio is supported by comprehensive data analysis described in the chapters that follow. Chapter 3 describes the current planning environment, load updates, resource updates, state and federal policy updates, and transmission upgrades. Chapter 4 provides updated load-and-resource balance information. Chapter 5 describes changes to key inputs and assumptions relative to those used for the 2023 IRP. Chapter 6 presents the updated preferred portfolio, variant study results, and additional price-policy studies. This chapter also confirms that PacifiCorp's 2023 IRP Update preferred portfolio continues to include substantial new renewables facilitated by incremental transmission investments, along with demand-side management resources, significant storage resources, the Natrium™ Demonstration Project, and peaking resources. A status update on the 2023 IRP Action Plan is provided in Chapter 7. Finally, Appendix A provides additional load forecast details.

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CHAPTER 3 – THE PLANNING ENVIRONMENT

The 2023 Integrated Resource Plan (IRP) Update reflects changes to the planning environment and assumption updates since the Amended Final 2023 IRP was filed on May 31, 2023. PacifiCorp highlights these changes relative to the 2023 IRP conditions and assumptions impacting the 2024 to 2042 planning horizon.

Material Changes to Key Planning Assumptions

Key planning assumptions that have changed from the 2023 IRP filing include:

- EPA's approval of Wyoming's OTR plan
- Stay of EPA's disapproval of Utah's OTR plan

Additional items are discussed in summary below, with details provided further within this chapter.

Federal Policy Update

Federal Climate Change Legislation

To date, no federal legislative climate change proposal has been passed by the U.S. Congress. Federal climate change legislation is not anticipated in the near term but remains possible in the mid- to long-term.

New Source Performance Standards for Carbon Emissions from New and Existing Sources – Clean Air Act § 111(b) and (d)

New Source Performance Standards are established under the Clean Air Act for certain industrial sources of emissions determined to endanger public health and welfare, including thermal electric generating units. After two previous iterations, in May 2023, the EPA proposed new rules addressing greenhouse gas emissions from new and reconstructed natural gas-fueled combustion turbines (Clean Air Act Section 111(b) rule) and existing coal- and gas- or oil-fueled steam units and natural gas-fueled combustion turbines (Clean Air Act Section 111(d) rule).

Requirements for new combustion turbines are subcategorized based on capacity factor, where low-load units would be required to meet an emission limit, intermediate-load units would be required to use a blend of low-emitting hydrogen and natural gas, and base-load units would be required to use carbon capture and sequestration (CCS) technology or a high-percentage blend of low-emitting hydrogen.

The proposed requirements for existing units would take effect January 1, 2030, through state implementation plans. Requirements for existing gas and oil-fueled steam units are subcategorized based on capacity factor, where low-load units would be subject to routine maintenance to demonstrate no increase in emissions, intermediate-load units would be subject to an emission limit of 1,500 pounds of CO_2 per megawatt-hour-gross, and base-load units would be subject to an

emission limit of 1,300 pounds of CO_2 per megawatt-hour-gross. Control equipment requirements for existing combustion turbines only apply to large, high load turbines that are greater than 300 megawatts in capacity and operate at a 50% capacity factor that is greater than 50%. These units would be required to begin using CCS with a 90% capture rate by 2035 or use a blend of low-emitting hydrogen starting in 2032. Requirements for existing coal-fueled units are subcategorized based on retirement date. Units with earlier retirement dates would be subject to less stringent requirements while units that commit to later retirement dates would be subject to annual capacity factor limits or natural gas co-firing requirements. Units that will continue operating after December 31, 2039, would be required to use CCS with a 90% carbon capture rate.

Clean Air Act Section 111 establishes a cooperative approach between the EPA and the states. The EPA establishes nationwide standards based on the best system of emissions reductions it identifies for a source category. States are then expected to develop plans to implement those standards at affected units. States may adopt the EPA's standards or develop state-specific standards that achieve the same air quality results. The EPA accepted comments on the proposal through August 8, 2023. Given the extensive comments submitted, it is uncertain how the final greenhouse gas rule will change. The scope and impacts of the final rule are uncertain until EPA takes final action on the proposals, the states submit any required state implementation plans (SIP), and any related litigation is exhausted.

Clean Air Act Criteria Pollutants – National Ambient Air Quality Standards

The Clean Air Act requires EPA to set National Ambient Air Quality Standards (NAAQS) for six criteria pollutants that have the potential of harming human health or the environment. The six pollutants are carbon monoxide, lead, ground-level ozone, nitrogen dioxide (NO_X), particulate matter (PM), and sulfur dioxide (SO_2). The standards are set at a level that protects public health with an adequate margin of safety. Areas that achieve the standards, as determined by ambient air quality monitoring, are characterized as being in attainment, while those that fail to meet the standards are designated as being nonattainment areas. Generally, sources of emissions in a nonattainment area determined to contribute to the nonattainment are required to reduce emissions. If an area is determined to be out of compliance with an established NAAQS standard, the state is required to develop a state implementation plan to bring that area into compliance, and that plan must be approved by EPA. The plan is developed so that once implemented, the NAAQS for the pollutant of concern will be achieved.

Ozone NAAQS

In October 2015, EPA issued a final rule modifying the standards for ground-level ozone from 75 parts per billion (ppb) to 70 ppb. In addition to meeting the ozone NAAQS for areas within a state, states must also conduct an analysis of cross-state air pollution to determine whether emissions from the state have a significant impact on neighboring states attaining or maintaining the ozone NAAQS. On April 6, 2022, EPA proposed its "Good Neighbor Rule" for the 2015 ozone NAAQS (the "Ozone Transport Rule" or "OTR"), which contained a federal implementation plan (FIP) with proposed revisions to the existing Cross-State Air Pollution Rule (CSAPR) framework. The CSAPR FIP is intended to address cross-state ozone transport for the 2015 ozone NAAQS through uniform federal requirements and jurisdiction. EPA's proposed FIP focused on reducing NOx, which are precursors to ozone formation. The proposed rule covered 26 states, including four western states included in the cross-state program for the first time – Wyoming, Utah, Nevada and

California. Utah and Wyoming would be included in the program based on alleged significant impacts on ozone levels in Colorado.

On May 24, 2022, the EPA proposed to disapprove the cross-state ozone transport state implementation plans (CSAPR SIPs) of numerous states to mitigate interstate ozone transport, including plans by Utah and Wyoming. Disapproval of the SIPs is a necessary prerequisite before EPA can finalize the expanded CSAPR FIP to federally regulate the western states for the first time. The proposed SIP disapprovals were made as part of a settlement agreement with environmental groups. For both Utah and Wyoming, the agency determined that, among other failings, the states should have used a 1% threshold instead of the one ppb threshold previously suggested by EPA that the states used to determine downwind impacts. Final disapproval of the SIPs would subject the states to the proposed CSAPR FIP for the 2015 ozone standard.

On January 31, 2023, EPA delayed final action on Wyoming's CSAPR SIP until December of 2023 and indicated a supplemental SIP decision may be necessary. Until a final disapproval of Wyoming's SIP, Wyoming would not be subject to the CSAPR FIP. EPA finalized disapproval of Utah's CSAPR SIP along with 18 other states and issued a partial disapproval for two additional states. EPA finalized the CSAPR FIP March 15, 2023, with some updates and timeline changes from the proposed rule but included the stringent NOx emission reduction and control equipment requirements of the proposed rule.

Numerous states and industries challenged certain provisions of the CSAPR SIP disapprovals and the final CSAPR FIP, including PacifiCorp. The state of Utah and PacifiCorp filed petitions and motions for stay of EPA's denial of the Utah state plan with EPA and the U.S. Tenth Circuit Court of Appeals (Tenth Circuit), and the motion for stay was granted by the Tenth Circuit on July 27, 2023. The stay will remain in place while the case is litigated, or until further order of the court. The court held that the agency may not enforce the CSAPR FIP while the stay remains in place. The EPA also issued several interim final rules stating that the federal rule will not take effect in states in which the SIP disapprovals have been deferred or stayed.

The EPA finalized approval of Wyoming's interstate CSAPR SIP on December 19, 2023. Given the approval of the Wyoming SIP, PacifiCorp facilities in Wyoming are not subject to the CSAPR FIP. Given the court stay of the Utah SIP disapproval, PacifiCorp was not subject to the CSAPR FIP requirements during the 2023 ozone season. The Utah ozone case was transferred to the D.C. Circuit on February 16, 2024, for adjudication of the merits, leaving the stay in place. Requirements for the 2024 ozone season and beyond will depend on the outcome of litigation. In granting the stay, the court indicated that PacifiCorp and the other petitioners are likely to succeed on the merits.

In addition to litigation over SIP disapprovals, numerous appeals of the final CSAPR FIP were filed in four different circuit courts, and at least four motions to stay the final rule have been filed in those courts. On September 25, 2023, the D.C. Circuit denied the motion to stay the CSAPR FIP filed by several state and industry parties. The denial means that states that do not have stays on their SIP disapprovals are subject to the CSAPR FIP requirements. The states of Ohio, Indiana and West Virginia filed a request for an emergency stay of the CSAPR FIP Rule with the U.S. Supreme Court on October 13, 2023. Several industry groups representing utilities as well as pipeline, paper, cement and other industries affected by the rule filed supportive requests for stay

on the same day. The U.S. Supreme Court heard oral arguments on the emergency stay requests February 21, 2024.

Regional Haze

EPA's regional haze rule, finalized in 1999, requires states to develop and implement plans to improve visibility, by 2064, in certain national park and wilderness areas. Many of these areas are in the western United States where PacifiCorp owns and operates several coal-fired generating units (Utah, Wyoming, Colorado and Montana as well as Arizona, where a PacifiCorp-owned coal unit ceased operating in 2020). The states are required to update their regional haze rule plans approximately every ten years, with second planning period revisions due in August of 2022.

Utah Regional Haze

Environmental advocacy groups filed a petition for review in the Tenth Circuit on January 19, 2021, objecting to the revised Utah regional haze SIP which included EPA's withdrawal for FIP requirements at Hunter Units 1 and 2 and Huntington Units 1 and 2 to install SCR. Briefing concluded on June 16, 2022, with EPA, Utah, PacifiCorp and the Hunter co-owners supporting Utah and EPA's determinations to approve the SIP. The Tenth Circuit set the date for oral argument on March 21, 2023. The EPA defended the SIP, with PacifiCorp and the state of Utah in support. On August 14, 2023, the Tenth Circuit denied the petition to vacate Utah's first planning period regional haze plan.

Utah Regional Haze Second Planning Period – The Utah Air Quality Division proposed, and the Utah Air Quality Board approved, final adoption of a SIP for the regional haze second planning period on July 6, 2022. The SIP differs from PacifiCorp's initial submission and requires updated mass-based NOx limits as well as a SO_2 rate-based limit for the Hunter and Huntington plants. EPA notified Utah on August 22, 2022, that its SIP submittal was complete. EPA failed to make a final determination on the Utah SIP within 12 months as required under the Clean Air Act. Utah and PacifiCorp filed a deadline suit in the Utah Federal District Court in the fall of 2023, requesting the court to order EPA to make a final determination. Environmental advocacy groups also filed several deadline suits in the D.C. Federal District Court requesting EPA to make final determinations for numerous states, including Utah. PacifiCorp intervened in the D.C. Federal District Court and requested the case be transferred to the Utah Court. Those suits are pending in the two different courts.

Wyoming Regional Haze

Naughton – In its 2014 rule, EPA approved Wyoming's determination that BART for Units 1 and 2 was low-nitrous oxide burners (LNB) and over-fired air (OFA). EPA also indicated support for the conversion of the Naughton Unit 3 to natural gas in lieu of retrofitting the unit with SCR and stated that it would expedite consideration of the gas conversion once the state of Wyoming submitted the requisite SIP amendment. Wyoming submitted its regional haze SIP amendment regarding Naughton Unit 3 to EPA on November 28, 2017. On March 7, 2017, Wyoming issued PacifiCorp a permit for Unit 3's conversion to natural gas, which allowed operation of Unit 3 on coal through January 30, 2019. PacifiCorp ceased coal operation on Unit 3 on January 30, 2019, as required by the permit. EPA's final rule approval of Wyoming's SIP revision for Naughton Unit 3 gas conversion was published in the Federal Register on March 21, 2019, with an effective date of April 22, 2019. Naughton Unit 3 currently operates on natural gas. Environmental groups petitioned EPA's approval of LNB/OFA as BART for Units 1 and 2 in the Tenth Circuit. On

August 15, 2023, the court determined EPA properly approved Wyoming's Naughton determination and denied environmental groups' petition.

Jim Bridger – On December 30, 2022, Wyoming submitted a state-approved revised regional haze SIP requiring natural gas conversion of Jim Bridger Units 1 and 2 to EPA for approval. The SIP conversion replaces the previous requirement for SCR at the units. Wyoming also issued an air permit for the natural gas conversion of Jim Bridger Units 1 and 2 on December 28, 2022. EPA is reviewing the Wyoming SIP submission for Jim Bridger and is expected to conduct a separate federal public comment process on the plan. On March 9, 2023, PacifiCorp submitted a notice of compliance and request for termination of the EPA order. The Wyoming consent decree remains in effect. The conversion process is underway at the units.

Wyodak – PacifiCorp and the state of Wyoming petitioned EPA's FIP requiring SCR at Wyodak in the Tenth Circuit. PacifiCorp and other parties successfully requested a stay of EPA's final rule relating to EPAs FIP pending court resolution of the petition. PacifiCorp subsequently submitted a request for reconsideration to EPA and engaged in a settlement process with EPA and Wyoming. The EPA, state of Wyoming and PacifiCorp signed a Settlement Agreement for Wyodak on December 16, 2020. EPA published the Settlement Agreement in the Federal Register requesting public comment on January 4, 2021. PacifiCorp submitted formal comments to the EPA on March 5, 2021, in support of the Wyodak Settlement Agreement. However, EPA did not proceed with final approval of the Settlement Agreement and re-engaged with Wyoming and PacifiCorp in mediation through the Tenth Circuit regarding paths for resolution. Litigation for the Wyodak case recommenced when the mediation process was not successful. PacifiCorp and Wyoming challenged EPA's denial of the Wyoming SIP and imposition of a FIP requiring Wyodak to install SCR equipment. On August 15, 2023, the Tenth Circuit found EPA's disapproval of Wyoming's SIP for Wyodak unlawful and remanded the SIP to EPA for further review in accordance with the requirements of the Clean Air Act

Wyoming Regional Haze Second Planning Period – On March 31, 2020, PacifiCorp submitted a four-factor reasonable progress analysis to Wyoming, which analyzed PacifiCorp's Naughton, Jim Bridger, Dave Johnston, and Wyodak plants. The four-factor analysis was used by the state in its development of the SIP for the regional haze second planning period. Wyoming required emission limits and recognized planned unit retirements during the second planning period but did not require new controls to make reasonable progress. Wyoming submitted the state's regional haze SIP for the second planning period to the EPA before the August 15, 2022, statutory deadline. EPA notified Wyoming that its submittal was complete in August of 2022. EPA failed to make a final determination on the Wyoming SIP within 12 months, as required under the Clean Air Act. Wyoming and PacifiCorp filed a deadline suit in the Wyoming Federal District Court in the fall of 2023, requesting the court to order EPA to make a final determination. Environmental advocacy groups also filed several deadline suits in the D.C. Federal District Court requesting EPA to make final determinations for numerous states, including Wyoming. PacifiCorp intervened in the D.C. Federal District Court and requested the case be transferred to the Wyoming Court. Those suits are pending in the two different courts.

Colorado Regional Haze

Colorado Second Planning Period – Colorado's regional haze SIP for the second planning period was adopted in phases in 2020 and 2021 by the Colorado Air Quality Control Commission. The SIP includes retirements of Craig Units 1 and 2 by 2025 and 2028, respectively, and Hayden Units

1 and 2 by 2028 and 2027, respectively. Colorado submitted its second planning period regional haze SIP to EPA. However, EPA has not yet acted on the Colorado SIP. The Colorado SIP is part of the deadline suit filed by environmental advocacy groups in the federal D.C. District Court.

Mercury and Hazardous Air Pollutants

On April 5, 2023, the EPA released a proposal to revise several aspects of the Mercury and Air Toxics Standards rule following the agency's review of the 2020 Residual Risk and Technology Review. The EPA proposes two specific standard changes - one applicable to all covered units and one specific to the existing lignite subcategory. The EPA proposes a more stringent standard for emissions of filterable particulate matter, the surrogate standard for non-mercury metals for coal-fueled electric generating units. The EPA proposes to reduce the filterable particulate matter emission standard by two-thirds based on a demonstration that 91% of coal-based capacity, which has not been identified as retiring before the proposed compliance period, has an emission rate at or below the proposed limit. The EPA also proposes to require continuous emissions monitoring for filterable particulate matter to demonstrate compliance with the revised standard. Compliance would be due no later than three years after the effective date of a final rule. the EPA accepted comments on the proposal through June 23, 2023. PacifiCorp is not included in the lignite subcategory. PacifiCorp has determined that compliance can be achieved with existing controls. Until the EPA takes final action on the proposal, the full impacts of the rule cannot be determined.

Coal Combustion Residuals

EPA finalized its Holistic Approach to Closure: Part A rule ("Part A rule") in September 2020. A provision in Part A allows demonstrations to be submitted to the EPA allowing for operation of unlined Coal Combustion Residual (CCR) ponds beyond the April 11, 2021, deadline for initiation of closure. PacifiCorp has submitted alternative closure demonstrations for the Naughton South Ash Pond and the Jim Bridger flue gas desulfurization (FGD) Pond 2. On October 12, 2023, Jim Bridger FGD Pond 2 ceased receiving waste, and the newly constructed FGD Pond 3 came into service. The EPA was notified on October 12, 2023, of PacifiCorp's withdrawal of its pending Part A alternative closure demonstration request. The Naughton South Ash Pond alternative closure demonstration remains under EPA review.

Separately, on August 10, 2017, the EPA issued proposed permitting guidance on how states' CCR permit programs should comply with the requirements of the final rule as authorized under the December 2016 Water Infrastructure Improvements for the Nation Act. To date, of the states in which PacifiCorp operates, only Wyoming has submitted an application to the EPA for approval of state permitting authority. The state of Utah adopted the federal final rule in September 2016, which required PacifiCorp to submit permit applications for two of its landfills by March 2017. It is anticipated that the state of Utah will submit an application to EPA for approval of its CCR permit program. Wyoming finalized its rule in late 2020 and received legislative approval in 2022. Wyoming submitted a primacy package to the EPA on February 6, 2023, and is awaiting primacy approval. The state of Wyoming filed a deadline suit in Wyoming federal district court on October 8, 2023, asking the court to require EPA to act on its application in accordance with the requirements of Resource Conservation and Recovery Act, which requires EPA to make a determination within 180 days of submission.

On May 18, 2023, the EPA proposed the legacy surface impoundments rule and accepted comment on the proposal through July 17, 2023. The proposal encompasses legacy surface impoundments, which are inactive surface impoundments at inactive facilities; and CCR management units, which include CCR surface impoundments and landfills that closed prior to October 19, 2015, inactive CCR landfills, and other areas where CCR has been or is managed directly on the land. CCR management units include all units meeting that definition at active CCR facilities, as well as those at inactive facilities with one or more legacy surface impoundment. EPA proposes to impose substantially the same regulatory obligations for both legacy surface impoundments and CCR management units as are applicable to currently regulated units, including groundwater monitoring and corrective action. All legacy surface impoundments and CCR management units would be required to initiate closure, including reclosure, within one year after the rule is finalized.

The EPA includes lists of potential legacy surface impoundments and CCR management units in the rulemaking docket, and those lists include several PacifiCorp facilities. The EPA also specifically identifies PacifiCorp's Huntington Power Plant as a potential CCR management unit damage cases based on the EPA's review of compliance information. PacifiCorp submitted comments on the proposed rule under Berkshire Hathaway Energy, and corrected the record, noting that: (1) historical impoundments, which were closed according to state requirements and no longer contain CCR or liquids, should be removed from the list of CCR management units; (2) the EPA erroneously identified the Old Landfill at PacifiCorp's Huntington generating facility as a potential damage case; and (3) two impoundments at PacifiCorp's former Carbon generating facility are incorrectly included on the list of legacy impoundments because PacifiCorp never managed or disposed of CCR materials in wastewater ponds at the former Carbon generating facility.

Until the proposals are finalized and fully litigated, PacifiCorp cannot determine whether additional action may be required. The EPA published a Notice of Data Availability (NODA) on November 14, 2023, seeking additional data in support of its legacy proposed rule. The NODA sought comments and information on two specific issues: (1) an updated list of legacy impoundments and CCR management units, based on information received from environmental groups during the comment period for the proposed rule; and (2) a risk assessment for legacy impoundments and CCR management units. The EPA included lists of potential legacy surface impoundments and CCR management units in the rulemaking docket, and those lists included several PacifiCorp facilities. Berkshire Hathaway Energy identified a number of obvious errors and inaccuracies in those lists and submitted its comments on December 11, 2023. The EPA has indicated it intends to finalize the legacy surface impoundment rule by May 2024.

Inflation Reduction Act

The Inflation Reduction Act of 2022 (IRA) is a comprehensive set of clean energy legislation, substantive details of which are still being fleshed out in the form or regulations and other guidance. The IRA contains newly structured technology-specific and technology-neutral tax credits for electric generating facilities and other clean energy incentives such as credits for Energy Storage Technology, Carbon Capture Use and Sequestration (CCUS), and hydrogen production. Furthermore, the IRA contains incentives that may affect demand such as tax credits for electric vehicles.

Features of the IRA include:

- In August 2022, President Biden signed the IRA into law. The bill directs $437b in spending towards climate and healthcare investments with over $300b dedicated to deficit reduction.
- The bill extends existing and creates new energy investment tax credit (ITC) and production tax credits (PTC) and institutes a new technology-neutral zero emission generation tax credit in 2025, supplanting the extended generation-specific credits. Eligibility expires upon meeting economy-wide emissions reduction targets. The bill also establishes a new 15% corporate minimum book tax and a new 1% excise tax on corporate stock buybacks.
- Key Energy Provisions:
    - Extends wind, geothermal, and solar investment and PTCs at full value through December 31, 2024. Solar projects are newly eligible to apply the PTC to energy generated. Additional 10% bonus credits each are available for both locating projects in communities with retired coal operations and meeting certain domestic content requirements; achieving full credit value is also conditioned on meeting wage and apprenticeship requirements.
    - Establishes new tax credits for clean hydrogen, microgrids, electric vehicle purchases, existing nuclear generation, and the domestic manufacture of solar, wind, and battery components. Value and eligibility for existing carbon capture and sequestration credits are also enhanced and expanded.
    - Institutes a new technology-neutral, zero emission generation tax credit in 2025, supplanting the extended technology-specific credits. The technology-neutral credits phase down upon meeting economy-wide emissions reduction targets.

In the 2023 IRP, resources in Utah South and all of Wyoming are assumed to receive the 10% Energy Community bonus, resulting in a 110% PTC (wind, solar, other energy resources) or 40% ITC (energy storage and peaking resources).

Clean Energy Financing Program – Inflation Reduction Act

Under the *Title 17 Clean Energy Financing Program*, the Loan Program Office (LPO) can finance projects in the United States that support clean energy deployment and energy infrastructure reinvestment to reduce greenhouse gas emissions and air pollution. *Title 17* was created by the Energy Policy Act of 2005 and has since been amended, most recently by the Infrastructure Investment and Jobs Act in 2021 and the Inflation Reduction Act in 2022. The legislation expanded the scope of *Title 17* to include certain state-supported projects and projects that reinvest in legacy energy infrastructure, and it leverages additional loan authority and funding available for projects involving innovative energy technologies.

New Credits and Considerations for Customer Resources – Inflation Reduction Act

Beginning January 1, 2023, the Clean Vehicle Credit (CVC) provisions remove manufacturer sales caps, expand the scope of eligible vehicles to include both electric vehicles and fuel cell electric vehicles, and require a traction battery that has at least seven kilowatt-hours. An available tax credit under the CVC may be limited by the vehicle's manufacturer suggested retail price and the buyer's modified adjusted gross income. Once the Treasury Department issues the critical mineral and battery component guidance, vehicles that meet the critical mineral requirements are eligible for $3,750 tax credit, and vehicles that meet the battery component requirements are eligible for a

$3,750 tax credit. Vehicles meeting both the critical mineral and the battery component requirements are eligible for a total tax credit of $7,500.

The IRA also extends federal ITC for small scale solar systems through 2034 and expands credit to include standalone energy storage systems as well. Since the passing of the IRA, the ITC has been extended past its original expiration date for ten years. For facilities beginning construction before January 1, 2025, the bill will extend the ITC for up to 30% of the cost of installed equipment for ten years and will then step down to 26% in 2033 and 22% in 2034. For projects beginning construction after 2019 that are placed in service before January 1, 2022, the ITC would be set at 26%. In addition to the new federal ITC schedule for generating facilities, the updated ITC includes credits for standalone energy storage with a capacity of at least 3 kilowatt-hours for residential customers and 5 kilowatt-hours for non-residential customers.

The IRA funds multiple programs and tax incentives to improve the energy efficiency for residential and non-residential buildings and equipment. For non-residential buildings, the IRA provides tax deductions of $0.50–5.00 per square foot (/sf) of floor area to owners of new and improved energy-saving commercial buildings depending on the percentage of energy savings and whether the contractor pays prevailing wages. Even larger broad greenhouse gas emission reduction programs under the IRA could be used to reduce emissions from commercial buildings. The IRA also provides more than $25 billion for programs and tax incentives to improve the energy efficiency of existing and new homes. In addition to program funding, the IRA enhances the 25C Energy Efficient Home Improvement Credit. This long-standing federal tax credit applies to home energy improvements such as insulation, windows, heat pumps, and furnaces. Starting in 2023, the IRA increases the credit to 30% of cost, with an annual cap of $1,200 along with smaller limits for most items, but it also allows up to $2,000 for a heat pump (in 2022 the credit is under the old rules, with lower amounts and a lifetime cap of $500).

State Policy Update

California

Under the authority of the Global Warming Solutions Act, the California Air Resources Board (CARB) adopted a greenhouse gas cap-and-trade program in October 2011, with an effective date of January 1, 2012; compliance obligations were imposed on regulated entities beginning in 2013. The first auction of greenhouse gas allowances was held in California in November 2012, and the second auction in February 2013. PacifiCorp is required to sell, through the auction process, its directly allocated allowances and purchase the required amount of allowances necessary to meet its compliance obligations.

In May 2014, CARB approved the first update to the Assembly Bill (AB) 32 Climate Change scoping plan, which defined California's climate change priorities for the next five years and set the groundwork for post-2020 climate goals. In April 2015, Governor Brown issued an executive order to establish a mid-term reduction target for California of 40% below 1990 levels by 2030. CARB was subsequently directed to update the AB 32 scoping plan to reflect the new interim 2030 target and previously established 2050 target. In July 2017, California Governor Jerry Brown signed AB 398, extending the state's California Cap and Trade program from January 1, 2021, through December 31, 2030. In 2022, CARB issued a revised scoping plan establishing emissions

reduction targets post-2030. In 2023, CARB held two workshops discussing cap and trade program changes the agency could consider. The agency is expected to open a formal rulemaking process in 2024.

In 2002, California established a renewable portfolio standard (RPS) requiring investor-owned utilities to increase procurement from eligible renewable energy resources. California's RPS requirements have been accelerated and expanded a number of times since its inception. Most recently, in September 2018, Governor Jerry Brown signed into law the 100% Clean Energy Act of 2018, Senate Bill (SB) 100, which requires utilities to procure 60% of their electricity from renewables by 2030 and enabled all the state's agencies to work toward a longer-term planning target for 100% of California's electricity to come from renewable and zero-carbon resources by December 31, 2045.

Oregon

In 2007, Oregon enacted SB 838 establishing an RPS requirement in Oregon. Under SB 838, utilities are required to deliver 25% of their electricity from renewable resources by 2025. On March 8, 2016, Governor Kate Brown signed SB 1547-B, the Clean Electricity and Coal Transition Plan, into law. SB 1547-B extends and expands the Oregon RPS requirement to 50% of electricity from renewable resources by 2040 and requires that coal-fueled resources are eliminated from Oregon's allocation of electricity by January 1, 2030. The increase in the RPS requirements under SB 1547-B is staged—27% by 2025, 35% by 2030, 45% by 2035, and 50% by 2040. The bill changes the renewable energy certificate (REC) life to five years, while allowing RECs generated from the effective date of the bill passage until the end of 2022 from new long-term renewable projects to have unlimited life. The bill also includes provisions to create a community-solar program in Oregon and encourage greater reliance on electricity for transportation.

On March 10, 2020, Oregon Governor Kate Brown issued Executive Order 20-04 (EO 20-04), which directs state agencies to take actions to reduce and regulate greenhouse gas emissions.

EO 20-04 establishes emissions reduction goals for Oregon and directs certain state agencies to take specific actions to reduce emissions and mitigate the impacts of climate change. EO 20-04 also provides overarching direction to state agencies to exercise their statutory authority to help achieve Oregon's climate goals.

In 2021, Oregon passed House Bill (HB) 2021, which directs utilities to reduce emissions levels below 2010-2012 baseline levels by 80% by 2030, 90% by 2035, and 100% by 2040. Utilities will also convene a Community Benefits and Impacts Advisory Group. PacifiCorp's 2023 IRP and 2023 IRP Update include modeling as appropriate to support HB 2021. HB 2021 also increases state requirements for small-scale renewable energy projects, to 10% of aggregate electrical capacity by 2030 and provides policy support for community-based renewable energy projects, though without specific requirements. HB 2021 is complementary to – but does not modify – Oregon's longstanding RPS requirements.

Washington

In November 2006, Washington voters approved Initiative 937 (I-937), the Washington Energy Independence Act, which imposes targets for energy conservation and the use of eligible

renewable resources on electric utilities. Under I-937, utilities must supply 15% of their energy from renewable resources by 2020. Utilities must also set and meet energy conservation targets starting in 2010.

In 2008, the Washington Legislature approved the Climate Change Framework Engrossed Second Substitute House Bill (E2SHB) 2815, which establishes the following state greenhouse gas emissions reduction limits: (1) reduce emissions to 1990 levels by 2020; (2) reduce emissions to 25% below 1990 levels by 2035; and (3) by 2050, reduce emissions to 50% below 1990 levels or 70% below Washington's forecasted emissions in 2050.

In July 2015, Governor Inslee released an executive order that directed the Washington Department of Ecology to develop new rules to reduce carbon emissions in the state. In December 2017, Washington's Superior Court concluded that the Department of Ecology did not have the authority to impose the Clean Air Rule without legislative approval. As a result, the Department of Ecology has suspended the rule's compliance requirements.

In 2019, the Washington Legislature approved the Clean Energy Transformation Act (CETA) which requires utilities to eliminate coal-fired resources from Washington rates by December 31, 2025, be carbon neutral by January 1, 2030, and establishes a target of 100% of its electricity from renewable and non-emitting resources by 2045.

Finally, in 2021, Washington passed the Climate Commitment Act, which establishes a cap-and-trade program to be implemented by no later than January 1, 2023, through the regulatory rulemaking process. The Climate Commitment Act does not modify any of PacifiCorp's obligations under CETA, and utility allowances within the cap-and-trade program are aligned with the CETA renewable energy requirements. The legislation allows – but does not require – linkage with cap-and-trade programs in jurisdictions outside of Washington state. Utilities are provided allowances at no cost to "mitigate the cost burden" of the program on customers,

Utah

In March 2008, Utah enacted the Energy Resource and Carbon Emission Reduction Initiative, which includes provisions to require utilities to pursue renewable energy to the extent that it is cost effective. It sets out a goal for utilities to use eligible renewable resources to account for 20% of their 2025 adjusted retail electric sales. PacifiCorp filed its most recent progress report with the Public Service Commission of Utah on December 29, 2023.

On March 11, 2020, the Utah Legislature passed HB 396, Electric Vehicle Charging Infrastructure Amendments, that enables PacifiCorp to create an Electrical Vehicle Infrastructure Program, with a maximum funding from customers of $50 million for all costs and expenses. The legislation allows PacifiCorp to own and operate electric vehicle charging stations and to provide investments in make-ready infrastructure to interested customers. The Public Service Commission of Utah approved a program on December 20, 2021.

In March 2024, Utah passed S.B. 224, Energy Independence Amendments. Utah's S.B. 224 does not become effective until May 1, 2024, and as such was not included in the planning environment for the 2023 Update. Portfolio modeling was well advanced by the 2024 legislative sessions and proceeded independently of those actions.

Wyoming

In March 2019, Wyoming Senate File 0159 (SF 159) was passed into law. SF 159 limits the recovery costs for the retirement of coal fired electric generation facilities, provides a process for the sale of an otherwise retiring coal fired electric generation facility, exempts a person purchasing an otherwise retiring coal fired electric generation facility from regulation as a public utility; requires purchase of electricity generated from purchased retiring coal fired electric generation facility (as specified in final bill); and provides an effective date.

Cost recovery associated with electric generation built to replace a retiring coal fired generation facility shall not be allowed by the Wyoming Public Service Commission unless the Commission has determined that the public utility made a good faith effort to sell the facility to another person prior to its retirement and that the public utility did not refuse a reasonable offer to purchase the facility or the Commission determines that, if a reasonable offer was received, the sale was not completed for a reason beyond the reasonable control of the public utility.

Under SF 159 electric public utilities, other than cooperative electric utilities, shall be obligated to purchase electricity generated from a coal fired electric generation facility purchased under agreement approved by the Commission, provided the otherwise retiring coal fired electric generation facility offers to sell some or all of the electricity from the facility to an electric public utility, the electricity is sold at a price that is no greater than the purchasing electric utility's avoided cost, the electricity is sold under a power purchase agreement, and the Commission approves a 100% cost recovery in rates for the cost of the power purchase agreement and the agreement is 100% allocated to the public utility's Wyoming customers unless otherwise agreed to by the public utility.

In March 2020, the Wyoming legislature passed House Bill 200 (HB 200), Reliable and Dispatchable Low-Carbon Energy Standards. HB 200 requires the Wyoming Public Service Commission to put in place a standard for each public utility specifying a percentage of electricity to be generated from coal-fired generation utilizing carbon capture technology by 2030. The requirement would only apply to generation allocated to Wyoming customers. HB 200 will require each public utility to demonstrate in its IRP the steps taken to achieve the electricity generation standard established by the Commission and will allow rate recovery of costs incurred by a public utility that utilizes coal-fired generation with carbon capture technology installed. The Commission finalized administrative rules to implement HB 200, which became effective in January 2022. The administrative rules require public utilities to file an initial application to establish intermediate standards for compliance by March 31, 2022, and an application to establish the final plan for compliance by March 31, 2024. PacifiCorp filed the initial application with the Commission on March 31, 2022, its first update to the initial application on March 31, 2023, and PacifiCorp's final plan on March 29, 2024 as required. During the 2024 legislative session, the Wyoming Legislature passed SF 42, low-carbon reliable energy standards amendments that has been signed into law. PacifiCorp is currently analyzing the amendments to determine how it will affect the company's plan to implement low-carbon energy portfolio standards utilizing carbon capture technology.

During the 2022 legislative session, the Wyoming Legislature passed HB 131, nuclear power plant and storage amendments, that will help facilitate development of the Natrium nuclear demonstration project. The bill modifies existing laws to clarify the authority of the United States Nuclear Regulatory Commission. The bill also requires the operator of the facility, at least 30 days prior to construction, to submit a report identifying the number of jobs expected to be created by the project, the amount of local and state taxes estimated to be generated by the project, and the anticipated benefits and impacts that will accrue to the state and local community from the project. With respect to SF 159, the bill provides that the requirements of that law shall not apply to a public utility that replaces a coal-fired generation facility with an advanced nuclear reactor. Finally, the bill exempts tax payments, but provides that, beginning July 1, 2035, the exemption only applies if not less than 80% of the uranium is sourced in the United States.

Several bills were recently signed into law from the 2024 Wyoming legislative session that PacifiCorp is evaluating that include SF 22, public service commission electricity reliability; SF 23, public service commission energy resource procurement; and SF 24, public service commission integrated resource plans. These new statutes will go into effect in 2024 and may be considered further in the next IRP.

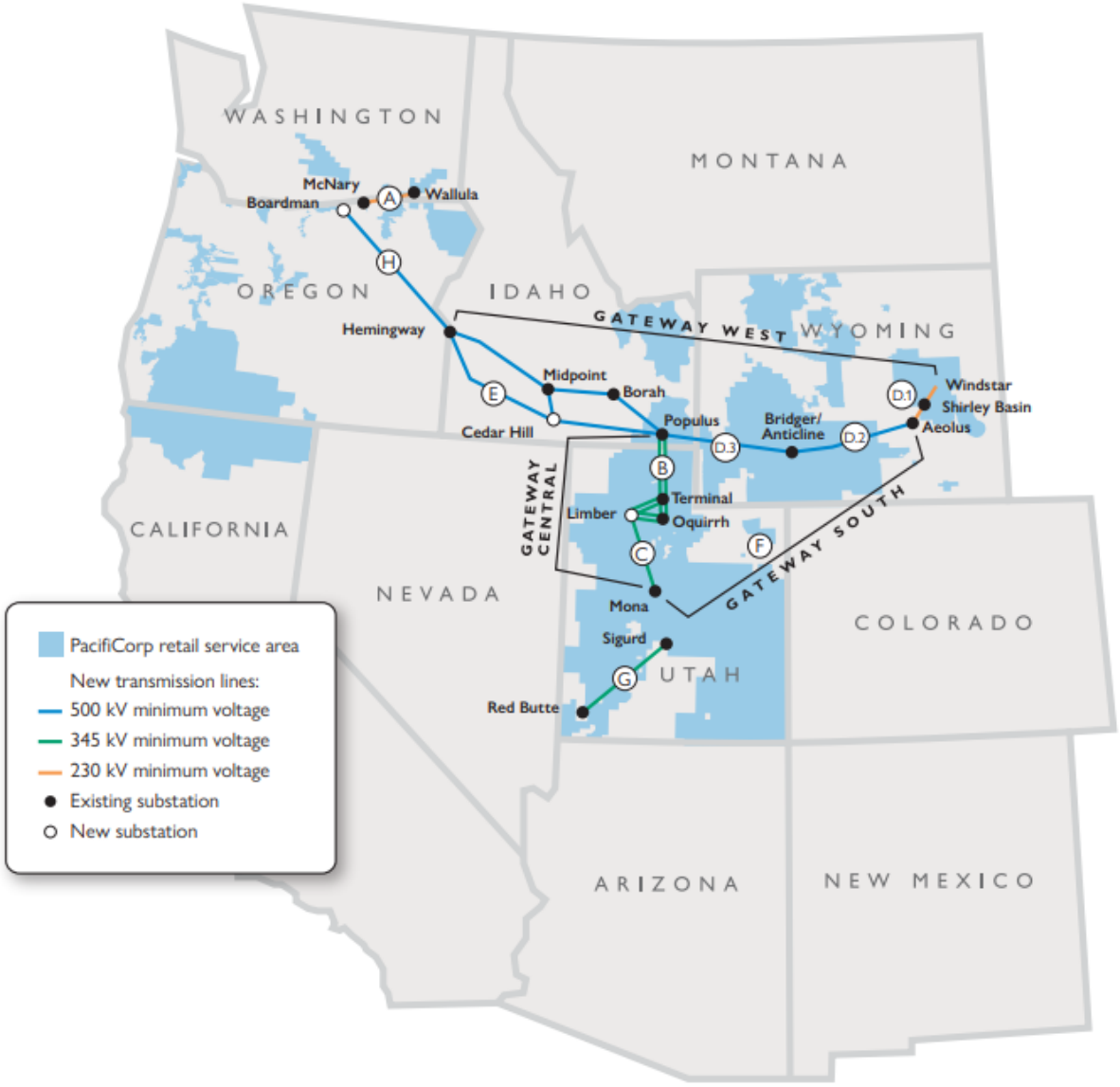
Greenhouse Gas Emission Performance Standards

California, Oregon and Washington have greenhouse gas emission performance standards applicable to all electricity generated in the state or delivered from outside the state that is no higher than the greenhouse gas emission levels of a state-of-the-art combined cycle natural gas generation facility. The standards for Oregon and California are currently set at 1,100 pounds CO_2 per megawatt-hour, which is defined as a metric measure used to compare the emissions from various greenhouse gases based on their global warming potential. In September 2018, the Washington Department of Commerce issued a new rule lowering the emissions performance standard to 925 pounds CO_2 per megawatt-hour.

Energy Gateway Transmission Program Planning

The Energy Gateway transmission project continues to play an important role in PacifiCorp's commitment to provide safe, reliable, reasonably priced electricity to meet the needs of our customers. Energy Gateway's design and extensive footprint provides needed system reliability improvements and supports the development of a diverse range of cost-effective resources required for meeting customers' energy needs. The IRP has incorporated Energy Gateway as part of a solution for delivering the least cost resource portfolio for multiple IRP planning cycles. PacifiCorp continues to develop methods, in parallel with current industry best practices and regional transmission planning requirements, to better quantify all the benefits of transmission that are essential to serve customers. For example, Energy Gateway is designed to relieve operating limitations, increase capacity, and improve operations and reliability in the existing electric transmission grid. Figure 3.1 shows a high-level geography of the Energy Gateway transmission project.

Figure 3.1 – Energy Gateway Map



This map is for general reference only and reflects current plans.
It may not reflect the final routes, construction sequence or exact line configuration.

Energy Gateway Transmission Project Updates

Wallula to McNary (Segment A)
This project was placed in service in January 2019.

Gateway West (Segments D and E)
Under the National Environmental Policy Act (NEPA), the U.S. Bureau of Land Management (BLM) has completed the environmental impact statement (EIS) for the Gateway West project. The BLM released its final EIS on April 26, 2013, followed by the record of decision (ROD) on November 14, 2013, providing a right-of-way grant for all of Segment D and for all but two segments of Segment E, followed with a record of decision on these two segments of the line on April 19, 2018:

- Gateway West (Segment D1): The project includes a new single-circuit 230 kilovolt line that will run approximately 76 miles between the existing Windstar substation in eastern Wyoming and the Aeolus substation near Medicine Bow, Wyoming, which includes a loop-in to the existing Shirley Basin 230 kilovolt substation. The Aeolus – Shirley Basin 230 kilovolt line section (16.7 miles of the 76 miles) was energized in November 2020. This project was included in the 2021 IRP for acknowledgement, and is currently under construction with an in-service date of 2024.

- Gateway West (Segment D2): This single-circuit 500 kilovolt segment was placed in service November 2020.

- Gateway West (Segment D3): A single-circuit 500 kilovolt line running approximately 200 miles between the new Anticline substation which was placed in-service in November 2020 with the energization of Gateway West Segment D.2 and the Populus substation in southeast Idaho. The line is scheduled in service 2031 at the earliest.

Gateway West (Segment E)
The Populus-to-Hemingway transmission project consists of two single-circuit 500 kilovolt lines that run approximately 500 miles between the Populus substation in eastern Idaho to the Hemingway substation in western Idaho. The estimated line in service for customers is 2036 at the earliest.

Gateway South (Segment F)
This 416-mile, high-voltage 500 kilovolt transmission line and associated infrastructure runs from the new Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah. This project was included in the 2021 IRP for acknowledgement, and is currently under construction with an in-service date of 2024.

Boardman to Hemingway (Segment H)
The Boardman to Hemingway project represents a significant improvement in the connection between PacifiCorp's east and west control areas and will help deliver more diverse resources to serve its customers in Oregon, Washington, and California. Idaho Power leads the permitting efforts on this project and PacifiCorp continues to support the permitting efforts under the conditions of the Boardman to Hemingway Transmission Project Joint Permit Funding Agreement.

The BLM's ROD was issued in November of 2017, followed by the U.S. Forest Service ROD issued on November 9, 2018. The Oregon Energy Facilities Siting Council's final order on the Site Certificate is currently under process. In January 2020, the three parties signatory to the permitting agreement entered a non-binding term sheet that addresses the terms required to move the project to the next step of construction.

In-Service Dates

Table 3.1 summarizes the in-service dates for segments of the Energy Gateway transmission project.

Table 3.1 - Energy Gateway Segment In-Service Dates

Segment & Name	Description	Approximate Mileage	Status and Scheduled In-Service
(A) Wallula-McNary	230 kV, single circuit	30 mi	• Status: completed • Placed in-service: January 2019
(B) Populus-Terminal	345 kV, double circuit	135 mi	• Status: completed • Placed in-service: November 2010
(C) Mona-Oquirrh	500 kV single circuit 345 kV double circuit	100 mi	• Status: completed • Placed in-service: May 2013
Oquirrh-Terminal	345 kV double circuit	14 mi	• Status: rights-of-way acquisition underway • Scheduled in-service: 2026
(D1) Windstar-Aeolus	New 230 kV single circuit Re-built 230 kV single circuit	118 mi	• Status: under construction • Scheduled in-service: December 2024
(D2) Aeolus-Bridger/Anticline	500 kV single circuit	140 mi	• Status: completed • Placed in-service: November 2020
(D3) Bridger/Anticline-Populus	500 kV single circuit	200 mi	• Status: permitting underway • Scheduled in-service: 2031 earliest
(E) Populus-Hemingway	500 kV single circuit	500 mi	• Status: permitting underway • Scheduled in service: 2036 earliest
(F) Aeolus-Mona/Clover	500 kV single circuit	416 mi	• Status: under construction • Scheduled in-service: December 2024
(G) Sigurd-Red Butte	345 kV single circuit	170 mi	• Status: completed • Placed in-service: May 2015
(H) Boardman-Hemingway	500 kV single circuit	290 mi	• Status: pursuing joint-development and/or firm capacity opportunities with project sponsors • Scheduled in-service: 2026-2027

Regional Markets

Increased renewable generation has contributed to the need for balancing sub-hourly demand and supply across a broader and more diverse market. For balancing purposes, PacifiCorp combined its resources with those of the CAISO through the creation of the EIM. The EIM became operational November 1, 2014, and currently has 22 utilities participating with Berkshire

Hathaway Energy Montana planning to enter in 2026.[1] The multi-service area footprint brings greater resource and geographical diversity allowing for increased reliability and cost savings in balancing generation with demand using fifteen-minute interchange scheduling and five-minute dispatch. The CAISO's role is limited to the sub-hourly scheduling and dispatching of participating EIM generators. The CAISO does not have any other grid operator responsibilities for PacifiCorp's service areas. In December 2022, PacifiCorp announced its plan to join the CAISO's Extended Day-Ahead Market which is an extension of the EIM with planning practices that are done in the day-ahead timeframe.

In December 2021, it was announced that the Western Resource Adequacy Program (WRAP), administered by the Western Power Pool (WPP), formerly known as the Northwest Power Pool, had entered the first stage of implementation. The WRAP consists of 22 participants, including PacifiCorp, who are working on the remaining program design questions and outstanding issues. The WPP has partnered with the Southwest Power Pool (SPP) to provide program operation services, including facilitating the collection of participants data to perform modeling for the upcoming seasons.[2]

This program includes two components, a forward showing (FS) planning program and an operational program to help participants that are experiencing extreme events meet customer demand. The program is intended to be a starting point and does not solve every issue facing the region but is an incremental step toward increased regional coordination. The WRAP will create a capacity resource adequacy (RA) program with a demonstration of deliverability. The region may also benefit from other forms of coordination, and while the structure and process associated with the program may serve as foundational building blocks to additional regional coordination, WPP and WRAP participants are only working to implement the capacity RA program at this time.

The WRAP does not replace or supplant the resource planning processes used by states or provinces or the regulatory requirements of the Federal Energy Regulatory Commission , North America Electric Reliability Corporation or Western Electricity Coordinating Council. The program is designed to be supplemental and complementary to those processes and requirements.

[1] https://www.westerneim.com/Pages/About/default.aspx
[2] https://www.westernpowerpool.org/news/wrap-announces-full-participation-of-phase-3a

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CHAPTER 4 – LOAD-AND-RESOURCE BALANCE

Introduction

This chapter presents an update to PacifiCorp's load-and-resource balance. Updates to PacifiCorp's long-term load forecasts (both energy and coincident peak load) for each state and the system as a whole are summarized in Appendix A. Updates to PacifiCorp's load forecast, resources, and capacity position are presented and summarized in this chapter.

System Coincident Peak Load Forecast

The 2023 Integrated Resource Plan (IRP) Update relies on PacifiCorp's May 2023 load forecast. Figure 4.1 compares PacifiCorp's most recent load forecast to the forecast used for the 2023 IRP. Figure 4.2 compares PacifiCorp's most recent coincident system peak load forecast to the forecast used for the 2023 IRP. Considering that PacifiCorp analyzes incremental energy efficiency and direct-load control programs as demand-side resource options in its IRP, both figures exclude incremental energy efficiency savings and direct-load control capacity included in the updated resource portfolio. The compounded average annual growth rate (CAGR) for system load is 2.13% over the period 2024 through 2042. The CAGR for system coincident peak is 1.80% over the period 2024 through 2042. Over the 2024 to 2027 timeframe, lower projected demand from data centers results in a lower energy and peak load forecast, while data center expectations over the long-term results in a higher forecast from 2028 and on relative to projected loads used in the 2023 IRP.

Figure 4.1 – Forecasted Annual Load (GWh)

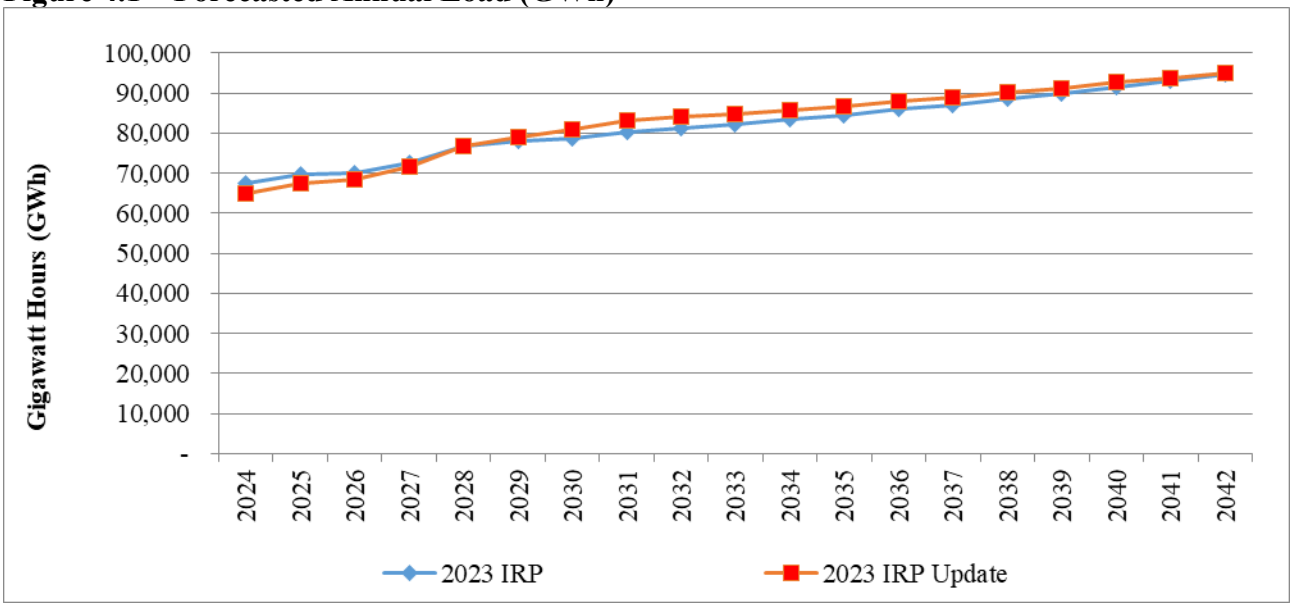
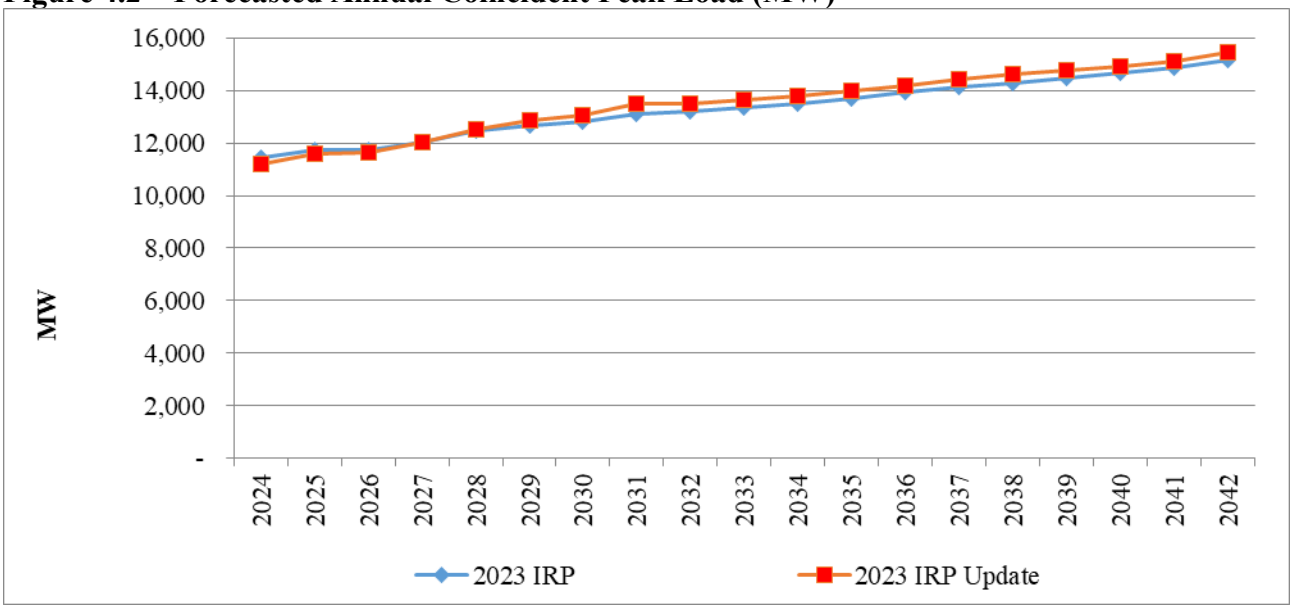


Figure 4.2 – Forecasted Annual Coincident Peak Load (MW)



Resource Updates

Table 4.1 summarizes recent long-term contracts that have been executed and modeled in PLEXOS since the 2023 IRP was prepared.

Table 4.1 – New Power Purchase Agreements

Power Purchase Agreements	Resource Type	Capacity (MW)	State	COD Year
Customer Preference / Oregon Schedule 272				
Hornshadow Solar	Solar	100	Utah	2025
Hornshadow Solar II	Solar	200	Utah	2025
	Sub-total	***300***		
Oregon Community Solar				
7 Mile Solar	Solar	1.0	Oregon	2024
Antelope Creek Solar	Solar	2.3	Oregon	2024
Orchard Knob Solar	Solar	2.3	Oregon	2024
Pine Grove Solar	Solar	1.4	Oregon	2024
Round Lake Solar	Solar	1.0	Oregon	2024
Sunset Ridge Solar	Solar	2.3	Oregon	2024
	Sub-total	***10.1***		
	Total	***310.1***		

Updated Capacity Load-and-Resource Balance

Load-and-Resource Balance Components

The capacity balance makes use of the following main component categories: resources, obligations, reserves, system position, and available front-office transactions (FOTs).

The resource categories include resources by type—thermal, peaker, hydroelectric, wind, solar, other renewable, storage, qualifying facilities, purchases, and sales. Categories in the obligation section include load, private generation, existing demand response (includes interruptible contracts), and new energy efficiency from the updated preferred portfolio.

A description of each of the resource categories is provided below.

Existing Resources

Capacity contribution is a measure of the ability for a resource to reliably meet demand. There are many possible ways to attribute capacity to specific resources and the portfolio modeling in the 2023 IRP Update does not rely on a specific capacity contribution for each resource during portfolio development, in part because the reliability benefits of the next resource of a given type may not be the same as the reliability benefits from resources of that type already included in a portfolio. Assumptions used to calculate capacity contribution in the load and resource balance presented in this chapter are described below.

Thermal and Peakers

These categories include all thermal plants. The capacity balance counts these plants at their expected availability.[1] This includes the existing fleet of coal-fueled units, coal-fueled units that have converted to natural gas-fueled, and natural gas combustion turbines and combined cycle combustion turbines. Presently, these thermal resources account for approximately three quarters of the firm capacity available in the PacifiCorp system.

Energy Storage

Energy storage resources can be called upon as needed, but only for a limited duration before they must be recharged. PacifiCorp's recent capacity contribution analysis in the 2021 IRP (Appendix K: Capacity Contribution) indicated that a four-hour duration energy storage resource would have a contribution of around 80%. For the purpose of the load and resource balance in the 2023 IRP Update, capacity contribution is based on the effective load carrying capability (ELCC) and the relationship between duration and contribution was assumed to be linear, so that energy storage with a five-hour duration would have a contribution of around 100% (less forced outages), and energy storage with a two-hour duration would have a contribution of around 40%. PacifiCorp anticipates that the capacity contribution of energy storage will fall over time as it makes up a greater portion of supply. With four gigawatts of energy storage in the 2023 IRP Update preferred portfolio, the contribution from four-hour duration energy storage may fall from 80% to 50% or lower. However, for the 2023 IRP Update load and resource balance, the current contribution level applies throughout the horizon.

[1] After derating for forced outages and maintenance during critical hours.

Variable Energy Resources: Wind and Solar

The availability of wind and solar resources is dependent on weather conditions. With access to wind and solar technologies and a broad geographic area, PacifiCorp's system is better suited to utilizing the capacity provided by wind and solar than most other utilities. However, many periods still exist in which both wind and solar output is at low levels, both in individual hours, and over an extended length of time. While short-duration energy storage can help to address a few hours of shortfalls, weather events which result in low variable energy resource output over multiple days limit the capacity contribution of these resources, as well as the contribution of short-duration energy storage. The contribution of wind and solar presented in the 2023 IRP Update load and resource balance is based on the ELCC of these resource types and is further allocated to individual resources based on their expect output during capacity critical hours, when the remaining load after netting out variable energy resources is highest. As with energy storage, PacifiCorp anticipates that the capacity contribution of wind and solar will fall over time as it makes up a greater portion of supply. With many gigawatts of wind and solar additions in the 2023 IRP Update preferred portfolio, the total contribution from these resources is likely to rise slowly from levels achieved in the next few years as the incremental benefit of each additional increment of wind and solar in critical hours will be lower than the benefits of previous additions. However, for the 2023 IRP Update load and resource balance, the current contribution level applies throughout the horizon.

Sales

Contracts for the sale of firm capacity and energy are treated the same as all other resources, except that they have a negative capacity value.

Obligation

The obligation is the total electricity demand that PacifiCorp must serve, consisting of forecasted retail load, private generation, new energy efficiency from the preferred portfolio, and existing demand response (including interruptible contracts). The following are descriptions of each of these components:

Load and Private Generation

The largest component of the obligation is retail load. In the 2023 IRP Update, the hourly retail load at a location is first reduced by hourly private generation at the same location. The system coincident peak is determined by summing the net loads for all locations (topology bubbles with loads) and then finding the highest hourly system load by year and season. Loads reported by east and west Balancing Authority Areas thus reflect loads at the time of PacifiCorp's coincident system summer and winter peaks. The energy balance counts the average load on a monthly basis. For simplicity, load net of private generation is referred to as load in the following sections.

Energy Efficiency

An adjustment is made to load to remove the projected embedded energy efficiency as a reduction to load. Due to timing issues with the vintage of the load forecast, there was a level of 2022 energy efficiency that was not incorporated in the forecast for the 2023 IRP. The 2022 energy efficiency forecast of 100 megawatts was accounted for by adding an existing energy efficiency resource in the load-and-resource balance; this adjustment was not required for the 2023 IRP Update because the 2022 projected embedded energy efficiency is included in the load forecast. The energy efficiency line includes the selected energy efficiency from the 2023 IRP Update preferred portfolio.

Demand Response

Existing demand response program capacity is categorized as a reduction to peak load. Demand response programs are those for which capacity savings occur because of active company control or advanced scheduling. Once customers agree to participate in these programs, the load reduction's timing and persistence is involuntary on their part within the agreed upon limits and parameters of the program. Program examples include residential and small commercial central air conditioner load control programs that are dispatchable, and irrigation load management and interruptible or curtailment programs (which may be dispatchable or scheduled firm, depending on the program design or event noticing requirements). Also included in the demand response category are existing interruptible contracts. PacifiCorp has had interruptible contracts for approximately 203 megawatts of peak load interruption capability for many years. These contracts are a key aspect of the retail service provided to the associated customers and absent from these contracts their demand would be different from that included in the load forecast. To maintain an alignment with the load forecast, these contracts are assumed to continue indefinitely under their current structure.

Planning Reserve Margin

Planning reserve margin (PRM) represents an incremental capacity requirement, applied as an increase to the obligation to ensure that there will be sufficient capacity available on the system to manage uncertain events (i.e., weather, outages) and known requirements (i.e., operating reserves).

System Position

The system position is the resource surplus or deficit after subtracting obligation plus required reserves from total resources. While similar, the position calculation is slightly different for the capacity and energy views of the load and resource balance. Thus, the position calculation for each of the views will be presented in their respective sections.

Capacity Balance Determination and Results

Methodology

The capacity balance is developed by first determining the system coincident peak load for each of the first ten years of the planning horizon. Then the annual firm-capacity availability of the existing resources is determined for each of these annual system summer and winter peak periods, as applicable, and summed as follows:

> **Existing Resources** = Thermal + Peaker + Hydro + Wind + Solar + Other Renewables + Storage + Purchases + Qualifying Facilities – Firm Sales

The peak load, private generation, existing demand response, and new energy efficiency from the preferred portfolio are netted together for each of the annual system summer and winter peaks, as applicable, to compute the annual peak obligation:

> **Obligation** = Load – Private Generation – Demand Response – New Energy Efficiency

The volume of reserves to be added to the obligation is then calculated. This is accomplished by the net system obligation calculated above multiplied by the 13% PRM adopted for the 2023 IRP Update. The formula for this calculation is:

Planning Reserves = Obligation x PRM

Finally, the annual system position is derived by adding the computed reserves to the obligation, and then subtracting this amount from existing resources, as shown in the following formula:

System Position = (Existing Resources) – (Obligation + Planning Reserves)

Capacity Balance Results

Table 4.2 and Table 4.3 show the annual capacity balances and component line items for the summer peak and winter peak, respectively, using a target PRM of 13% to calculate the planning reserve amount. Balances for PacifiCorp's system and the east and west control areas are shown. While east and west control area balances are broken out separately, the PacifiCorp system is planned for and dispatched on a system basis.

Table 4.2 – Summer Peak - System Capacity Load and Resource Balance without Resource Additions, 2023 IRP Update (2024-2033) (Megawatts)[2]

East	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Thermal	6,805	6,852	6,769	6,769	6,546	6,234	6,234	6,234	6,234	6,234
Peaker	352	352	352	352	352	352	352	352	352	0
Hydroelectric	60	60	60	60	60	60	60	60	60	60
Wind	504	716	701	701	701	701	681	649	649	649
Solar	279	356	600	595	591	586	582	578	574	570
Other Renewable	41	41	41	41	41	41	41	41	41	41
Storage	1	1	496	496	496	496	496	496	496	496
Purchase	120	120	120	120	120	120	120	120	120	120
Qualifying Facilities	359	358	356	354	352	350	348	346	343	334
Sale	0	0	0	0	0	0	0	0	0	0
East Existing Resources	**8,521**	**8,855**	**9,495**	**9,489**	**9,260**	**8,941**	**8,914**	**8,877**	**8,869**	**8,505**
Load	7,679	7,947	7,877	8,137	8,556	8,727	8,906	9,181	8,972	9,105
Private Generation	(102)	(143)	(111)	(141)	(174)	(213)	(256)	(304)	(151)	(175)
Existing - Demand Response	(494)	(494)	(494)	(494)	(494)	(494)	(494)	(494)	(494)	(494)
New Energy Efficiency	(132)	(217)	(269)	(343)	(450)	(534)	(614)	(743)	(814)	(932)
East Total obligation	**6,951**	**7,092**	**7,003**	**7,160**	**7,437**	**7,486**	**7,541**	**7,639**	**7,511**	**7,504**
Planning Reserve Margin (13%)	904	922	910	931	967	973	980	993	976	975
East Obligation + Reserves	7,854	8,014	7,913	8,090	8,404	8,459	8,522	8,632	8,488	8,479
East Position	666	842	1,582	1,399	855	482	393	245	381	25
Available Market Purchases	825	825	825	825	500	500	500	500	500	500
West										
Thermal	878	878	872	872	872	872	736	736	736	736
Peaker	0	0	0	0	0	0	0	0	0	0
Hydroelectric	691	695	692	700	700	699	699	699	699	699
Wind	56	56	56	56	56	56	56	56	56	56
Solar	54	54	54	53	53	53	53	52	52	52
Other Renewable	0	0	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0	0	0
Purchase	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	146	193	192	192	191	190	190	190	183	183
Sale	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)
West Existing Resources	**1,818**	**1,868**	**1,860**	**1,866**	**1,866**	**1,864**	**1,727**	**1,726**	**1,720**	**1,719**
Load	3,667	3,842	3,931	4,111	4,257	4,466	4,593	4,817	4,813	4,870
Private Generation	(45)	(69)	(68)	(89)	(111)	(137)	(166)	(201)	(111)	(130)
Existing - Demand Response	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)
New Energy Efficiency	(64)	(123)	(134)	(142)	(176)	(205)	(211)	(263)	(252)	(269)
West Total obligation	**3,538**	**3,629**	**3,708**	**3,859**	**3,949**	**4,104**	**4,195**	**4,331**	**4,429**	**4,450**
Planning Reserve Margin (13%)	460	472	482	502	513	533	545	563	576	578
West Obligation + Reserves	3,998	4,101	4,190	4,361	4,462	4,637	4,740	4,895	5,005	5,028
West Position	(2,179)	(2,232)	(2,331)	(2,495)	(2,596)	(2,773)	(3,013)	(3,169)	(3,285)	(3,309)
Available Market Purchases	3,000	3,000	3,000	3,000	500	500	500	500	500	500
System										
Total Resources	10,339	10,724	11,355	11,355	11,125	10,804	10,642	10,603	10,589	10,224
Obligation	10,489	10,721	10,711	11,019	11,386	11,589	11,736	11,970	11,940	11,954
Planning Reserves (13%)	1,364	1,394	1,392	1,432	1,480	1,507	1,526	1,556	1,552	1,554
Obligation + Reserves	11,852	12,114	12,103	12,451	12,867	13,096	13,262	13,527	13,492	13,508
System Position	(1,513)	(1,391)	(748)	(1,096)	(1,741)	(2,292)	(2,621)	(2,924)	(2,904)	(3,284)
Available Market Purchases	3,825	3,825	3,825	3,825	1,000	1,000	1,000	1,000	1,000	1,000
Uncommitted FOTs to meet remaining Need	1,513	1,391	748	1,096	1,000	1,000	1,000	1,000	1,000	1,000
Net Surplus/(Deficit)	0	0	0	0	(741)	(1,292)	(1,621)	(1,924)	(1,904)	(2,284)

[2] The DSM line includes selected Class 2 DSM from the 2023 IRP Update resource portfolio.

Table 4.2 (cont.) – Summer Peak - System Capacity Load and Resource Balance without Resource Additions, 2023 IRP Update (2034-2042) (Megawatts)[3]

East	2034	2035	2036	2037	2038	2039	2040	2041	2042
Thermal	6,234	6,234	6,234	4,802	4,104	4,104	2,890	2,890	2,890
Peaker	0	0	0	0	0	0	0	0	0
Hydroelectric	60	60	60	60	60	59	60	60	60
Wind	649	649	649	649	649	649	649	547	547
Solar	567	563	559	525	521	518	515	511	508
Other Renewable	41	41	41	41	13	13	13	13	13
Storage	495	495	495	495	495	495	495	495	495
Purchase	120	120	120	120	120	120	120	120	120
Qualifying Facilities	330	328	323	272	270	263	262	261	259
Sale	0	0	0	0	0	0	0	0	0
East Existing Resources	**8,496**	**8,490**	**8,481**	**6,965**	**6,233**	**6,221**	**5,003**	**4,897**	**4,892**
Load	9,223	9,361	9,564	9,726	9,867	9,980	10,112	10,248	10,428
Private Generation	(197)	(220)	(242)	(265)	(287)	(309)	(330)	(352)	(374)
Existing - Demand Response	(494)	(494)	(494)	(494)	(494)	(494)	(494)	(494)	(494)
New Energy Efficiency	(1,037)	(1,124)	(1,209)	(1,317)	(1,400)	(1,498)	(1,589)	(1,653)	(1,752)
East Total obligation	**7,494**	**7,523**	**7,618**	**7,649**	**7,686**	**7,679**	**7,699**	**7,749**	**7,808**
Planning Reserve Margin (13%)	974	978	990	994	999	998	1,001	1,007	1,015
East Obligation + Reserves	8,468	8,501	8,608	8,644	8,685	8,677	8,699	8,756	8,823
East Position	27	(11)	(127)	(1,679)	(2,452)	(2,456)	(3,696)	(3,860)	(3,931)
Available Market Purchases	500	500	500	500	500	500	500	500	500
West									
Thermal	736	736	736	500	500	500	500	500	500
Peaker	0	0	0	0	0	0	0	0	0
Hydroelectric	699	699	699	699	699	699	699	699	707
Wind	56	56	56	56	56	56	56	56	56
Solar	52	51	51	51	51	50	50	50	48
Other Renewable	0	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0	0
Purchase	0	0	0	0	0	0	0	0	0
Qualifying Facilities	182	182	181	162	160	159	159	158	159
Sale	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)
West Existing Resources	**1,718**	**1,718**	**1,717**	**1,461**	**1,459**	**1,457**	**1,457**	**1,456**	**1,464**
Load	4,929	4,995	5,068	5,176	5,246	5,318	5,384	5,461	5,647
Private Generation	(148)	(163)	(178)	(193)	(208)	(222)	(236)	(250)	(264)
Existing - Demand Response	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)
New Energy Efficiency	(299)	(322)	(314)	(357)	(355)	(366)	(396)	(391)	(429)
West Total obligation	**4,461**	**4,489**	**4,555**	**4,605**	**4,662**	**4,709**	**4,731**	**4,799**	**4,933**
Planning Reserve Margin (13%)	580	584	592	599	606	612	615	624	641
West Obligation + Reserves	281	262	278	242	251	247	219	233	213
West Position	1,438	1,456	1,439	1,219	1,208	1,211	1,238	1,223	1,251
Available Market Purchases	500	500	500	500	500	500	500	500	500
System									
Total Resources	10,214	10,208	10,198	8,426	7,691	7,679	6,460	6,353	6,355
Obligation	11,956	12,012	12,173	12,254	12,347	12,389	12,430	12,547	12,741
Planning Reserves (13%)	1,554	1,562	1,583	1,593	1,605	1,611	1,616	1,631	1,656
Obligation + Reserves	13,510	13,574	13,756	13,848	13,952	13,999	14,045	14,179	14,398
System Position	(3,296)	(3,366)	(3,558)	(5,422)	(6,261)	(6,320)	(7,586)	(7,826)	(8,042)
Available Market Purchases	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Uncommitted FOTs to meet remaining Need	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Net Surplus/(Deficit)	(2,296)	(2,366)	(2,558)	(4,422)	(5,261)	(5,320)	(6,586)	(6,826)	(7,042)

[3] The DSM line includes selected Class 2 DSM from the 2023 IRP Update resource portfolio.

Table 4.3 – Winter Peak – System Capacity Load and Resource Balance without Resource Additions, 2023 IRP Update (2024-2033) (Megawatts) [4]

East	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Thermal	6,828	6,875	6,795	6,795	6,578	6,264	6,264	6,264	6,264	6,264
Peaker	323	323	323	323	323	323	323	323	323	0
Hydroelectric	36	36	36	36	36	36	36	36	36	36
Wind	442	602	594	594	594	594	579	552	552	552
Solar	197	288	408	405	402	399	396	393	391	388
Other Renewable	34	34	34	34	34	34	34	34	34	34
Storage	1	1	468	468	468	468	468	468	468	468
Purchase	172	172	172	172	172	172	172	172	172	172
Qualifying Facilities	284	283	281	279	278	276	275	273	271	263
Sale	0	0	0	0	0	0	0	0	0	0
East Existing Resources	**8,317**	**8,613**	**9,111**	**9,107**	**8,884**	**8,566**	**8,547**	**8,515**	**8,510**	**8,177**
Load	5,724	6,097	6,171	6,444	6,754	6,700	6,872	7,145	7,214	7,387
Private Generation	(2)	0	0	0	0	(8)	(10)	0	0	0
Existing - Demand Response	(463)	(463)	(463)	(463)	(463)	(463)	(463)	(463)	(463)	(463)
New Energy Efficiency	(102)	(111)	(172)	(232)	(299)	(470)	(569)	(529)	(615)	(693)
East Total obligation	**5,158**	**5,523**	**5,536**	**5,749**	**5,993**	**5,760**	**5,830**	**6,153**	**6,137**	**6,232**
Planning Reserve Margin (13%)	671	718	720	747	779	749	758	800	798	810
East Obligation + Reserves	5,829	6,241	6,256	6,496	6,772	6,508	6,588	6,953	6,934	7,042
East Position	2,488	2,372	2,855	2,610	2,112	2,058	1,958	1,563	1,575	1,135
Available Market Purchases	825	825	825	825	800	800	800	800	800	800
West										
Thermal	878	878	874	874	874	874	736	736	736	736
Peaker	0	0	0	0	0	0	0	0	0	0
Hydroelectric	538	544	542	555	556	555	555	553	554	554
Wind	74	74	74	74	74	74	74	74	74	74
Solar	44	43	43	43	42	42	42	41	40	40
Other Renewable	0	0	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0	0	0
Purchase	1	1	1	1	1	1	1	1	1	1
Qualifying Facilities	116	127	127	127	127	126	126	126	120	120
Sale	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)
West Existing Resources	**1,639**	**1,657**	**1,650**	**1,662**	**1,662**	**1,660**	**1,522**	**1,520**	**1,514**	**1,513**
Load	3,711	3,577	3,676	3,858	4,024	4,476	4,539	4,419	4,475	4,524
Private Generation	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Existing - Demand Response	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
New Energy Efficiency	(89)	(96)	(126)	(167)	(221)	(324)	(378)	(341)	(368)	(415)
West Total obligation	**3,611**	**3,470**	**3,539**	**3,681**	**3,792**	**4,142**	**4,151**	**4,068**	**4,095**	**4,098**
Planning Reserve Margin (13%)	469	451	460	479	493	538	540	529	532	533
West Obligation + Reserves	4,081	3,921	3,999	4,160	4,285	4,680	4,691	4,596	4,628	4,630
West Position	(2,441)	(2,265)	(2,350)	(2,497)	(2,623)	(3,020)	(3,169)	(3,076)	(3,114)	(3,117)
Available Market Purchases	3,000	3,000	3,000	3,000	700	700	700	700	700	700
System										
Total Resources	9,956	10,270	10,761	10,769	10,547	10,226	10,069	10,035	10,024	9,690
Obligation	8,769	8,993	9,076	9,430	9,785	9,901	9,981	10,220	10,232	10,329
Planning Reserves (13%)	1,140	1,169	1,180	1,226	1,272	1,287	1,298	1,329	1,330	1,343
Obligation + Reserves	9,909	10,162	10,255	10,656	11,057	11,189	11,279	11,549	11,562	11,672
System Position	47	108	505	113	(511)	(962)	(1,210)	(1,514)	(1,538)	(1,982)

[4] The DSM line includes selected Class 2 DSM from the 2023 IRP Update resource portfolio.

Table 4.3 (cont.) – Winter Peak – System Capacity Load and Resource Balance without Resource Additions, 2023 IRP Update (2034-2042) (Megawatts)[5]

East	2034	2035	2036	2037	2038	2039	2040	2041	2042
Thermal	6,264	6,264	6,264	4,815	4,117	4,117	2,854	2,854	2,854
Peaker	0	0	0	0	0	0	0	0	0
Hydroelectric	36	36	36	36	36	36	36	36	36
Wind	552	552	552	552	552	552	552	470	470
Solar	385	383	380	357	354	352	350	347	345
Other Renewable	34	34	34	34	8	8	8	8	8
Storage	467	467	467	467	467	467	467	467	467
Purchase	172	172	172	172	172	172	172	172	172
Qualifying Facilities	259	257	254	213	212	207	206	205	204
Sale	0	0	0	0	0	0	0	0	0
East Existing Resources	**8,169**	**8,165**	**8,159**	**6,645**	**5,918**	**5,911**	**4,645**	**4,560**	**4,556**
Load	7,329	7,518	7,607	7,745	7,870	8,007	8,186	8,326	8,472
Private Generation	(19)	(21)	(23)	(25)	(28)	(30)	(32)	(0)	(36)
Existing - Demand Response	(463)	(463)	(463)	(463)	(463)	(463)	(463)	(463)	(463)
New Energy Efficiency	(1,024)	(1,147)	(1,263)	(1,464)	(1,573)	(1,658)	(1,743)	(1,868)	(2,048)
East Total obligation	**5,823**	**5,887**	**5,858**	**5,793**	**5,807**	**5,857**	**5,949**	**5,995**	**5,925**
Planning Reserve Margin (13%)	757	765	761	753	755	761	773	779	770
East Obligation + Reserves	6,580	6,652	6,619	6,546	6,562	6,618	6,722	6,774	6,695
East Position	1,590	1,513	1,540	99	(644)	(707)	(2,077)	(2,215)	(2,138)
Available Market Purchases	800	800	800	800	800	800	800	800	800
West									
Thermal	736	736	736	499	499	499	499	499	499
Peaker	0	0	0	0	0	0	0	0	0
Hydroelectric	554	554	554	554	554	554	554	554	565
Wind	74	74	74	74	74	74	74	74	74
Solar	39	39	39	39	39	38	38	38	38
Other Renewable	0	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0	0
Purchase	1	1	1	1	1	1	1	1	1
Qualifying Facilities	120	120	119	105	104	103	103	103	103
Sale	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)
West Existing Resources	**1,513**	**1,513**	**1,512**	**1,261**	**1,260**	**1,259**	**1,258**	**1,258**	**1,269**
Load	4,770	4,917	4,986	4,938	5,058	5,133	5,273	5,285	5,394
Private Generation	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Existing - Demand Response	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
New Energy Efficiency	(588)	(634)	(678)	(720)	(755)	(801)	(844)	(838)	(943)
West Total obligation	**4,171**	**4,272**	**4,297**	**4,207**	**4,293**	**4,321**	**4,418**	**4,436**	**4,440**
Planning Reserve Margin (13%)	542	555	559	547	558	562	574	577	577
West Obligation + Reserves	(46)	(79)	(120)	(173)	(196)	(239)	(269)	(261)	(365)
West Position	1,559	1,591	1,632	1,433	1,456	1,498	1,528	1,519	1,634
Available Market Purchases	700	700	700	700	700	700	700	700	700
System									
Total Resources	9,683	9,678	9,671	7,906	7,178	7,169	5,903	5,818	5,825
Obligation	9,994	10,159	10,155	10,001	10,100	10,178	10,367	10,431	10,365
Planning Reserves (13%)	1,299	1,321	1,320	1,300	1,313	1,323	1,348	1,356	1,347
Obligation + Reserves	11,293	11,480	11,475	11,301	11,413	11,501	11,715	11,787	11,712
System Position	(1,611)	(1,802)	(1,803)	(3,395)	(4,235)	(4,332)	(5,811)	(5,970)	(5,887)
Available Market Purchases	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500
Uncommitted FOTs to meet remaining Need	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500
Net Surplus/(Deficit)	(111)	(302)	(303)	(1,895)	(2,735)	(2,832)	(4,311)	(4,470)	(4,387)

[5] The DSM line includes selected Class 2 DSM from the 2023 IRP Update resource portfolio.

Figure 4.3 and Figure 4.4 are graphic representations of the above tables for the 2023 IRP Update annual capacity position for the summer system, winter system respectively. Also shown in the system capacity position graphs are the capacity contribution from uncommitted FOTs, which as discussed above, are provided for informational purposes.

Figure 4.3 – Summer System Capacity Position Trend

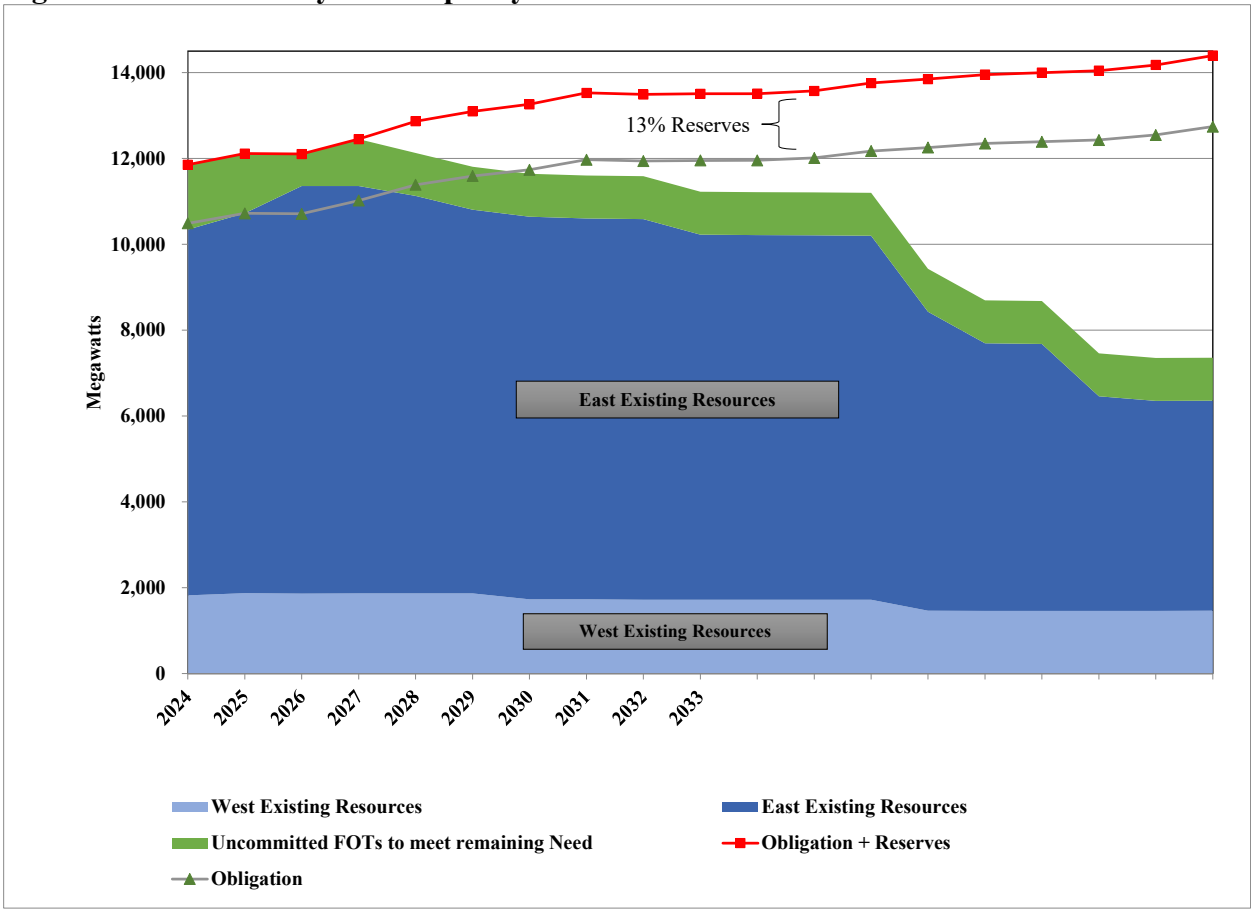
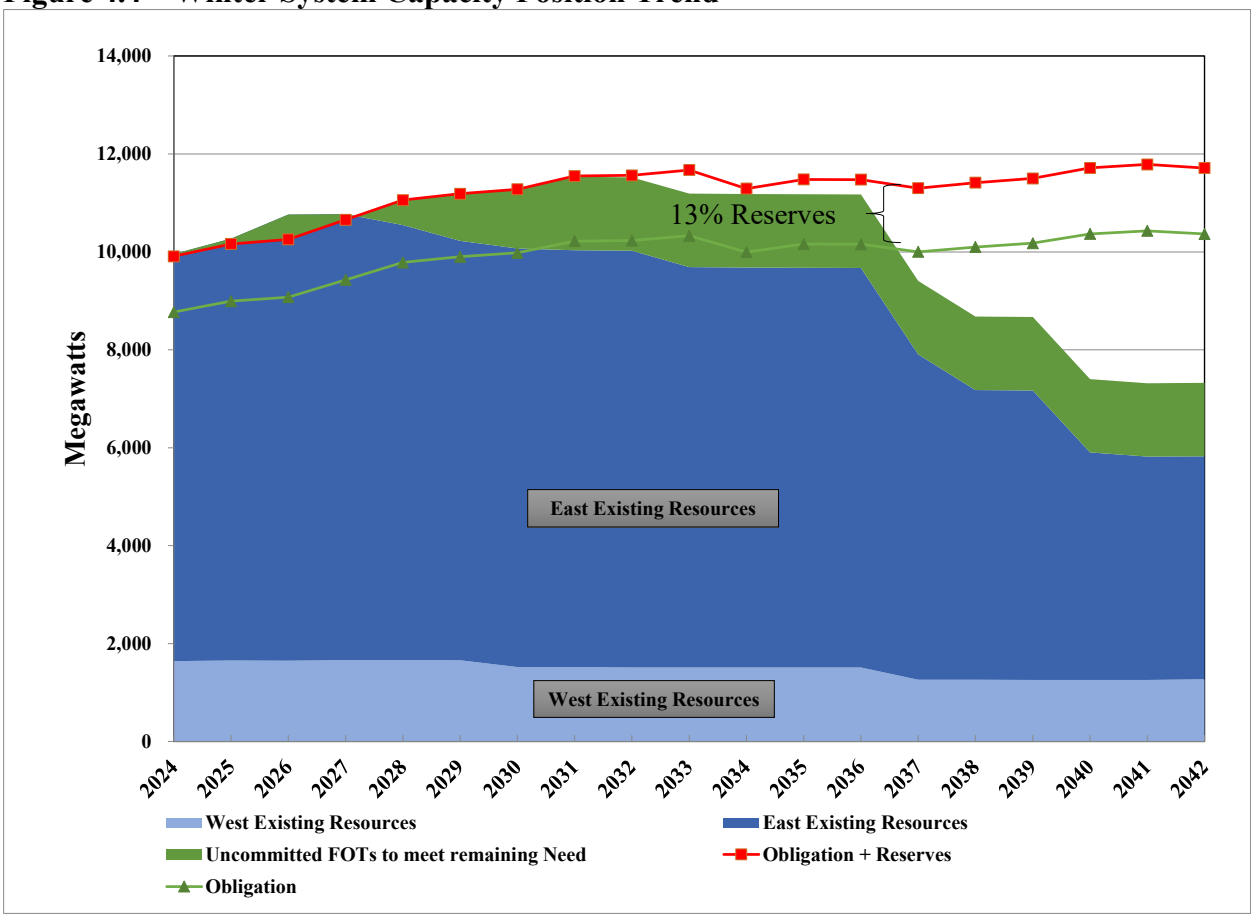


Figure 4.4 – Winter System Capacity Position Trend



CHAPTER 5 – MODELING AND ASSUMPTIONS

General Assumptions

The study period for the 2023 IRP Update is 2024-2042, with a focus on the 2024-2028 planning horizon.[1] While many assumptions are unchanged from the 2023 IRP, PacifiCorp has materially updated certain assumptions in the 2023 IRP Update as discussed below.

Inflation Rates

The 2023 IRP Update model simulations and cost data reflect PacifiCorp's corporate inflation rate schedule unless otherwise noted. A single annual escalation rate value of 2.28% is assumed, consistent with the 2023 IRP. The annual escalation rate reflects the average of annual inflation rate projections for the 20-year study period, using PacifiCorp's September 2023 inflation curve. PacifiCorp's inflation curve is a straight average of forecasts for Gross Domestic Product inflator and Consumer Price Index.

Discount Factor

The discount rate used in present-value calculations is based on PacifiCorp's after-tax weighted average cost of capital (WACC). The value used for the 2023 IRP Update is 6.69%. The use of the after-tax WACC complies with the Public Utility Commission of Oregon's IRP guideline 1a, which requires that the after-tax WACC be used to discount all future resource costs.[2] Present-value revenue requirement values reported in the 2023 IRP Update are reported in 2023 dollars.

Front Office Transactions

Although PacifiCorp's understanding of likely market purchase availability is evolving with the emergence of Western Region Adequacy Program (WRAP) relationships with other utilities, as well as the expansion of regional energy markets, no added information has emerged to justify changing assumptions from the existing markets modeled in the 2023 IRP. However, for the 2023 IRP Update, PacifiCorp is now modeling additional potential for market purchases in Wyoming to reflect its increased transmission system connectivity to other utilities. Table 5.1 reports the available FOT modeling assumptions; identifying the market hub, product type, annual capacity limit, and availability associated with the product. PacifiCorp develops its front office transaction (FOT) planning limits based upon its active participation in wholesale power markets, its view of physical delivery constraints, market liquidity and depth, and with consideration of regional resource supply.

[1] As year 2023 has passed into history, it is not generally reported in this 2023 IRP Update; however, some workpapers will still contain 2023 information as an artifact of developing data for the remainder of the 20-year modeling horizon.
[2] Public Utility Commission of Oregon, Order No. 07-002, Docket No. UM 1056, January 8, 2007.

Table 5.1 - Maximum Available Front Office Transaction Quantity by Market Hub

Market Hub	Availability Limit (MW)			Change from 2023 IRP	
	2023 IRP Update				
	Short-term (2023-2027)	Long-term (2028-2042)		Summer	Winter
		Summer	Winter		
Mid-Columbia (Mid-C)	1979	500	350	-	-
California Oregon Border (COB)	424	0	250	-	-
Nevada Oregon Border (NOB)	200	0	100	-	-
4 Corners (4C)	398	0	0	-	-
Mona	325	0	300	-	-
Wyoming	500	500	500	New	New
Total	**3826**	**1000**	**1500**		

Stochastic Parameters

Stochastic parameters assumed in the 2023 IRP Update are consistent with those applied in the 2023 IRP. PacifiCorp provided a detailed description of its stochastic parameters and their development in Volume II, Appendix H of the 2023 IRP – Amended Final, filed May 31, 2023.

Flexible Reserve Study

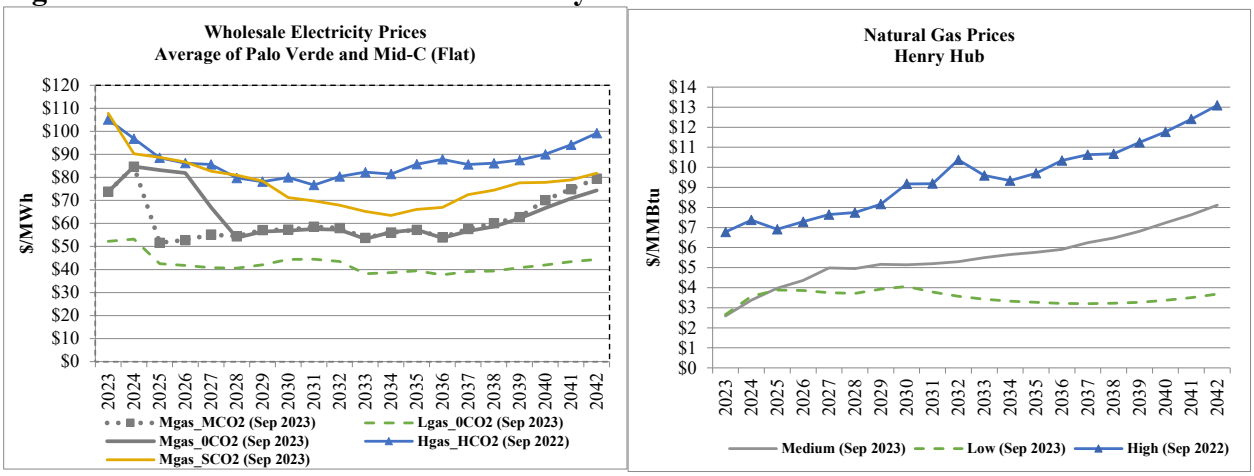
PacifiCorp applied its Flexible Reserve Study methodology from the 2023 IRP in its 2023 IRP Update. PacifiCorp provided a detailed description of its Flexible Reserve Study in Volume II, Appendix F of the 2023 IRP.

Natural Gas and Power Market Price Updates

Portfolio modeling for the 2023 IRP Update was prepared using five market price forecasts. This includes the official forward price curve (OFPC) and four scenarios.

Figure 5.1 summarizes the five wholesale electricity price forecasts and three natural gas price forecasts used in the base and variant studies for the 2023 IRP Update. Power prices are higher in the near term. All five power price scenarios trend higher beginning in different years in the forecast but escalate at different increasing rates. Natural gas prices start low then grow at different escalation rates depending on the scenario.

Figure 5.1 – Nominal Wholesale Electricity and Natural Gas Price Scenarios



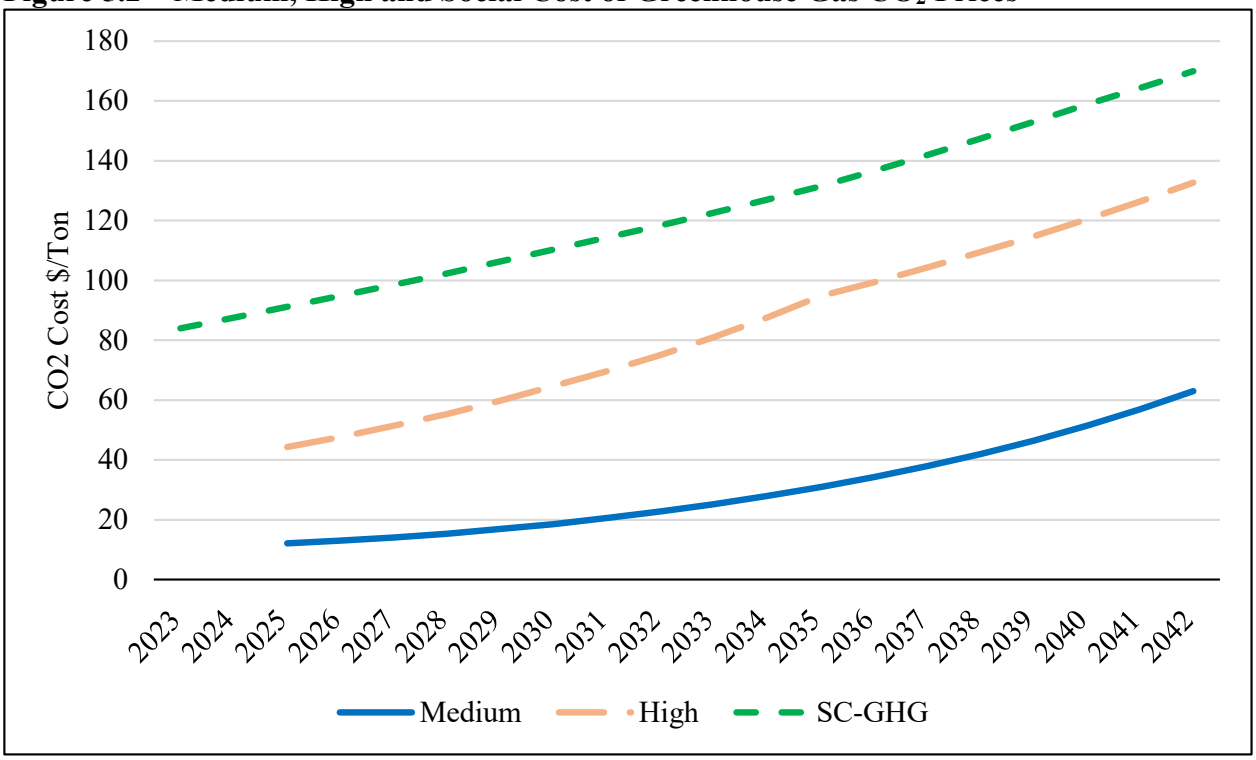
PacifiCorp's September 30, 2023, OFPC is used to represent medium natural gas price assumptions with no CO_2 prices for the "MN" price-policy scenario. OFPCs are produced for both natural gas and power prices by point of delivery. For both gas and electricity, starting with the prompt month, the front 36 months of the OFPC reflect market forwards at the close of a given trading day.[3] As such, these 36 months are market forwards as of September 2023. The blending period (months 37 through 48) is calculated by averaging the month-on-month market forward from the prior year with the month-on-month fundamentals-based price from the subsequent year. The fundamentals portion of the natural gas OFPC reflects an expert third-party multi-client "off-the-shelf" price forecast. The fundamental portion of the electricity OFPC reflects prices as forecast by AURORAxmp[4] (Aurora), a WECC-wide market model. Aurora uses the expert third-party natural gas price forecast to produce a consistent electricity price forecast for market hubs in which PacifiCorp participates. PacifiCorp updates its natural gas price forecasts in this quarter for the OFPC and, as a corollary, the electricity OFPC is also updated.

Carbon Dioxide Emission Policy

Consistent with the 2023 IRP, PacifiCorp used four different CO_2 price scenarios in the 2023 IRP Update—zero, medium, high, and a price forecast that aligns with the social cost of greenhouse gases. The modeled CO_2 price scenarios are *not* intended to explicitly account for a future monetary tax on CO_2 emissions. Instead, these costs capture the trend of federal policies that incentivize reduced emissions through benefits (i.e., production tax credits) or impose restrictions or costs or other market dynamics that drive the need for zero-emission resources and the relative ability for such resources to be developed and procured. Such scenarios reflect the reality of the current federal regulatory landscape, as illustrated in Chapter 3, and ensure that the PacifiCorp's preferred portfolio is least-cost for its customers over time. This treatment further allows the IRP analysis to examine the costs, risks and robustness of portfolios when viewed under a range of futures. Figure 5.2 illustrates the CO_2 proxy price curves used in the 2023 IRP Update.

[3] The September 2023 OFPC prompt month is November 2023; October 2023 would be traded as "balance of month" when the OFPC is released.
[4] AURORAxmp is a proprietary production cost simulation model, developed by Energy Exemplar, LLC.

Figure 5.2 – Medium, High and Social Cost of Greenhouse Gas CO_2 Prices



The medium and high scenario are derived from a variety of sources, including government and electric utility forecasts, and expert third-party multi-client "off-the-shelf" subscription services. PacifiCorp grouped these forecasts around the median low and median high forecast. The highest grouping, consisting of six different forecasts, was averaged to form the high price case. The lowest grouping, also consisting of six different forecasts, was averaged to form the medium case. These scenarios apply a CO_2 proxy price beginning 2025.

PacifiCorp also incorporated the social cost of greenhouse gas in compliance with Washington Revised Code of Washington 19.280.030. The 2023 IRP Update includes an adjusted cost of greenhouse gas emission reflecting inflation, defined by the Washington Utilities and Transportation Commission.[5]

The social cost of greenhouse gas emissions (SC-GHG) is assumed to apply in all years of the study horizon. The SC-GHG is applied such that the price for the SC-GHG is reflected in market prices and dispatch costs for the purposes of developing each portfolio (i.e., incorporated into capacity expansion optimization modeling). Aligned with Washington Staff's suggested treatment, in SC-GHG studies, system operations also include the SC-GHG once the portfolios are determined, presenting the risk that this operational assumption will not be aligned with actual market forces (i.e., market transactions at the Mid-Columbia market do not reflect the social cost of greenhouse gases and PacifiCorp does not directly incur emission costs at the price assumed for the social cost of greenhouse gases).

In all scenarios, emissions from the Chehalis natural gas plant incur the forecasted cost of allowances under the cap-and-invest program established in the Climate Commitment Act passed

[5] Washington Utilities and Transportation Commission, Order 04, Docket No. U-190730, July 27, 2023

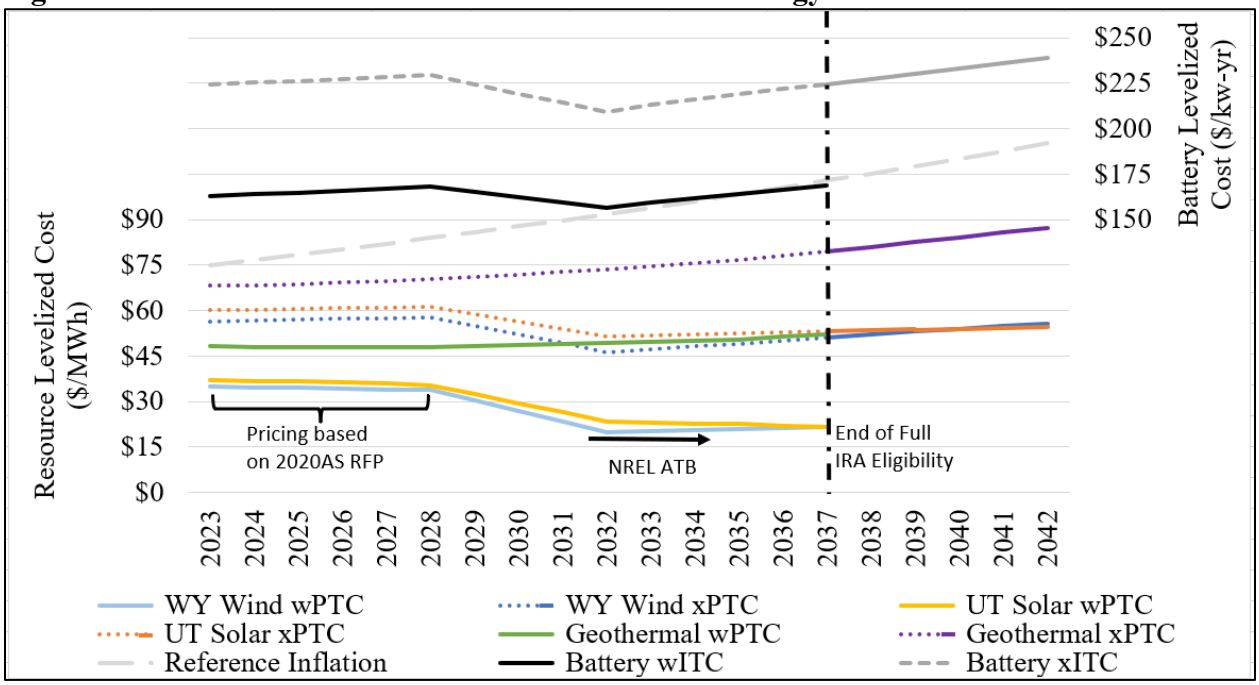
by the Washington Legislature in 2021. This is in addition to the assumed federal CO2 policy represented in the zero, medium, high, and social cost of greenhouse gas scenarios described above. The modeled allowance cost reflects analysis conducted by Vivid Economics for the Washington Department of Ecology and starts at $58 per ton in 2023.

Supply-Side Resources

Proxy resource costs and operating characteristics are generally unchanged from assumptions used in the 2023 IRP. However, in response to stakeholder comments, PacifiCorp incorporated a modified cost-escalation rate for geothermal resources based on the National Renewable Energy Laboratory's 2023 Annual Technology Baseline. Whereas geothermal costs were previously modeled as escalating at inflation, the updated escalation rate results in lower costs throughout the study horizon. As a result, geothermal joins wind, solar, and lithium-ion battery storage in using resource cost escalation rates that are lower than the standard estimate based on inflation, though near-term wind and solar costs are aligned with recent offers with bidders in PacifiCorp's 2020 All-Source Request for Proposals, from summer 2022. In conjunction with tax credits, this results in variation in costs over time, as presented in Figure 5.3.

Several modifications were made to clarify the assumptions within the supply-side resource table. Hydrogen resources were split out to report whether they use hydrogen on-site storage or pipeline supply. Inflation Reduction Act (IRA) credits were included in the 2023 IRP and have now been identified for each resource type within the supply-side table below for the 2023 IRP Update. Within the supply-side table detail, all costs remain in real levelized 2022 dollars. As in the 2023 IRP, near term resource selections in the 2023 IRP update are limited through 2028 to technology types and locations of pending requests that have received interconnection study results. Starting in 2029, proxy resources can be selected in any size and combination at any location, with hourly generation limited by available transmission. As an example, if a selected transmission upgrade allows for 400 additional megawatts of resources, the model is allowed to select 600 megawatts of wind resources, 300 megawatts of battery resources, 300 megawatts of solar resources, and 200 megawatts of gas peaking resources. This would cause the location to have 1400 megawatts of nameplate resources, of which only 400 megawatts could be generating into the system at any point in time. Any excess generation could flow into storage resources or would otherwise be curtailed.

Figure 5.3 – Inflation Reduction Act and Future Technology Costs



Natural Gas

In the 2023 IRP proxy natural gas plants were given an assumed economic life of 10 years, reflecting the risk that plants fueled by natural gas could have future policies limiting their effective use. In the 2023 IRP Update, given that new natural gas plants are assumed capable of converting to alternative fuels such as green hydrogen in the future, PacifiCorp is now modeling these resources using their full economic and technical lives. Manufacturers have confirmed this as a supportable assumption. The risk of early closures and derates due to emissions is mitigated by the ability to switch to non-emitting fueling in the future.

Peaking Type Resources

Related to the natural gas discussion, above, in the 2023 IRP new proxy peaking units were assumed to be non-emitting. In the 2023 IRP Update, peaking units will be selected on the basis of natural gas fueling assumptions but will have the ability to convert to hydrogen or other renewable fuel.

Demand Side Management

PacifiCorp evaluates new demand side management (DSM) opportunities, which includes both energy efficiency and demand response programs, as a resource that competes with traditional new generation and wholesale power market purchases when developing resource portfolios for the IRP. The optimal determination of DSM resources therefore results in the selection of cost-effective DSM as a core function of IRP modeling. As in the 2023 IRP, DSM for Washington in the 2023 IRP Update preferred portfolio reflects selections from the Washington compliance scenario, under SC-GHG price-policy assumptions. In the 2023 IRP Update, energy efficiency

shapes for heating and cooling measures have been updated to align with updated load, representing the relative effectiveness of these bundles to meet system need.

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Table 5.2 - 2023 IRP Update Supply Side Resources (2022$)

Information Presented is Illustrative

Description		Resource Characteristics				Costs				Operating Characteristics				Environmental			
Fuel	Resource	Elevation (AFSL)	Net Capacity (MW)	Commercial Operation Year	Design Life (yrs)	Base Capital ($/KW)	Demolition Cost ($/kW)	Var O&M ($/MWh)	Fixed O&M ($/KW-yr)	Average Full Load Heat Rate (HHV Btu/KWh)/Efficiency	EFOR (%)	POR (%)	Water Consumed (Gal/MWh)	SO2 (lbs/MMBtu)	NOx (lbs/MMBtu)	Hg (lbs/TBTu)	CO2 (lbs/MMBtu)
Natural Gas	SCCT Aero x4	0	229	2027	30	$ 1,530	$ 34.67	$ 0.28	$ 18.68	9241	0.7	2.0	23	0.0014	0.0910	0.2550	118.9000
Natural Gas	SCCT Frame "J" x1	0	354	2027	40	$ 814	$ 20.80	$ 2.32	$ 14.09	9073	5.6	7.2	0	0.0020	0.0570	0.2550	118.9000
Natural Gas	SCCT Frame "J" x1, 30H2 - onsite hydrogen production and liquified storage	0	337	2028	40	$ 3,932	$ 28.22	$ 2.44	$ 44.80	9191	5.6	7.2	122	0.0018	0.0550	0.1785	112.0000
Natural Gas	SCCT Frame "J" X1, 100H2 - onsite hydrogen production and liquified storage	0	362	2035	40	$ 6,588	$ 31.32	$ 2.23	$ 69.00	9489	5.6	7.2	406	0.0000	0.0655	0.0000	0.0000
Natural Gas	SCCT Frame "J" X1, 100H2 - pipeline Willamette Valley	0	362	2035	40	$ 930	$ 31.32	$ 2.23	$ 14.09	9489	5.6	7.2	406	0.0000	0.0655	0.0000	0.0000
Natural Gas	SCCT Frame "J" X1, 100H2 - pipeline McNary	0	362	2035	40	$ 930	$ 31.32	$ 2.23	$ 14.09	9489	5.6	7.2	406	0.0000	0.0655	0.0000	0.0000
Natural Gas	SCCT Frame "J" X1, 100H2, BF - onsite hydrogen production and liquified storage	0	362	2033	40	$ 5,894	$ 31.32	$ 2.27	$ 66.37	9489	5.6	7.2	406	0.0000	0.0655	0.0000	0.0000
Natural Gas	CCCT Dry "J", 1X1	0	548	2028	40	$ 1,361	$ 20.97	$ 1.61	$ 22.72	6227	5.6	7.2	8	0.0020	0.0076	0.2550	118.9000
Natural Gas	CCCT Dry "J", DF, 1x1	0	63	2028	40	$ -	$ -	$ 1.15	$ -	8726	5.6	7.2	8	0.0020	0.0076	0.2550	118.9000
Natural Gas	SCCT Aero x4	1,500	216	2027	30	$ 1,619	$ 45.80	$ 0.30	$ 19.77	9258	0.7	2.0	24	0.0014	0.0910	0.2550	118.9000
Natural Gas	SCCT Frame "J" x1	1,500	338	2027	40	$ 853	$ 28.29	$ 2.43	$ 14.76	9066	5.6	7.2	0	0.0020	0.0570	0.2550	118.9000
Natural Gas	SCCT Frame "J" x1, 30H2 - onsite hydrogen production and liquified storage	1,500	322	2028	40	$ 4,118	$ 37.95	$ 2.55	$ 46.92	9184	5.6	7.2	122	0.0018	0.0550	0.1785	113.0000
Natural Gas	SCCT Frame "J" X1, 100H2 - onsite hydrogen production and liquified storage	1,500	345	2035	40	$ 6,903	$ 41.21	$ 2.38	$ 73.77	9481	5.6	7.2	406	0.0000	0.0654	0.0000	0.0000
Natural Gas	SCCT Frame "J" X1, 100H2 - pipeline Southern OR	1,500	345	2035	40	$ 975	$ 41.21	$ 2.38	$ 14.76	9481	5.6	7.2	406	0.0000	0.0654	0.0000	0.0000
Natural Gas	SCCT Frame "J" X1, 100H2, BF - onsite hydrogen production and liquified storage	1,500	345	2033	40	$ 6,176	$ 41.21	$ 2.38	$ 69.54	9481	5.6	7.2	406	0.0000	0.0654	0.0000	0.0000
Natural Gas	CCCT Dry "J", 1X1	1,500	523	2028	40	$ 1,427	$ 27.74	$ 1.68	$ 23.81	6227	5.6	7.2	8	0.0020	0.0076	0.2550	118.9000
Natural Gas	CCCT Dry "J", DF, 1x1	1,500	63	2028	40	$ -	$ -	$ 1.15	$ -	8688	5.6	7.2	9	0.0020	0.0076	0.2550	118.9000
Natural Gas	SCCT Frame "J" x1, 30H2 - onsite hydrogen production and liquified storage	3,000	305	2027	40	$ 4,355	$ 37.87	$ 2.70	$ 49.63	9189	5.6	7.2	122	0.0018	0.0550	0.1785	113.0000
Natural Gas	SCCT Frame "J" X1, 100H2 - onsite hydrogen production and liquified storage	3,000	327	2034	40	$ 7,297	$ 42.56	$ 2.52	$ 77.98	9486	5.6	7.2	406	0.0000	0.0655	0.0000	0.0000
Natural Gas	SCCT Frame "J" X1, 100H2, BF - onsite hydrogen production and liquified storage	3,000	327	2034	40	$ 6,529	$ 42.56	$ 2.52	$ 73.52	9486	5.6	7.2	406	0.0000	0.0655	0.0000	0.0000
Natural Gas	CCCT Dry "J", 1X1	3,000	495	2027	40	$ 1,507	$ 27.37	$ 1.78	$ 25.15	6226	5.6	7.2	8	0.0020	0.0076	0.2550	118.9000
Natural Gas	CCCT Dry "J", DF, 1x1	3,000	63	2028	40	$ -	$ -	$ 1.15	$ -	8705	5.6	7.2	9	0.0020	0.0076	0.2550	118.9000
Natural Gas	SCCT Aero x4	5,050	190	2028	30	$ 1,844	$ 41.83	$ 0.34	$ 22.54	9326	0.7	2.0	28	0.0014	0.0914	0.2550	118.9000
Natural Gas	SCCT Frame "J" x1	5,050	296	2029	40	$ 971	$ 24.85	$ 2.78	$ 16.83	9080	5.6	7.2	0	0.0020	0.0571	0.2550	118.9000
Natural Gas	SCCT Frame "J" x1, 30H2 - onsite hydrogen production and liquified storage	5,050	282	2029	40	$ 4,696	$ 33.72	$ 2.91	$ 53.53	9197	5.6	7.2	122	0.0018	0.0550	0.1785	112.0000
Natural Gas	SCCT Frame "J" X1, 100H2 - onsite hydrogen production and liquified storage	5,050	303	2035	40	$ 7,869	$ 37.42	$ 2.72	$ 84.10	9493	5.6	7.2	406	0.0000	0.0655	0.0000	0.0000
Natural Gas	SCCT Frame "J" X1, 100H2 - pipeline Utah North	5,050	303	2035	40	$ 1,109	$ 37.42	$ 2.72	$ 16.83	9493	5.6	7.2	406	0.0000	0.0655	0.0000	0.0000
Natural Gas	SCCT Frame "J" X1, 100H2, BF - onsite hydrogen production and liquified storage	5,050	303	2035	40	$ 7,041	$ 37.42	$ 2.72	$ 79.29	9493	5.6	7.2	406	0.0000	0.0655	0.0000	0.0000
Natural Gas	SCCT Frame "J" X1, 100H2, BF - pipeline Dave Johnston	5,050	303	2035	40	$ 1,109	$ 37.42	$ 2.72	$ 16.83	9493	5.6	7.2	406	0.0000	0.0655	0.0000	0.0000
Natural Gas	SCCT Frame "J" X1, 100H2, BF - pipeline Hunter	5,050	303	2035	40	$ 1,109	$ 37.42	$ 2.72	$ 16.83	9493	5.6	7.2	406	0.0000	0.0655	0.0000	0.0000
Natural Gas	CCCT Dry "J", 1X1	5,050	459	2029	40	$ 1,625	$ 25.05	$ 1.92	$ 27.13	6234	5.6	7.2	8	0.0019	0.0076	0.2550	118.9000
Natural Gas	CCCT Dry "J", DF, 1x1	5,050	63	2029	40	$ -	$ -	$ 1.15	$ -	8652	5.6	7.2	9	0.0020	0.0076	0.2550	118.9000
Natural Gas	SCCT Aero x4	6,500	171	2028	30	$ 2,044	$ 49.31	$ 0.38	$ 24.98	9208	0.7	2.0	30	0.0000	0.0913	0.2550	118.9000
Natural Gas	SCCT Frame "J" x1	6,500	283	2028	40	$ 1,017	$ 28.64	$ 2.91	$ 17.63	9076	5.6	7.2	0	0.0000	0.0571	0.2550	118.9000
Natural Gas	SCCT Frame "J" X1, 100H2, BF - onsite hydrogen production and liquified storage	6,500	289	2034	40	$ 7,374	$ 44.16	$ 2.84	$ 17.63	9489	5.6	7.2	406	0.0000	0.0654	0.0000	0.0000
Natural Gas	SCCT Frame "J" X1, 100H2, BF - pipeline Naughton	6,500	289	2034	40	$ 1,162	$ 44.16	$ 2.84	$ 17.63	9489	5.6	7.2	406	0.0000	0.0654	0.0000	0.0000
Natural Gas	SCCT Frame "J" X1, 100H2, BF - pipeline Jim Bridger	6,500	289	2034	40	$ 1,162	$ 44.16	$ 2.84	$ 17.63	9489	5.6	7.2	406	0.0000	0.0654	0.0000	0.0000
Natural Gas	CCCT Dry "J", 1X1	6,500	437	2027	40	$ 1,704	$ 43.32	$ 2.01	$ 28.46	6241	5.6	7.2	8	0.0000	0.0076	0.2550	118.9000
Natural Gas	CCCT Dry "J", DF, 1x1	6,500	63	2027	40	$ -	$ -	$ 1.15	$ -	8590	5.6	7.2	9	0.0000	0.0076	0.2550	118.9000
Coal	PC CCUS Oxy-Combustion retrofit @ 100 MW pre-retrofit basis	5,000	-39	2028	30	$ 4,673	$ 37.00	$ 18.68	$ 54.24	18321	5	5.0	193	0.0040	0.0420	1.2000	6.2400
Coal	PC CCUS retrofit @ 330 MW pre-retrofit basis	6,500	-99	2028	20	$ 2,826	$ 37.00	$ 21.70	$ 32.71	15632	5	5.0	450	0.0050	0.0700	1.2000	20.5352
Coal	PC CCUS retrofit @ 700 MW pre-retrofit basis	6,500	-187	2028	20	$ 1,932	$ 37.00	$ 20.79	$ 18.04	14656	5	5.0	450	0.0050	0.0700	1.2000	20.5352
Storage	Li-Ion, 4-hour, 200 MW	N/A	200	2025	20	$ 1,827	$ 24.00	Included	$ 42.32	n/a	0	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Incremental, double energy capacity (L-ion, 4hr, 200MW)	N/A	200	2025	20	$ 1,495	$ 24.00	Included	$ 42.32	n/a	0	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Li-Ion, 4-hour, 500 MW	N/A	500	2025	20	$ 1,785	$ 24.00	Included	$ 41.36	n/a	0	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Incremental, double energy capacity (L-ion, 4hr, 500MW)	N/A	500	2025	20	$ 1,468	$ 24.00	Included	$ 41.36	n/a	0	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Li-Ion, 4-hour, 1000 MW	N/A	1,000	2025	20	$ 1,738	$ 24.00	Included	$ 40.31	n/a	0	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Incremental, double energy capacity (L-ion, 4hr, 1000MW)	N/A	1,000	2025	20	$ 1,430	$ 24.00	Included	$ 40.31	n/a	0	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Flow Battery, 4 hour, 200 MW	N/A	200	2025	25	$ 2,472	$ 34.00	$ 0.03	$ 64.27	n/a	0	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Incremental, double energy capacity (Flow, 4hr, 200MW)	N/A	200	2025	25	$ 2,071	$ 34.00	$ -	$ 7.00	n/a	0	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Flow Battery, 4 hour, 1000 MW	N/A	1,000	2025	25	$ 2,294	$ 32.00	$ 0.13	$ 54.86	n/a	0	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Incremental, double energy capacity (Flow, 4hr, 1000MW)	N/A	1,000	2025	25	$ 1,902	$ 32.00	$ -	$ 1.66	n/a	0	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Gravity Battery, 4 hour,	N/A	200	2025	50	$ 3,493	$ 0.30	Included	$ 80.97	n/a	0	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Incremental, double energy capacity (Gravity, 4hr, 200MW)	N/A	200	2025	50	$ 1,904	$ 0.30	Included	$ -	n/a	0	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Gravity Battery, 4 hour,	N/A	500	2025	50	$ 3,267	$ 0.24	Included	$ 75.75	n/a	0	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Incremental, double energy capacity (Gravity, 4hr, 500MW)	N/A	500	2025	50	$ 1,705	$ 0.24	Included	$ -	n/a	0	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Gravity Battery, 4 hour,	N/A	1,000	2025	50	$ 2,037	$ 0.18	Included	$ 47.25	n/a	0	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Incremental, double energy capacity (Gravity, 4hr, 1000MW)	N/A	1,000	2025	50	$ 993	$ 0.18	Included	$ -	n/a	0	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Adiabatic CAES, RESC, 125 MW, 1000 MWh	6,500	125	2026	30	$ 2,322	$ 49.31	$ 1.05	$ 16.91	n/a	0.011	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Adiabatic CAES, RESC, 125 MW, 1250 MWh	6,500	125	2026	30	$ 2,343	$ 49.31	$ 1.05	$ 16.95	n/a	0.011	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Adiabatic CAES, RESC, 125 MW, 1500 MWh	6,500	125	2027	30	$ 2,588	$ 49.31	$ 1.05	$ 16.99	n/a	0.011	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Adiabatic CAES, RESC, 125 MW, 2000 MWh	6,500	125	2027	30	$ 2,673	$ 49.31	$ 1.05	$ 17.07	n/a	0.011	0.0	n/a	0.0000	0.0000	0.0000	0.0000

Table 5.2 - 2023 IRP Update Supply Side Resources (2022 $) (Continued)

Information Presented is Illustrative

Description		Resource Characteristics				Costs				Operating Characteristics				Environmental			
Fuel	Resource	Elevation (AFSL)	Net Capacity (MW)	Commercial Operation Year	Design Life (yrs)	Base Capital ($/KW)	Demolition Cost ($/kW)	Var O&M ($/MWh)	Fixed O&M ($/KW-yr)	Average Full Load Heat Rate (HHV Btu/KWh)/Efficiency	EFOR (%)	POR (%)	Water Consumed (Gal/MWh)	SO2 (lbs/MMBtu)	NOx (lbs/MMBtu)	Hg (lbs/TBTu)	CO2 (lbs/MMBtu)
Storage	Adiabatic CAES, RESC, 125 MW, 3000 MWh	6,500	125	2027	30	$ 2,869	$ 49.31	$ 1.05	$ 17.23	n/a	0.0	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Adiabatic CAES, RESC, 125 MW, 6000 MWh	6,500	125	2029	30	$ 3,887	$ 49.31	$ 1.05	$ 17.71	n/a	0.0	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Adiabatic CAES, RESC, 250 MW, 4000 MWh	6,500	250	2028	30	$ 2,453	$ 49.31	$ 1.05	$ 12.65	n/a	0.011	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Adiabatic CAES, RESC, 250 MW, 6000 MWh	6,500	250	2029	30	$ 2,748	$ 49.31	$ 1.05	$ 12.81	n/a	0.011	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Adiabatic CAES, RESC, 250 MW, 12000 MWh	6,500	250	2032	30	$ 3,678	$ 49.31	$ 1.05	$ 13.29	n/a	0.011	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Adiabatic CAES, RESC, 500 MW, 4000 MWh	6,500	500	2028	30	$ 2,024	$ 49.31	$ 1.05	$ 10.28	n/a	0.011	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Adiabatic CAES, RESC, 500 MW, 5000 MWh	6,500	500	2028	30	$ 2,037	$ 49.31	$ 1.05	$ 10.32	n/a	0.011	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Adiabatic CAES, RESC, 500 MW, 6000 MWh	6,500	500	2029	30	$ 2,180	$ 49.31	$ 1.05	$ 10.36	n/a	0.011	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Adiabatic CAES, RESC, 500 MW, 8000 MWh	6,500	500	2030	30	$ 2,327	$ 49.31	$ 1.05	$ 10.44	n/a	0.011	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Adiabatic CAES, RESC, 500 MW, 12000 MWh	6,500	500	2032	30	$ 2,645	$ 49.31	$ 1.05	$ 10.60	n/a	0.011	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Adiabatic CAES, RESC, 500 MW, 24000 MWh	6,500	500	2035	30	$ 3,629	$ 49.31	$ 1.05	$ 11.08	n/a	0.011	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Pumped Hydro, Southern OR	N/A	400	2028	100	$ 4,303	$ 485.00	$ 0.51	$ 18.00	1	2	4.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Pumped Hydro, Portland North Coast	N/A	400	2028	100	$ 4,303	$ 485.00	$ 0.51	$ 18.00	1	2	4.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Pumped Hydro, Central WY	N/A	400	2028	100	$ 4,303	$ 485.00	$ 0.51	$ 18.00	1	2	4.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Pumped Hydro, Eastern WY	N/A	400	2028	100	$ 4,303	$ 485.00	$ 0.51	$ 18.00	1	2	4.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Pumped Hydro, Central UT	N/A	400	2028	100	$ 4,303	$ 485.00	$ 0.51	$ 18.00	1	2	4.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	100-hour Iron Air Battery, max CF: 17%	N/A	200	2025	20	$ 5,367	$ 160.00	Included	$ 20.77	0	0	0.0	0	0.0000	0.0000	0.0000	0.0000
Solar	Solar - Idaho Falls, ID, 20 MW, 26.1% CF	4,700	20	2025	25	$ 1,427	$ 29.40	$ -	$ 20.87	n/a	Included with CF	0.0	n/a	n/a	n/a	n/a	n/a
Solar	Solar - Lakeview, OR, 20 MW, 27.6% CF	4,800	20	2023	25	$ 1,527	$ 31.50	$ -	$ 20.87	n/a	Included with CF	0.0	n/a	n/a	n/a	n/a	n/a
Solar	Solar - Milford, UT, 20 MW, 30.2% CF	5,000	20	2023	25	$ 1,412	$ 29.10	$ -	$ 20.87	n/a	Included with CF	0.0	n/a	n/a	n/a	n/a	n/a
Solar	Solar - Milford, UT, 200 MW, 30.2% CF	5,000	200	2023	25	$ 1,140	$ 29.10	$ -	$ 20.87	n/a	Included with CF	0.0	n/a	n/a	n/a	n/a	n/a
Solar	Solar - Rock Springs, WY, 200 MW, 27.9% CF	6,400	200	2023	25	$ 1,187	$ 30.30	$ -	$ 20.87	n/a	Included with CF	0.0	n/a	n/a	n/a	n/a	n/a
Solar	Solar - Yakima, WA, 200 MW, 24.2% CF	1,000	200	2025	25	$ 1,211	$ 30.90	$ -	$ 20.87	n/a	Included with CF	0.0	n/a	n/a	n/a	n/a	n/a
Solar + Storage	Solar + Storage - Idaho Falls, ID, 200 MW, 26.1% CF + BESS: 100% pwr, 4 hours	4,700	200	2025	25	$ 2,879	$ 54.06	$ -	$ 63.19	1	Included with CF	0.0	n/a	n/a	n/a	n/a	n/a
Solar + Storage	Solar + Storage - Lakeview, OR, 200 MW, 27.6% CF + BESS: 100% pwr, 4 hours	4,800	200	2025	25	$ 2,864	$ 56.16	$ -	$ 63.19	1	Included with CF	0.0	n/a	n/a	n/a	n/a	n/a
Solar + Storage	Solar + Storage - Milford, UT, 200 MW, 30.2% CF + BESS: 100% pwr, 4 hours	5,000	200	2025	25	$ 2,881	$ 53.76	$ -	$ 63.19	1	Included with CF	0.0	n/a	n/a	n/a	n/a	n/a
Solar + Storage	Solar + Storage - Rock Springs, WY, 200 MW, 27.9% CF + BESS: 100% pwr, 4 hours	6,400	200	2025	25	$ 2,902	$ 54.96	$ -	$ 63.19	1	Included with CF	0.0	n/a	n/a	n/a	n/a	n/a
Solar + Storage	Solar + Storage - Yakima, WA, 200 MW, 24.2% CF + BESS: 100% pwr, 4 hours	1,000	200	2025	25	$ 2,977	$ 55.56	$ -	$ 63.19	1	Included with CF	0.0	n/a	n/a	n/a	n/a	n/a
Wind	Wind - Pocatello, ID, 20 MW, CF: 37.1%	4,500	20	2026	30	$ 2,161	$ 59.46	$ -	$ 43.00	n/a	Included with CF	0.0	n/a	n/a	n/a	n/a	n/a
Wind	Wind - Pocatello, ID, 200 MW, CF: 37.1%	4,500	200	2026	30	$ 1,597	$ 59.46	$ -	$ 43.00	n/a	Included with CF	0.0	n/a	n/a	n/a	n/a	n/a
Wind	Wind - Arlington, OR, 20 MW, CF: 37.1%	1,500	20	2026	30	$ 2,149	$ 59.46	$ -	$ 43.00	n/a	Included with CF	0.0	n/a	n/a	n/a	n/a	n/a
Wind	Wind - Arlington, OR, 200 MW, CF: 37.1%	1,500	200	2026	30	$ 1,567	$ 59.46	$ -	$ 43.00	n/a	Included with CF	0.0	n/a	n/a	n/a	n/a	n/a
Wind	Wind - Monticello, UT, 20 MW, CF: 29.5%	4,500	20	2026	30	$ 2,186	$ 59.46	$ -	$ 43.00	n/a	Included with CF	0.0	n/a	n/a	n/a	n/a	n/a
Wind	Wind - Monticello, UT, 200 MW, CF: 29.5%	4,500	200	2026	30	$ 1,626	$ 59.46	$ -	$ 43.00	n/a	Included with CF	0.0	n/a	n/a	n/a	n/a	n/a
Wind	Wind - Medicine Bow, WY, 20 MW, CF: 43.6%	6,500	20	2026	30	$ 2,129	$ 59.46	$ -	$ 43.00	n/a	Included with CF	0.0	n/a	n/a	n/a	n/a	n/a
Wind	Wind - Medicine Bow, WY, 200 MW, CF: 43.6%	6,500	200	2026	30	$ 1,568	$ 59.46	$ -	$ 43.00	n/a	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind	Wind - Goldendale, WA, 20 MW, CF: 37.1%	1,500	20	2026	30	$ 2,274	$ 59.46	$ -	$ 43.00	n/a	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind	Wind - Goldendale, WA, 200 MW, CF: 37.1%	1,500	200	2026	30	$ 1,660	$ 59.46	$ -	$ 43.00	n/a	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind	Wind - Offshore, Northern, CA, CF: 47.0%	0	200	2028	30	$ 4,636	$ 158.23	$ -	$ 103.00	n/a	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind	Wind -Offshore, Northern, CA, 1GW, CF: 47.0%	0	1,000	2028	30	$ 4,633	$ 158.23	$ -	$ 103.00	n/a	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind + Storage	Wind + Storage - Pocatello, ID, 200 MW, CF: 37.1% + BESS: 100% pwr, 4 hours	4,500	200	2026	30	$ 3,290	$ 83.46	$ -	$ 85.32	1	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind + Storage	Wind + Storage - Arlington, OR, 200 MW, CF: 37.1% + BESS: 100% pwr, 4 hours	1,500	200	2026	30	$ 3,166	$ 83.46	$ -	$ 85.32	1	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind + Storage	Wind + Storage - Monticello, UT, 200 MW, CF: 29.5% + BESS: 100% pwr, 4 hours	4,500	200	2026	30	$ 3,332	$ 83.46	$ -	$ 85.32	1	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind + Storage	Wind + Storage - Medicine Bow, WY, 200 MW, CF: 43.6% + BESS: 100% pwr, 4 hours	6,500	200	2026	30	$ 3,252	$ 83.46	$ -	$ 85.32	1	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind + Storage	Wind + Storage - Goldendale, WA, 200 MW, CF: 37.1% + BESS: 100% pwr, 4 hours	1,500	200	2026	30	$ 3,389	$ 83.46	$ -	$ 85.32	1	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind + Storage	Wind + Storage - Offshore, Northern, CA, CF: 47.0% + BESS: 100% pwr, 4 hours	0	200	2028	30	$ 6,545	$ 182.23	$ -	$ 145.32	85%	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Solar+Wind+Storage	Idaho Falls, ID Solar + Wind + BESS: 100% pwr, 4 hours	4,700	200	2026	25	$ 6,194	$ 113.52	$ -	$ 148.51	85%	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Solar+Wind+Storage	Lakeview, OR Solar + Wind + BESS: 100% pwr, 4 hours	4,800	200	2026	25	$ 6,052	$ 115.62	$ -	$ 148.51	85%	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Solar+Wind+Storage	Milford, UT Solar + Wind + BESS: 100% pwr, 4 hours	5,000	200	2026	25	$ 6,238	$ 113.22	$ -	$ 148.51	85%	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Solar+Wind+Storage	Rock Springs, WY Solar + Wind + BESS: 100% pwr, 4 hours	6,400	200	2026	25	$ 5,703	$ 114.42	$ -	$ 148.51	85%	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Solar+Wind+Storage	Yakima, WA Solar + Wind + BESS: 100% pwr, 4 hours	1,000	200	2026	25	$ 5,898	$ 115.02	$ -	$ 148.51	85%	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Geothermal	Geothermal - Dual Flash Expansion of Blundell Plant	4,500	200	2026	40	$ 3,835	$ 117.00	$ -	$ 115.00	n/a	2.5	2.5	1,453.4	n/a	n/a	n/a	n/a
Geothermal	Geothermal - Greenfield Binary Plant	4,500	200	2026	40	$ 5,568	$ 117.00	$ -	$ 115.00	n/a	2.5	2.5	1,453.4	n/a	n/a	n/a	n/a
Nuclear	Nuclear - Advanced LWR, 600 MW Site	N/A	600	2032	60	$ 8,416	$ 721.53	$ -	$ 170.60	N/A	1.0	4.0	767.2	0.0000	0.0000	0.0000	0.0000
Nuclear	Nuclear - Advanced LWR, 1200 MW Site	N/A	1,200	2032	60	$ 7,272	$ 721.53	$ -	$ 152.29	N/A	1.0	4.0	767.2	0.0000	0.0000	0.0000	0.0000
Nuclear	Advanced Nuclear Reactor (AR), dual unit, with Thermal Storage (1000 Mwe interconnection with 1705 MWh Storage, 638 MW initial base generation)	N/A	638	2032	60	$ 8,772	$ 721.53	$ -	$ 472.81	N/A	3.0	5.0	767.2	0.0000	0.0000	0.0000	0.0000
Nuclear	Advanced Nuclear Reactor (AR) with improved fuel (1000 Mwe interconnection with 1705 MWh Storage, 690 MW base generation)	N/A	690	2038	Aligned with original plant	$ 8,772	$ 721.53	$ -	$ 286.40	N/A	2.0	4.0	767.2	0.0000	0.0000	0.0000	0.0000

Iron Air battery presented with most recent costs that have not flowed into the PLEXOS model

Table 5.3 – 2023 IRP Update Supply Side Resources (2022 $)

Information Presented is Illustrative

Supply Side Resource Options Mid-Calendar Year 2022 Dollars ($)			Capital Cost $/kW				Fixed Cost					
							Fixed O&M $/kW-Yr					
Resource Description	Modeled IRP	Elevation (AFSL)	Total Capital Cost 1/	Demolition Cost	Payment Factor 1/	Annual Payment ($/kW-Yr)	O&M 1/	Capitalized Premium	O&M Capitalized 1/	Gas Transportation 1/	Total	Total Fixed ($/kW-Yr)
SCCT Aero x4	No	0	$1,530	$35	7.140%	$111.68	$18.68	0.000%	$0.00	$31.59	$50.27	$161.95
SCCT Frame "J" x1	No	0	$814	$21	6.456%	$53.89	$14.09	0.000%	$0.00	$31.02	$45.11	$99.00
SCCT Frame "J" x1, 30H2 - onsite hydrogen production and liquified storage	No	0	$3,932	$28	6.456%	$255.67	$44.80	0.000%	$0.00	$31.42	$76.22	$331.89
SCCT Frame "J" X1, 100H2 - onsite hydrogen production and liquified storage	No	0	$6,588	$31	6.456%	$427.34	$69.00	0.000%	$0.00	$32.44	$101.44	$528.77
SCCT Frame "J" X1, 100H2 - pipeline Willamette Valley	Yes	0	$930	$31	6.456%	$62.04	$14.09	0.000%	$0.00	$119.30	$133.39	$195.43
SCCT Frame "J" X1, 100H2 - pipeline McNary	Yes	0	$930	$31	6.456%	$62.04	$14.09	0.000%	$0.00	$266.68	$280.77	$342.81
SCCT Frame "J" X1, 100H2, BF - onsite hydrogen production and liquified storage	No	0	$5,894	$31	6.456%	$382.59	$66.37	0.000%	$0.00	$32.44	$98.80	$481.39
CCCT Dry "J", 1X1	No	0	$1,361	$21	6.609%	$91.33	$22.72	2.616%	$0.59	$21.29	$44.60	$135.93
CCCT Dry "J", DF, 1x1	No	0	$0	$0	6.609%	$0.00	$0.00	2.616%	$0.00	$29.83	$29.83	$29.83
SCCT Aero x4	No	1,500	$1,619	$46	7.140%	$118.87	$19.77	0.000%	$0.00	$31.65	$51.42	$170.29
SCCT Frame "J" x1	No	1,500	$853	$28	6.456%	$56.89	$14.76	0.000%	$0.00	$30.99	$45.75	$102.64
SCCT Frame "J" x1, 30H2 - onsite hydrogen production and liquified storage	No	1,500	$4,118	$38	6.456%	$268.33	$46.92	0.000%	$0.00	$31.39	$78.32	$346.64
SCCT Frame "J" X1, 100H2 - onsite hydrogen production and liquified storage	No	1,500	$6,903	$41	6.456%	$448.32	$73.77	0.000%	$0.00	$32.41	$106.17	$554.49
SCCT Frame "J" X1, 100H2 - pipeline Southern OR	Yes	1,500	$975	$41	6.456%	$65.59	$14.76	0.000%	$0.00	$119.19	$133.96	$199.54
SCCT Frame "J" X1, 100H2, BF - onsite hydrogen production and liquified storage	No	1,500	$6,176	$41	6.456%	$401.43	$69.54	0.000%	$0.00	$32.41	$101.95	$503.38
CCCT Dry "J", 1X1	No	1,500	$1,427	$28	6.609%	$96.11	$23.81	2.616%	$0.62	$21.29	$45.72	$141.84
CCCT Dry "J", DF, 1x1	No	1,500	$0	$0	6.609%	$0.00	$0.00	2.616%	$0.00	$29.70	$29.70	$29.70
SCCT Aero x4	No	3,000	$1,712	$46	7.140%	$125.56	$20.92	0.000%	$0.00	$14.21	$35.12	$160.69
SCCT Frame "J" x1	No	3,000	$901	$29	6.456%	$60.06	$15.61	0.000%	$0.00	$13.88	$29.48	$89.54
SCCT Frame "J" x1, 30H2 - onsite hydrogen production and liquified storage	No	3,000	$4,355	$38	6.456%	$283.62	$49.63	0.000%	$0.00	$14.06	$63.68	$347.31
SCCT Frame "J" X1, 100H2 - onsite hydrogen production and liquified storage	No	3,000	$7,297	$43	6.456%	$473.86	$77.98	0.000%	$0.00	$14.51	$92.49	$566.35
SCCT Frame "J" X1, 100H2, BF - onsite hydrogen production and liquified storage	No	3,000	$6,529	$43	6.456%	$424.29	$73.52	0.000%	$0.00	$14.51	$88.03	$512.32
CCCT Dry "J", 1X1	No	3,000	$1,507	$27	6.609%	$101.38	$25.15	2.616%	$0.66	$9.52	$35.34	$136.71
CCCT Dry "J", DF, 1x1	No	3,000	$0	$0	6.609%	$0.00	$0.00	2.616%	$0.00	$13.32	$13.32	$13.32
SCCT Aero x4	Yes	5,050	$1,844	$42	7.140%	$134.64	$22.54	0.000%	$0.00	$14.20	$36.74	$171.39
SCCT Frame "J" x1	Yes	5,050	$971	$25	6.456%	$64.31	$16.83	0.000%	$0.00	$13.83	$30.66	$94.97
SCCT Frame "J" x1, 30H2 - onsite hydrogen production and liquified storage	No	5,050	$4,696	$34	6.456%	$305.37	$53.53	0.000%	$0.00	$14.01	$67.53	$372.90
SCCT Frame "J" X1, 100H2 - onsite hydrogen production and liquified storage	Yes	5,050	$7,869	$37	6.456%	$510.43	$84.10	0.000%	$0.00	$14.46	$98.56	$608.99
SCCT Frame "J" X1, 100H2 - pipeline Utah North	Yes	5,050	$1,109	$37	6.456%	$74.03	$16.83	0.000%	$0.00	$118.83	$135.66	$209.69
SCCT Frame "J" X1, 100H2, BF - onsite hydrogen production and liquified storage	No	5,050	$7,041	$37	6.456%	$456.98	$79.29	0.000%	$0.00	$14.46	$93.74	$550.72
SCCT Frame "J" X1, 100H2, BF - pipeline Dave Johnston	Yes	5,050	$1,109	$37	6.456%	$74.03	$16.83	0.000%	$0.00	$209.67	$226.51	$300.54
SCCT Frame "J" X1, 100H2, BF - pipeline Hunter	Yes	5,050	$1,109	$37	6.456%	$74.03	$16.83	0.000%	$0.00	$39.61	$56.44	$130.47
CCCT Dry "J", 1X1	Yes	5,050	$1,625	$25	6.609%	$109.01	$27.13	2.616%	$0.71	$9.49	$37.34	$146.35
CCCT Dry "J", DF, 1x1	Yes	5,050	$0	$0	6.609%	$0.00	$0.00	2.616%	$0.00	$13.18	$13.18	$13.18
SCCT Aero x4	Yes	6,500	$2,044	$49	7.140%	$149.43	$24.98	0.000%	$0.00	$24.74	$49.73	$199.16
SCCT Frame "J" x1	Yes	6,500	$1,017	$29	6.456%	$67.52	$17.63	0.000%	$0.00	$24.39	$42.02	$109.53
SCCT Frame "J" x1, 30H2 - onsite hydrogen production and liquified storage	No	6,500	$4,918	$40	6.456%	$320.07	$56.05	0.000%	$0.00	$24.70	$80.76	$400.83
SCCT Frame "J" X1, 100H2 - onsite hydrogen production and liquified storage	Yes	6,500	$8,241	$44	6.456%	$534.94	$88.09	0.000%	$0.00	$25.50	$113.59	$648.53
SCCT Frame "J" X1, 100H2, BF - onsite hydrogen production and liquified storage	No	6,500	$7,374	$44	6.456%	$479	$83.04	0.000%	$0.00	$25.50	$108.54	$587.50
SCCT Frame "J" X1, 100H2, BF - pipeline Naughton	Yes	6,500	$1,162	$44	6.456%	$77.86	$17.63	0.000%	$0.00	$118.77	$136.40	$214.26
SCCT Frame "J" X1, 100H2, BF - pipeline Jim Bridger	Yes	6,500	$1,162	$44	6.456%	$77.86	$17.63	0.000%	$0.00	$175.80	$193.43	$271.30
CCCT Dry "J", 1X1	Yes	6,500	$1,704	$43	6.609%	$115	$28.46	2.616%	$0.74	$16.77	$45.98	$161.46
CCCT Dry "J", DF, 1x1	Yes	6,500	$0	$0	6.609%	$0	$0.00	2.616%	$0.00	$23.08	$23.08	$23.08

Table 5.3 – 2023 IRP Update Supply Side Resources (2022 $) (Continued)

Information Presented is Illustrative

Supply Side Resource Options Mid-Calendar Year 2022 Dollars ($)			Capital Cost $/kW				Fixed Cost					
							Fixed O&M $/kW-Yr					
Resource Description	Modeled IRP	Elevation (AFSL)	Total Capital Cost 1/	Demolition Cost	Payment Factor 1/	Annual Payment ($/kW-Yr)	O&M 1/	Capitalized Premium	O&M Capitalized 1/	Gas Transportation 1/	Total	Total Fixed ($/kW-Yr)
PC CCUS Oxy-Combustion retrofit @ 100 MW pre-retrofit basis	Yes	5,000	$4,673	$37	7.289%	$343.30	$54.24	5.541%	$3.01	$0.00	$57.25	$400.54
PC CCUS retrofit @ 330 MW pre-retrofit basis	Yes	6,500	$2,826	$37	8.887%	$254.47	$32.71	5.541%	$1.81	$0.00	$34.52	$288.99
PC CCUS retrofit @ 700 MW pre-retrofit basis	Yes	6,500	$1,932	$37	8.903%	$175.28	$18.04	5.541%	$1.00	$0.00	$19.04	$194.32
Li-Ion, 4-hour, 200 MW	No	N/A	$1,827	$24	8.405%	$155.59	$42.32	0.000%	$0.00	$0.00	$42.32	$197.91
Incremental, double energy capacity (L-ion, 4hr, 200MW)	No	N/A	$1,495	$24	8.405%	$127.65	$42.32	0.000%	$0.00	$0.00	$42.32	$169.97
Li-Ion, 4-hour, 500 MW	Yes	N/A	$1,785	$24	8.405%	$152.01	$41.36	0.000%	$0.00	$0.00	$41.36	$193.37
Incremental, double energy capacity (L-ion, 4hr, 500MW)	Yes	N/A	$1,468	$24	8.405%	$125.39	$41.36	0.000%	$0.00	$0.00	$41.36	$166.75
Li-Ion, 4-hour, 1000 MW	No	N/A	$1,738	$24	8.405%	$148.12	$40.31	0.000%	$0.00	$0.00	$40.31	$188.43
Incremental, double energy capacity (L-ion, 4hr, 1000MW)	No	N/A	$1,430	$24	8.405%	$122.21	$40.31	0.000%	$0.00	$0.00	$40.31	$162.52
Flow Battery, 4 hour, 200 MW	Yes	N/A	$2,472	$34	8.405%	$210.62	$64.27	0.000%	$0.00	$0.00	$64.27	$274.89
Incremental, double energy capacity (Flow, 4hr, 200MW)	Yes	N/A	$2,071	$34	8.405%	$176.94	$7.00	0.000%	$0.00	$0.00	$7.00	$183.94
Flow Battery, 4 hour, 1000 MW	No	N/A	$2,294	$32	8.405%	$195.51	$54.86	0.000%	$0.00	$0.00	$54.86	$250.38
Incremental, double energy capacity (Flow, 4hr, 1000MW)	Yes	N/A	$1,902	$32	8.405%	$162.56	$1.66	0.000%	$0.00	$0.00	$1.66	$164.22
Gravity Battery, 4 hour,	Yes	N/A	$3,493	$0	8.405%	$293.64	$80.97	0.000%	$0.00	$0.00	$80.97	$374.61
Incremental, double energy capacity (Gravity, 4hr, 200MW)	Yes	N/A	$1,904	$0	8.405%	$160.09	$0.00	0.000%	$0.00	$0.00	$0.00	$160.09
Gravity Battery, 4 hour,	Yes	N/A	$3,267	$0	8.405%	$274.61	$75.75	0.000%	$0.00	$0.00	$75.75	$350.36
Incremental, double energy capacity (Gravity, 4hr, 500MW)	Yes	N/A	$1,705	$0	8.405%	$143.32	$0.00	0.000%	$0.00	$0.00	$0.00	$143.32
Gravity Battery, 4 hour,	Yes	N/A	$2,037	$0	8.405%	$171.26	$47.25	0.000%	$0.00	$0.00	$47.25	$218.51
Incremental, double energy capacity (Gravity, 4hr, 1000MW)	No	N/A	$993	$0	8.405%	$83.51	$0.00	0.000%	$0.00	$0.00	$0.00	$83.51
Adiabatic CAES, RESC, 125 MW, 1000 MWh	No	6,500	$2,322	$49	6.804%	$161.34	$16.91	5.480%	$0.93	$0.00	$17.84	$179.17
Adiabatic CAES, RESC, 125 MW, 1250 MWh	No	6,500	$2,343	$49	6.804%	$162.80	$16.95	5.480%	$0.93	$0.00	$17.88	$180.68
Adiabatic CAES, RESC, 125 MW, 1500 MWh	No	6,500	$2,588	$49	6.804%	$179.44	$16.99	5.480%	$0.93	$0.00	$17.92	$197.36
Adiabatic CAES, RESC, 125 MW, 2000 MWh	No	6,500	$2,673	$49	6.804%	$185.25	$17.07	5.480%	$0.94	$0.00	$18.01	$203.26
Adiabatic CAES, RESC, 125 MW, 3000 MWh	No	6,500	$2,869	$49	6.804%	$198.54	$17.23	5.480%	$0.94	$0.00	$18.18	$216.72
Adiabatic CAES, RESC, 125 MW, 6000 MWh	No	6,500	$3,887	$49	6.804%	$267.81	$17.71	5.480%	$0.97	$0.00	$18.68	$286.50
Adiabatic CAES, RESC, 250 MW, 4000 MWh	No	6,500	$2,453	$49	6.804%	$170.27	$12.65	5.480%	$0.69	$0.00	$13.35	$183.62
Adiabatic CAES, RESC, 250 MW, 6000 MWh	No	6,500	$2,748	$49	6.804%	$190.34	$12.81	5.480%	$0.70	$0.00	$13.52	$203.86
Adiabatic CAES, RESC, 250 MW, 12000 MWh	No	6,500	$3,678	$49	6.804%	$253.64	$13.29	5.480%	$0.73	$0.00	$14.02	$267.66
Adiabatic CAES, RESC, 500 MW, 4000 MWh	Yes	6,500	$2,024	$49	6.804%	$141.05	$10.28	5.480%	$0.56	$0.00	$10.85	$151.90
Adiabatic CAES, RESC, 500 MW, 5000 MWh	No	6,500	$2,037	$49	6.804%	$141.95	$10.32	5.480%	$0.57	$0.00	$10.89	$152.84
Adiabatic CAES, RESC, 500 MW, 6000 MWh	Yes	6,500	$2,180	$49	6.804%	$151.68	$10.36	5.480%	$0.57	$0.00	$10.93	$162.61

Table 5.3 – 2023 IRP Update Supply Side Resources (2022 $) (Continued)

Information Presented is Illustrative

Supply Side Resource Options Mid-Calendar Year 2022 Dollars ($)			Capital Cost $/kW				Fixed Cost					
							Fixed O&M $/kW-Yr					
Resource Description	Modeled IRP	Elevation (AFSL)	Total Capital Cost 1/	Demolition Cost	Payment Factor 1/	Annual Payment ($/kW-Yr)	O&M 1/	Capitalized Premium	O&M Capitalized 1/	Gas Transportation 1/	Total	Total Fixed ($/kW-Yr)
Adiabatic CAES, RESC, 500 MW, 8000 MWh	No	6,500	$2,327	$49	6.804%	$161.70	$10.44	5.480%	$0.57	$0.00	$11.02	$172.71
Adiabatic CAES, RESC, 500 MW, 12000 MWh	No	6,500	$2,645	$49	6.804%	$183.31	$10.60	5.480%	$0.58	$0.00	$11.19	$194.49
Adiabatic CAES, RESC, 500 MW, 24000 MWh	No	6,500	$3,629	$49	6.804%	$250.29	$11.08	5.480%	$0.61	$0.00	$11.69	$261.98
Pumped Hydro, Southern OR	Yes	N/A	$4,303	$485	5.567%	$266.55	$18.00	2.617%	$0.47	$0.00	$18.47	$285.02
Pumped Hydro, Portland North Coast	Yes	N/A	$4,303	$485	5.567%	$266.55	$18.00	2.617%	$0.47	$0.00	$18.47	$285.02
Pumped Hydro, Central WY	Yes	N/A	$4,303	$485	5.567%	$266.55	$18.00	2.617%	$0.47	$0.00	$18.47	$285.02
Pumped Hydro, Eastern WY	Yes	N/A	$4,303	$485	5.567%	$266.55	$18.00	2.617%	$0.47	$0.00	$18.47	$285.02
Pumped Hydro, Central UT	Yes	N/A	$4,303	$485	5.567%	$266.55	$18.00	2.617%	$0.47	$0.00	$18.47	$285.02
100-hour Iron Air Battery, max CF: 17%	Yes	N/A	$5,367	$160	8.405%	$464.51	$20.77	0.000%	$0.00	$0.00	$20.77	$485.27
Solar - Idaho Falls, ID, 20 MW, 26.1% CF	Yes	4,700	$1,427	$29	7.209%	$104.97	$20.87	1.370%	$0.29	$0.00	$21.16	$126.12
Solar - Lakeview, OR, 20 MW, 27.6% CF	Yes	4,800	$1,527	$32	7.209%	$112.33	$20.87	1.370%	$0.29	$0.00	$21.16	$133.48
Solar - Milford, UT, 20 MW, 30.2% CF	Yes	5,000	$1,412	$29	7.209%	$103.91	$20.87	1.370%	$0.29	$0.00	$21.16	$125.07
Solar - Milford, UT, 200 MW, 30.2% CF	Yes	5,000	$1,140	$29	7.209%	$84.31	$20.87	1.370%	$0.29	$0.00	$21.16	$105.47
Solar - Rock Springs, WY, 200 MW, 27.9% CF	Yes	6,400	$1,187	$30	7.209%	$87.78	$20.87	1.370%	$0.29	$0.00	$21.16	$108.94
Solar - Yakima, WA, 200 MW, 24.2% CF	Yes	1,000	$1,211	$31	7.209%	$89.51	$20.87	1.370%	$0.29	$0.00	$21.16	$110.67
Solar + Storage - Idaho Falls, ID, 200 MW, 26.1% CF + BESS: 100% pwr, 4 hours	No	4,700	$2,879	$54	7.209%	$211.42	$63.19	1.370%	$0.87	$0.00	$64.06	$275.48
Solar + Storage - Lakeview, OR, 200 MW, 27.6% CF + BESS: 100% pwr, 4 hours	No	4,800	$2,864	$56	7.209%	$210.50	$63.19	1.370%	$0.87	$0.00	$64.06	$274.55
Solar + Storage - Milford, UT, 200 MW, 30.2% CF + BESS: 100% pwr, 4 hours	No	5,000	$2,881	$54	7.209%	$211.55	$63.19	1.370%	$0.87	$0.00	$64.06	$275.61
Solar + Storage - Rock Springs, WY, 200 MW, 27.9% CF + BESS: 100% pwr, 4 hours	No	6,400	$2,902	$55	7.209%	$213.18	$63.19	1.370%	$0.87	$0.00	$64.06	$277.23
Solar + Storage - Yakima, WA, 200 MW, 24.2% CF + BESS: 100% pwr, 4 hours	No	1,000	$2,977	$56	7.209%	$218.63	$63.19	1.370%	$0.87	$0.00	$64.06	$282.69
Wind - Pocatello, ID, 20 MW, CF: 37.1%	Yes	4,500	$2,161	$59	6.657%	$147.82	$43.00	4.392%	$1.89	$0.00	$44.89	$192.71
Wind - Pocatello, ID, 200 MW, CF: 37.1%	Yes	4,500	$1,597	$59	6.657%	$110.25	$43.00	4.392%	$1.89	$0.00	$44.89	$155.14
Wind - Arlington, OR, 20 MW, CF: 37.1%	Yes	1,500	$2,149	$59	6.657%	$147.04	$43.00	4.392%	$1.89	$0.00	$44.89	$191.92
Wind - Arlington, OR, 200 MW, CF: 37.1%	Yes	1,500	$1,567	$59	6.657%	$108.27	$43.00	4.392%	$1.89	$0.00	$44.89	$153.16
Wind - Monticello, UT, 20 MW, CF: 29.5%	Yes	4,500	$2,186	$59	6.657%	$149.48	$43.00	4.392%	$1.89	$0.00	$44.89	$194.37
Wind - Monticello, UT, 200 MW, CF: 29.5%	Yes	4,500	$1,626	$59	6.657%	$112.20	$43.00	4.392%	$1.89	$0.00	$44.89	$157.09
Wind - Medicine Bow, WY, 20 MW, CF: 43.6%	Yes	6,500	$2,129	$59	6.657%	$145.71	$43.00	4.392%	$1.89	$0.00	$44.89	$190.60
Wind - Medicine Bow, WY, 200 MW, CF: 43.6%	Yes	6,500	$1,568	$59	6.657%	$108.31	$43.00	4.392%	$1.89	$0.00	$44.89	$153.20
Wind - Goldendale, WA, 20 MW, CF: 37.1%	Yes	1,500	$2,274	$59	6.657%	$155.32	$43.00	4.392%	$1.89	$0.00	$44.89	$200.21
Wind - Goldendale, WA, 200 MW, CF: 37.1%	Yes	1,500	$1,660	$59	6.657%	$114.49	$43.00	4.392%	$1.89	$0.00	$44.89	$159.38
Wind - Offshore, Northern, CA, CF: 47.0%	Yes	0	$4,636	$158	6.657%	$319.13	$103.00	4.392%	$4.52	$0.00	$107.52	$426.66
Wind -Offshore, Northern, CA, 1GW, CF: 47.0%	Yes	0	$4,633	$158	6.657%	$318.98	$103.00	4.392%	$4.52	$0.00	$107.52	$426.50
Wind + Storage - Pocatello, ID, 200 MW, CF: 37.1% + BESS: 100% pwr, 4 hours	No	4,500	$3,290	$83	6.657%	$224.60	$85.32	4.392%	$3.75	$0.00	$89.07	$313.66
Wind + Storage - Arlington, OR, 200 MW, CF: 37.1% + BESS: 100% pwr, 4 hours	No	1,500	$3,166	$83	6.657%	$216.30	$85.32	4.392%	$3.75	$0.00	$89.07	$305.36
Wind + Storage - Monticello, UT, 200 MW, CF: 29.5% + BESS: 100% pwr, 4 hours	No	4,500	$3,332	$83	6.657%	$227.34	$85.32	4.392%	$3.75	$0.00	$89.07	$316.40
Wind + Storage - Medicine Bow, WY, 200 MW, CF: 43.6% + BESS: 100% pwr, 4 hours	No	6,500	$3,252	$83	6.657%	$222.05	$85.32	4.392%	$3.75	$0.00	$89.07	$311.12
Wind + Storage - Goldendale, WA, 200 MW, CF: 37.1% + BESS: 100% pwr, 4 hours	No	1,500	$3,389	$83	6.657%	$231.15	$85.32	4.392%	$3.75	$0.00	$89.07	$320.21
Wind + Storage - Offshore, Northern, CA, CF: 47.0% + BESS: 100% pwr, 4 hours	No	0	$6,545	$182	6.657%	$447.82	$145.32	4.392%	$6.38	$0.00	$151.70	$599.52
Idaho Falls, ID Solar + Wind + BESS: 100% pwr, 4 hours	No	4,700	$6,194	$114	6.657%	$419.87	$148.51	4.392%	$6.52	$0.00	$155.03	$574.90
Lakeview, OR Solar + Wind + BESS: 100% pwr, 4 hours	No	4,800	$6,052	$116	6.657%	$410.55	$148.51	4.392%	$6.52	$0.00	$155.03	$565.58
Milford, UT Solar + Wind + BESS: 100% pwr, 4 hours	No	5,000	$6,238	$113	6.657%	$422.78	$148.51	4.392%	$6.52	$0.00	$155.03	$577.81
Rock Springs, WY Solar + Wind + BESS: 100% pwr, 4 hours	No	6,400	$5,703	$114	6.657%	$387.27	$148.51	4.392%	$6.52	$0.00	$155.03	$542.30
Yakima, WA Solar + Wind + BESS: 100% pwr, 4 hours	No	1,000	$5,898	$115	6.657%	$400.27	$148.51	4.392%	$6.52	$0.00	$155.03	$555.30
Geothermal - Dual Flash Expansion of Blundell Plant	Yes	4,500	$3,835	$117	6.015%	$237.74	$115.00	0.872%	$1.00	$0.00	$116.00	$353.74
Geothermal - Greenfield Binary Plant	Yes	4,500	$5,568	$117	6.015%	$341.93	$115.00	0.872%	$1.00	$0.00	$116.00	$457.93
Nuclear - Advanced LWR, 600 MW Site	Yes	N/A	$8,416	$722	5.846%	$534.16	$170.60	9.424%	$16.08	$0.00	$186.68	$720.83
Nuclear - Advanced LWR, 1200 MW Site	Yes	N/A	$7,272	$722	5.846%	$467.32	$152.29	9.424%	$14.35	$0.00	$166.64	$633.97
Advanced Nuclear Reactor (AR), dual unit, with Thermal Storage (1000 Mwe interconnection with 1705 MWh Storage, 638 MW initial base generation)	Yes	N/A	$8,772	$722	5.846%	$554.99	$472.81	9.424%	$44.56	$0.00	$517.36	$1,072.36
Advanced Nuclear Reactor (AR) with improved fuel (1000 Mwe interconnection with 1705 MWh Storage, 690 MW base generation)	Yes	N/A	$8,772	$722	5.846%	$554.99	$286.40	9.424%	$26.99	$0.00	$313.39	$868.39

1/ Input into IRP SO and PAR Model

Results presented without credits

Information Presented is Illustrative

CCUS costs are incremental and include envirnomental upgrade costs but are missing underlying coal unit costs

Table 5.4 – 2023 IRP Update Supply Side Resources (2022 $)

Information Presented is Illustrative

Supply Side Resource Options Mid-Calendar Year 2022 Dollars ($)		Convert to $/MWh			Levelized Fuel							Credits		$/MWh
Resource Description	Elevation (AFSL)	Capacity Factor 2/	Total Fixed ($/MWh)	Storage Efficiency	$/mmBtu	$/MWh	O&M 1/	Capitalized Premium	O&M Capitalized 1/	Integration Cost 1/	Total Resource Cost	PTC Tax Credits / ITC (Solar Only) / 45Q Tax Credits (CCUS Only)	PTC Tax Credits / ITC (Solar Only) / 45Q Tax Credits (CCUS Only)	Total Resource Cost - with PTC / ITC / 45Q Credits
SCCT Aero x4	0	33%	$56.02	N/A	$ 4.46	$ 41.26	$ 0.28	14.14%	$ 0.04	$ -	$97.60	$ -	-	$97.60
SCCT Frame "J" x1	0	33%	$34.25	N/A	$ 4.46	$ 40.51	$ 2.32	14.14%	$ 0.33	$ -	$77.41	$ -	-	$77.41
SCCT Frame "J" x1, 30H2 - onsite hydrogen production and liquified storage	0	33%	$114.81	N/A	$ 5.24	$ 48.14	$ 2.44	14.14%	$ 0.34	$ -	$165.73	$ -	-	$165.73
SCCT Frame "J" X1, 100H2 - onsite hydrogen production and liquified storage	0	33%	$182.92	N/A	$ 7.04	$ 66.82	$ 2.23	14.14%	$ 0.32	$ -	$252.28	$ (29.18)	ITC	$223.11
SCCT Frame "J" X1, 100H2 - pipeline Willamette Valley	0	33%	$67.60	N/A	$ 7.04	$ 66.82	$ 2.23	14.14%	$ 0.32	$ -	$136.97	$ (4.12)	ITC	$132.85
SCCT Frame "J" X1, 100H2 - pipeline McNary	0	33%	$118.59	N/A	$ 7.04	$ 66.82	$ 2.23	14.14%	$ 0.32	$ -	$187.95	$ (4.12)	ITC	$183.83
SCCT Frame "J" X1, 100H2, BF - onsite hydrogen production and liquified storage	0	33%	$166.52	N/A	$ 7.04	$ 66.82	$ 2.27	14.14%	$ 0.32	$ -	$235.94	$ (26.11)	ITC	$209.84
CCCT Dry "J", 1X1	0	78%	$19.89	N/A	$ 4.46	$ 27.80	$ 1.61	14.39%	$ 0.23	$ -	$49.53	$ -	-	$49.53
CCCT Dry "J", DF, 1x1	0	12%	$28.38	N/A	$ 4.46	$ 38.96	$ 1.15	14.39%	$ 0.16	$ -	$68.65	$ -	-	$68.65
SCCT Aero x4	1,500	33%	$58.91	N/A	$ 4.46	$ 41.33	$ 0.30	14.14%	$ 0.04	$ -	$100.58	$ -	-	$100.58
SCCT Frame "J" x1	1,500	33%	$35.51	N/A	$ 4.46	$ 40.48	$ 2.43	14.14%	$ 0.34	$ -	$78.76	$ -	-	$78.76
SCCT Frame "J" x1, 30H2 - onsite hydrogen production and liquified storage	1,500	33%	$119.91	N/A	$ 5.24	$ 48.10	$ 2.55	14.14%	$ 0.36	$ -	$170.93	$ -	-	$170.93
SCCT Frame "J" X1, 100H2 - onsite hydrogen production and liquified storage	1,500	33%	$191.81	N/A	$ 7.04	$ 66.76	$ 2.38	14.14%	$ 0.34	$ -	$261.29	$ (30.57)	ITC	$230.72
SCCT Frame "J" X1, 100H2 - pipeline Southern OR	1,500	33%	$69.03	N/A	$ 7.04	$ 66.76	$ 2.38	14.14%	$ 0.34	$ -	$138.51	$ (4.32)	ITC	$134.19
SCCT Frame "J" X1, 100H2, BF - onsite hydrogen production and liquified storage	1,500	33%	$174.13	N/A	$ 7.04	$ 66.76	$ 2.38	14.14%	$ 0.34	$ -	$243.61	$ (27.35)	ITC	$216.26
CCCT Dry "J", 1X1	1,500	78%	$20.76	N/A	$ 4.46	$ 27.80	$ 1.68	14.39%	$ 0.24	$ -	$50.49	$ -	-	$50.49
CCCT Dry "J", DF, 1x1	1,500	12%	$28.25	N/A	$ 4.46	$ 38.79	$ 1.15	14.39%	$ 0.16	$ -	$68.35	$ -	-	$68.35
SCCT Aero x4	3,000	33%	$55.59	N/A	$ 4.57	$ 42.48	$ 0.32	14.14%	$ 0.04	$ -	$98.43	$ -	-	$98.43
SCCT Frame "J" x1	3,000	33%	$30.98	N/A	$ 4.57	$ 41.50	$ 2.57	14.14%	$ 0.36	$ -	$75.41	$ -	-	$75.41
SCCT Frame "J" x1, 30H2 - onsite hydrogen production and liquified storage	3,000	33%	$120.14	N/A	$ 5.31	$ 48.84	$ 2.70	14.14%	$ 0.38	$ -	$172.06	$ -	-	$172.06
SCCT Frame "J" X1, 100H2 - onsite hydrogen production and liquified storage	3,000	33%	$195.92	N/A	$ 7.04	$ 66.80	$ 2.52	14.14%	$ 0.36	$ -	$265.59	$ (32.32)	ITC	$233.27
SCCT Frame "J" X1, 100H2, BF - onsite hydrogen production and liquified storage	3,000	33%	$177.22	N/A	$ 7.04	$ 66.80	$ 2.52	14.14%	$ 0.36	$ -	$246.90	$ (28.92)	ITC	$217.98
CCCT Dry "J", 1X1	3,000	78%	$20.01	N/A	$ 4.57	$ 28.48	$ 1.78	14.39%	$ 0.26	$ -	$50.52	$ -	-	$50.52
CCCT Dry "J", DF, 1x1	3,000	12%	$12.67	N/A	$ 4.57	$ 39.82	$ 1.15	14.39%	$ 0.16	$ -	$53.80	$ -	-	$53.80
SCCT Aero x4	5,050	33%	$59.29	N/A	$ 4.42	$ 41.24	$ 0.34	14.14%	$ 0.05	$ -	$100.92	$ -	-	$100.92
SCCT Frame "J" x1	5,050	33%	$32.85	N/A	$ 4.42	$ 40.15	$ 2.78	14.14%	$ 0.39	$ -	$76.17	$ -	-	$76.17
SCCT Frame "J" x1, 30H2 - onsite hydrogen production and liquified storage	5,050	33%	$129.00	N/A	$ 5.21	$ 47.90	$ 2.91	14.14%	$ 0.41	$ -	$180.22	$ -	-	$180.22
SCCT Frame "J" X1, 100H2 - onsite hydrogen production and liquified storage	5,050	33%	$210.67	N/A	$ 7.04	$ 66.85	$ 2.72	14.14%	$ 0.38	$ -	$280.61	$ (34.85)	ITC	$245.77
SCCT Frame "J" X1, 100H2 - pipeline Utah North	5,050	33%	$72.54	N/A	$ 7.04	$ 66.85	$ 2.72	14.14%	$ 0.38	$ -	$142.49	$ (4.91)	ITC	$137.57
SCCT Frame "J" X1, 100H2, BF - onsite hydrogen production and liquified storage	5,050	33%	$190.51	N/A	$ 7.04	$ 66.85	$ 2.72	14.14%	$ 0.38	$ -	$260.46	$ (31.18)	ITC	$229.28
SCCT Frame "J" X1, 100H2, BF - pipeline Dave Johnston	5,050	33%	$103.96	N/A	$ 7.04	$ 66.85	$ 2.72	14.14%	$ 0.38	$ -	$173.91	$ (4.91)	ITC	$169.00
SCCT Frame "J" X1, 100H2, BF - pipeline Hunter	5,050	33%	$45.13	N/A	$ 7.04	$ 66.85	$ 2.72	14.14%	$ 0.38	$ -	$115.08	$ (4.91)	ITC	$110.17
CCCT Dry "J", 1X1	5,050	78%	$21.42	N/A	$ 4.42	$ 27.57	$ 1.92	14.39%	$ 0.28	$ -	$51.18	$ -	-	$51.18
CCCT Dry "J", DF, 1x1	5,050	12%	$12.53	N/A	$ 4.42	$ 38.26	$ 1.15	14.39%	$ 0.16	$ -	$52.10	$ -	-	$52.10
SCCT Aero x4	6,500	33%	$68.89	N/A	$ 4.33	$ 39.89	$ 0.38	14.14%	$ 0.05	$ -	$109.22	$ -	-	$109.22
SCCT Frame "J" x1	6,500	33%	$37.89	N/A	$ 4.33	$ 39.32	$ 2.91	14.14%	$ 0.41	$ -	$80.53	$ -	-	$80.53
SCCT Frame "J" x1, 30H2 - onsite hydrogen production and liquified storage	6,500	33%	$138.66	N/A	$ 5.15	$ 47.30	$ 3.05	14.14%	$ 0.43	$ -	$189.44	$ -	-	$189.44
SCCT Frame "J" X1, 100H2 - onsite hydrogen production and liquified storage	6,500	33%	$224.34	N/A	$ 7.04	$ 66.82	$ 2.84	14.14%	$ 0.40	$ -	$294.41	$ (36.50)	ITC	$257.91
SCCT Frame "J" X1, 100H2, BF - onsite hydrogen production and liquified storage	6,500	33%	$203.23	N/A	$ 7.04	$ 66.82	$ 2.84	14.14%	$ 0.40	$ -	$273.30	$ (32.66)	ITC	$240.64
SCCT Frame "J" X1, 100H2, BF - pipeline Naughton	6,500	33%	$74.12	N/A	$ 7.04	$ 66.82	$ 2.84	14.14%	$ 0.40	$ -	$144.18	$ (5.15)	ITC	$139.04
SCCT Frame "J" X1, 100H2, BF - pipeline Jim Bridger	6,500	33%	$93.85	N/A	$ 7.04	$ 66.82	$ 2.84	14.14%	$ 0.40	$ -	$163.91	$ (5.15)	ITC	$158.77
CCCT Dry "J", 1X1	6,500	78%	$23.63	N/A	$ 4.33	$ 27.04	$ 2.01	14.39%	$ 0.29	$ -	$52.97	$ -	-	$52.97
CCCT Dry "J", DF, 1x1	6,500	12%	$21.96	N/A	$ 4.33	$ 37.21	$ 1.15	14.39%	$ 0.16	$ -	$60.48	$ -	-	$60.48

Table 5.4 – 2023 IRP Update Supply Side Resources (2022 $) (Continued)

Information Presented is Illustrative

Supply Side Resource Options Mid-Calendar Year 2022 Dollars ($)		Convert to $/MWh			Levelized Fuel							Credits		$/MWh
Resource Description	Elevation (AFSL)	Capacity Factor 3/	Total Fixed ($/MWh)	Storage Efficiency	$/mmBtu	$/MWh	O&M 1/	Capitalized Premium	O&M Capitalized 1/	Integration Cost 1/	Total Resource Cost	PTC Tax Credits / ITC (Solar Only) / 45Q Tax Credits (CCUS Only)	PTC Tax Credits / ITC (Solar Only) / 45Q Tax Credits (CCUS Only)	Total Resource Cost - with PTC / ITC / 45Q Credits
PC CCUS Oxy-Combustion retrofit @ 100 MW pre-retrofit basis	5,000	85%	$53.79	N/A	$ 4.42	$ 81.01	$ 18.68	0.00%	$ -	$ -	$153.49	$ (54.36)	45Q	$99.12
PC CCUS retrofit @ 330 MW pre-retrofit basis	6,500	85%	$38.81	N/A	$ 4.42	$ 69.13	$ 21.70	0.00%	$ -	$ -	$129.64	$ (43.13)	45Q	$86.51
PC CCUS retrofit @ 700 MW pre-retrofit basis	6,500	85%	$26.10	N/A	$ 4.42	$ 64.81	$ 20.79	0.00%	$ -	$ -	$111.69	$ (40.44)	45Q	$71.26
Li-Ion, 4-hour, 200 MW	N/A	17%	$135.55	85%	$ -	$ -	Included	0.00%	$ -	$ -	$135.55	$ (35.64)	ITC	$99.91
Incremental, double energy capacity (L-ion, 4hr, 200MW)	N/A	17%	$116.42	85%	$ -	$ -	Included	0.00%	$ -	$ -	$116.42	$ (29.16)	ITC	$87.26
Li-Ion, 4-hour, 500 MW	N/A	17%	$132.45	85%	$ -	$ -	Included	0.00%	$ -	$ -	$132.45	$ (34.81)	ITC	$97.63
Incremental, double energy capacity (L-ion, 4hr, 500MW)	N/A	17%	$114.21	85%	$ -	$ -	Included	0.00%	$ -	$ -	$114.21	$ (28.63)	ITC	$85.58
Li-Ion, 4-hour, 1000 MW	N/A	17%	$129.06	85%	$ -	$ -	Included	0.00%	$ -	$ -	$129.06	$ (33.91)	ITC	$95.15
Incremental, double energy capacity (L-ion, 4hr, 1000MW)	N/A	17%	$111.32	85%	$ -	$ -	Included	0.00%	$ -	$ -	$111.32	$ (27.90)	ITC	$83.42
Flow Battery, 4 hour, 200 MW	N/A	17%	$188.28	85%	$ -	$ -	$ 0.03	0.00%	$ -	$ -	$188.31	$ (59.22)	ITC	$129.08
Incremental, double energy capacity (Flow, 4hr, 200MW)	N/A	17%	$125.98	85%	$ -	$ -	$ -	0.00%	$ -	$ -	$125.98	$ (49.62)	ITC	$76.36
Flow Battery, 4 hour, 1000 MW	N/A	17%	$171.49	70%	$ -	$ -	$ 0.13	0.00%	$ -	$ -	$171.62	$ (54.97)	ITC	$116.65
Incremental, double energy capacity (Flow, 4hr, 1000MW)	N/A	17%	$112.48	85%	$ -	$ -	$ -	0.00%	$ -	$ -	$112.48	$ (45.57)	ITC	$66.91
Gravity Battery, 4 hour,	N/A	17%	$256.58	83%	$ -	$ -	Included	0.00%	$ -	$ -	$256.58	$ (111.55)	ITC	$145.03
Incremental, double energy capacity (Gravity, 4hr, 200MW)	N/A	17%	$109.65	83%	$ -	$ -	Included	0.00%	$ -	$ -	$109.65	$ (60.81)	ITC	$48.84
Gravity Battery, 4 hour,	N/A	17%	$239.97	83%	$ -	$ -	Included	0.00%	$ -	$ -	$239.97	$ (104.32)	ITC	$135.66
Incremental, double energy capacity (Gravity, 4hr, 500MW)	N/A	17%	$98.17	83%	$ -	$ -	Included	0.00%	$ -	$ -	$98.17	$ (54.44)	ITC	$43.72
Gravity Battery, 4 hour,	N/A	17%	$149.66	83%	$ -	$ -	Included	0.00%	$ -	$ -	$149.66	$ (65.06)	ITC	$84.60
Incremental, double energy capacity (Gravity, 4hr, 1000MW)	N/A	17%	$57.20	83%	$ -	$ -	Included	0.00%	$ -	$ -	$57.20	$ (31.72)	ITC	$25.48
Adiabatic CAES, RESC, 125 MW, 1000 MWh	6,500	33%	$61.36	60%	$ -	$ -	$ 1.05	6.27%	$ 0.07	$ -	$62.48	$ (18.35)	ITC	$44.12
Adiabatic CAES, RESC, 125 MW, 1250 MWh	6,500	38%	$55.00	60%	$ -	$ -	$ 1.05	6.27%	$ 0.07	$ -	$56.12	$ (16.46)	ITC	$39.65
Adiabatic CAES, RESC, 125 MW, 1500 MWh	6,500	38%	$60.08	60%	$ -	$ -	$ 1.05	6.27%	$ 0.07	$ -	$61.20	$ (18.18)	ITC	$43.01
Adiabatic CAES, RESC, 125 MW, 2000 MWh	6,500	38%	$61.87	60%	$ -	$ -	$ 1.05	6.27%	$ 0.07	$ -	$62.99	$ (18.78)	ITC	$44.21
Adiabatic CAES, RESC, 125 MW, 3000 MWh	6,500	38%	$65.97	60%	$ -	$ -	$ 1.05	6.27%	$ 0.07	$ -	$67.09	$ (20.16)	ITC	$46.93
Adiabatic CAES, RESC, 125 MW, 6000 MWh	6,500	38%	$87.21	60%	$ -	$ -	$ 1.05	6.27%	$ 0.07	$ -	$88.33	$ (27.31)	ITC	$61.02
Adiabatic CAES, RESC, 250 MW, 4000 MWh	6,500	38%	$55.90	60%	$ -	$ -	$ 1.05	6.27%	$ 0.07	$ -	$57.01	$ (17.24)	ITC	$39.78
Adiabatic CAES, RESC, 250 MW, 6000 MWh	6,500	38%	$62.06	60%	$ -	$ -	$ 1.05	6.27%	$ 0.07	$ -	$63.17	$ (19.31)	ITC	$43.86
Adiabatic CAES, RESC, 250 MW, 12000 MWh	6,500	38%	$81.48	60%	$ -	$ -	$ 1.05	6.27%	$ 0.07	$ -	$82.59	$ (25.84)	ITC	$56.75
Adiabatic CAES, RESC, 500 MW, 4000 MWh	6,500	33%	$52.02	60%	$ -	$ -	$ 1.05	6.27%	$ 0.07	$ -	$53.14	$ (16.00)	ITC	$37.14
Adiabatic CAES, RESC, 500 MW, 5000 MWh	6,500	38%	$46.53	60%	$ -	$ -	$ 1.05	6.27%	$ 0.07	$ -	$47.64	$ (14.31)	ITC	$33.33
Adiabatic CAES, RESC, 500 MW, 6000 MWh	6,500	38%	$49.50	60%	$ -	$ -	$ 1.05	6.27%	$ 0.07	$ -	$50.62	$ (15.32)	ITC	$35.30
Adiabatic CAES, RESC, 500 MW, 8000 MWh	6,500	38%	$52.58	60%	$ -	$ -	$ 1.05	6.27%	$ 0.07	$ -	$53.69	$ (16.35)	ITC	$37.34

Table 5.4 – 2023 IRP Update Supply Side Resources (2022 $) (Continued)

Information Presented is Illustrative

Supply Side Resource Options Mid-Calendar Year 2022 Dollars ($)					Levelized Fuel							Credits		$/MWh
Resource Description	Elevation (AFSL)	Capacity Factor 3/	al Fixed($/MWh	Storage Efficiency	$/mmBtu	$/MWh	O&M 1/	Capitalized Premium	O&M Capitalized 1/	Integration Cost 1/	Total Resource Cost	PTC Tax Credits / ITC (Solar Only) / 45Q Tax Credits (CCUS Only)	PTC Tax Credits / ITC (Solar Only) / 45Q Tax Credits (CCUS Only)	Total Resource Cost - with PTC / ITC / 45Q Credits
Adiabatic CAES, RESC, 500 MW, 12000 MWh	6,500	38%	$59.21	60%	$ -	$ -	$ 1.05	6.27%	$ 0.07	$ -	$60.32	$ (18.58)	ITC	$41.74
Adiabatic CAES, RESC, 500 MW, 24000 MWh	6,500	38%	$79.75	60%	$ -	$ -	$ 1.05	6.27%	$ 0.07	$ -	$80.87	$ (25.50)	ITC	$55.37
Pumped Hydro, Southern OR	N/A	42%	$78.09	78%	$ -	$ -	$ 0.51	0.00%	$ -	$ -	$78.60	$ (21.69)	ITC	$56.91
Pumped Hydro, Portland North Coast	N/A	42%	$78.09	78%	$ -	$ -	$ 0.51	0.00%	$ -	$ -	$78.60	$ (21.69)	ITC	$56.91
Pumped Hydro, Central WY	N/A	42%	$78.09	78%	$ -	$ -	$ 0.51	0.00%	$ -	$ -	$78.60	$ (21.69)	ITC	$56.91
Pumped Hydro, Eastern WY	N/A	42%	$78.09	78%	$ -	$ -	$ 0.51	0.00%	$ -	$ -	$78.60	$ (21.69)	ITC	$56.91
Pumped Hydro, Central UT	N/A	42%	$78.09	78%	$ -	$ -	$ 0.51	0.00%	$ -	$ -	$78.60	$ (21.69)	ITC	$56.91
100-hour Iron Air Battery, max CF: 17%	N/A	17%	$323.95	40%	$ -	$ -	Included	0.00%	$ -	$ -	$323.95	$ (102.03)	ITC	$221.92
Solar - Idaho Falls, ID, 20 MW, 26.1% CF	4,700	26%	$55.16	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.74	$55.90	$ (19.00)	PTC	$36.90
Solar - Lakeview, OR, 20 MW, 27.6% CF	4,800	28%	$55.21	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.74	$55.95	$ (19.00)	PTC	$36.95
Solar - Milford, UT, 20 MW, 30.2% CF	5,000	30%	$47.28	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.74	$48.01	$ (19.00)	PTC	$29.01
Solar - Milford, UT, 200 MW, 30.2% CF	5,000	30%	$39.87	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.74	$40.60	$ (19.00)	PTC	$21.60
Solar - Rock Springs, WY, 200 MW, 27.9% CF	6,400	28%	$44.57	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.74	$45.31	$ (19.00)	PTC	$26.31
Solar - Yakima, WA, 200 MW, 24.2% CF	1,000	24%	$52.20	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.74	$52.94	$ (19.00)	PTC	$33.94
Solar + Storage - Idaho Falls, ID, 200 MW, 26.1% CF + BESS: 100% pwr, 4 hours	4,700	26%	$120.49	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.74	$121.22	$ (54.64)	ITC	$66.58
Solar + Storage - Lakeview, OR, 200 MW, 27.6% CF + BESS: 100% pwr, 4 hours	4,800	28%	$113.56	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.74	$114.29	$ (54.64)	ITC	$59.65
Solar + Storage - Milford, UT, 200 MW, 30.2% CF + BESS: 100% pwr, 4 hours	5,000	30%	$104.18	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.74	$104.92	$ (54.64)	ITC	$50.28
Solar + Storage - Rock Springs, WY, 200 MW, 27.9% CF + BESS: 100% pwr, 4 hours	6,400	28%	$113.43	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.74	$114.17	$ (54.64)	ITC	$59.53
Solar + Storage - Yakima, WA, 200 MW, 24.2% CF + BESS: 100% pwr, 4 hours	1,000	24%	$133.35	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.74	$134.08	$ (54.64)	ITC	$79.44
Wind - Pocatello, ID, 20 MW, CF: 37.1%	4,500	37%	$59.30	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$60.27	$ (19.00)	PTC	$41.27
Wind - Pocatello, ID, 200 MW, CF: 37.1%	4,500	37%	$47.74	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$48.71	$ (19.00)	PTC	$29.71
Wind - Arlington, OR, 20 MW, CF: 37.1%	1,500	37%	$59.05	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$60.03	$ (19.00)	PTC	$41.03
Wind - Arlington, OR, 200 MW, CF: 37.1%	1,500	37%	$47.13	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$48.10	$ (19.00)	PTC	$29.10
Wind - Monticello, UT, 20 MW, CF: 29.5%	4,500	30%	$75.22	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$76.19	$ (19.00)	PTC	$57.19
Wind - Monticello, UT, 200 MW, CF: 29.5%	4,500	30%	$60.79	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$61.76	$ (19.00)	PTC	$42.76
Wind - Medicine Bow, WY, 20 MW, CF: 43.6%	6,500	44%	$49.90	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$50.88	$ (19.00)	PTC	$31.88
Wind - Medicine Bow, WY, 200 MW, CF: 43.6%	6,500	44%	$40.11	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$41.08	$ (19.00)	PTC	$22.08
Wind - Goldendale, WA, 20 MW, CF: 37.1%	1,500	37%	$61.60	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$62.58	$ (19.00)	PTC	$43.58
Wind - Goldendale, WA, 200 MW, CF: 37.1%	1,500	37%	$49.04	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$50.01	$ (19.00)	PTC	$31.01
Wind - Offshore, Northern, CA, CF: 47.0%	0	47%	$103.63	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$104.60	$ (13.36)	ITC	$91.24
Wind -Offshore, Northern, CA, 1GW, CF: 47.0%	0	47%	$103.59	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$104.56	$ (13.36)	ITC	$91.20
Wind + Storage - Pocatello, ID, 200 MW, CF: 37.1% + BESS: 100% pwr, 4 hours	4,500	37%	$96.51	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$97.48	$ (54.64)	ITC	$42.84
Wind + Storage - Arlington, OR, 200 MW, CF: 37.1% + BESS: 100% pwr, 4 hours	1,500	37%	$93.96	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$94.93	$ (54.64)	ITC	$40.29
Wind + Storage - Monticello, UT, 200 MW, CF: 29.5% + BESS: 100% pwr, 4 hours	4,500	30%	$122.44	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$123.41	$ (54.64)	ITC	$68.77
Wind + Storage - Medicine Bow, WY, 200 MW, CF: 43.6% + BESS: 100% pwr, 4 hours	6,500	44%	$81.46	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$82.43	$ (54.64)	ITC	$27.79
Wind + Storage - Goldendale, WA, 200 MW, CF: 37.1% + BESS: 100% pwr, 4 hours	1,500	37%	$98.53	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$99.50	$ (54.64)	ITC	$44.86
Wind + Storage - Offshore, Northern, CA, CF: 47.0% + BESS: 100% pwr, 4 hours	0	47%	$145.61	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$146.59	$ (54.64)	ITC	$91.94
Idaho Falls, ID Solar + Wind + BESS: 100% pwr, 4 hours	4,700	62%	$106.00	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.85	$106.86	$ (54.64)	ITC	$52.22
Lakeview, OR Solar + Wind + BESS: 100% pwr, 4 hours	4,800	62%	$103.73	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.85	$104.59	$ (54.64)	ITC	$49.95
Milford, UT Solar + Wind + BESS: 100% pwr, 4 hours	5,000	58%	$113.73	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.85	$114.58	$ (54.64)	ITC	$59.94
Rock Springs, WY Solar + Wind + BESS: 100% pwr, 4 hours	6,400	70%	$88.77	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.85	$89.62	$ (54.64)	ITC	$34.98
Yakima, WA Solar + Wind + BESS: 100% pwr, 4 hours	1,000	59%	$107.35	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.85	$108.20	$ (54.64)	ITC	$53.56
Geothermal - Dual Flash Expansion of Blundell Plant	4,500	90%	$44.87	N/A	$ -	$ -	$ -	0.00%	$ -	$ -	$44.87	$ (19.00)	PTC	$25.87
Geothermal - Greenfield Binary Plant	4,500	90%	$58.08	N/A	$ -	$ -	$ -	0.00%	$ -	$ -	$58.08	$ (19.00)	PTC	$39.08
Nuclear - Advanced LWR, 600 MW Site	N/A	86%	$95.68	N/A	$ -	$ -	$ -	0.00%	$ -	$ -	$95.68	$ (19.00)	PTC	$76.68
Nuclear - Advanced LWR, 1200 MW Site	N/A	86%	$84.15	N/A	$ -	$ -	$ -	0.00%	$ -	$ -	$84.15	$ (19.00)	PTC	$65.15
Advanced Nuclear Reactor (AR), dual unit, with Thermal Storage (1000 Mwe interconnection with 1705 MWh Storage, 638 MW initial base generation)	N/A	86%	$142.34	N/A	$ -	$ -	$ -	0.00%	$ -	$ -	$142.34	$ (19.00)	PTC	$123.34
Advanced Nuclear Reactor (AR) with improved fuel (1000 Mwe interconnection with 1705 MWh Storage, 690 MW base generation)	N/A	86%	$115.27	N/A	$ -	$ -	$ -	0.00%	$ -	$ -	$115.27	$ (19.00)	PTC	$96.27

1/ Input into IRP SO and PAR Model

2/ Wind and solar shapes are input into IRP Plexos Model

NC = Not Calculated

Tax credits are before Energy Community bonus as it is site specific

Information Presented is Illustrative

CCUS costs are incremental and include envirnomental upgrade costs but are missing underlying coal unit costs

Modeling Enhancements and Resource Updates

Suspension of the 2022 All-Source RFP

The decision to suspend the 2022 All-Source RFP was made on September 29, 2023, four months after the filing of the 2023 IRP. The decision to suspend was taken for multiple reasons, all with the intent to ensure that our procurement decisions are based on the most up-to-date information and in the best interests of our ratepayers, while also considering the evolving market conditions and other pertinent factors: (1) The stay of EPA's disapproval of Utah's state ozone plan; (2) Ongoing rulemaking by the EPA regarding greenhouse gas emissions, with impacts on our system to be determined; (3) Wildfire risk and associated liability across our six-state service area and throughout the West; and (4) Evolving extreme weather risks that necessitate further decision-making regarding PacifiCorp's operational and resource requirements.

In parallel with the modeling updates, the PacifiCorp has engaged in a bilateral effort to procure commercially viable battery technology by June 1, 2026, to ensure that such near-term opportunities remain available. The 2023 IRP Update provides new direction on resource needs spanning the timeframe of the 2022 All-Source RFP and indicates appropriate next steps.6

Transmission Option Updates

The 2023 IRP Update has changed the way the majority of transmission projects are modeled. Transmission projects do not have to be selected as one unit or zero units, but can be selected in any size from zero to 100% of a line. In practice, this means that if the model deems it most economic to build .25 units of a local area upgrade can be built in 2033, another .3 units can be built in 2034 and the balance can be left unbuilt. For local area upgrades, this correlates more closely to real world cluster project transmission and funding where (as an example) 30% of the cluster chooses to move forward and the balance withdraws. When considering incremental lines, given the far future timelines for those items, this modeling provides appropriate flexibility considering permitting nuances and the complex nature of transmission approvals. Selection of a portion of an incremental transmission line in the distant future signals that this transmission option has value to the system and warrants further study to determine the best sizing and timing of the line. The exception to this change is that known, incremental, near-term projects such as the Boardman to Hemingway and Energy Gateway South lines must be selected as whole projects. Further engagement with stakeholders regarding transmission modeling methodology will occur in the 2025 IRP public input meetings series.

[6] Please refer to Chapter 6 – Portfolio Development, and Chapter 7 – Action Plan.

Other Contracts

PacifiCorp continually updates and negotiates with contracted facilities. The most current contracted resources, as of January 1, 2024, are being used for the 2023 IRP Update. Given timing, this is the last update to contracted resources that will be made for the update. Between the 2023 IRP and the 2023 IRP Draft Update, PacifiCorp has signed an additional 13 megawatts of small Oregon Community Solar Projects that will be reflected in the 2023 IRP Update.

As an original purchaser of the output of the Priest Rapids and Wanapum hydro projects, PacifiCorp has an annual option to purchase approximately 100 megawatts of the output from these plants at market-based rates. For this 2023 IRP Update, it has been assumed that PacifiCorp elects to purchase this hydro output in each year of the study horizon.

CHAPTER 6 – PORTFOLIO DEVELOPMENT

Introduction

PacifiCorp used PLEXOS' three optimization models to develop an updated preferred portfolio based on inputs and assumptions that have changed since the 2023 Integrated Resource Plan (IRP). This updated resource portfolio is consistent with PacifiCorp's most recent load-and-resource balance.[1] This chapter presents the 2023 IRP Update preferred portfolio, a comparison of changes relative to the 2023 IRP preferred portfolio, and an updated assessment of certain portfolio variants.

Updates

Key Updates

As discussed in Chapter 5, key changes in this 2023 IRP Update are driven by the U.S. Environmental Protection Agency's (EPA) approval of Wyoming's state Ozone Transport Rule (OTR) plan, the stay of EPA's disapproval of Utah's state OTR plan, extensions to the assumed operational life of new natural gas generating resources, energy storage acquisition strategy, forecast load demand, higher coal prices, and natural gas and wholesale power market price updates.

The first of these items, the OTR, is particularly impactful. Since the time the 2023 IRP was filed, the Tenth Circuit Court of Appeals granted PacifiCorp's and other petitioners' motion to stay the EPA's final disapproval of Utah's state implementation plans regarding cross-state ozone transport obligations under the 2015 ozone National Ambient Air Quality Standards (referred to herein as the Ozone Transport Rule or OTR). The stay will remain in place while the case is litigated, or until further order of the court. The court held that the agency may not enforce the federal plan while the stay remains in place. PacifiCorp is thus not subject to the federal ozone transport requirements in Utah, which would have become effective on August 4, 2023. Requirements for the 2024 ozone season and beyond will depend on the outcome of litigation. In granting the stay, the court indicated that PacifiCorp and the other petitioners are likely to succeed on the merits. As discussed later in this chapter, PacifiCorp has produced a variant analysis to understand the potential impacts of litigation outcomes that could reinstate OTR compliance requirements for Utah resources.

Additionally, the EPA finalized approval of Wyoming's interstate ozone transport plan on December 19, 2023. The final approval of Wyoming's plan removes federal cross-state ozone transport requirements from electric generating units in the state, including PacifiCorp's generating units. The rule is discussed in Chapter 3.

[1] See Chapter 4 – Load and Resource Balance

Other Updates

In addition to the key updates noted above, the 2023 IRP Update includes conventional or traditional planning updates where data has changed following PacifiCorp's filed 2023 IRP. Included are updates to load forecast, market prices, changes in existing resources, and PacifiCorp's contracts with other entities.

Certain updates to proxy resource data are responsive stakeholder feedback. These updates result in better alignment with potential for some renewable categories, such as pumped storage and geothermal resources, as well as updates to thermal and nuclear assumptions.

Gas resources have been updated to reflect the potential flexibility of fuel types as discussed in Chapter 5. This ability to transition to alternative fuels allows gas resources to operate and provide benefits over a longer useful life. This allows upfront costs to be amortized over a longer useful life, which reduces annual costs and leads to greater probability that these resources will be selected.

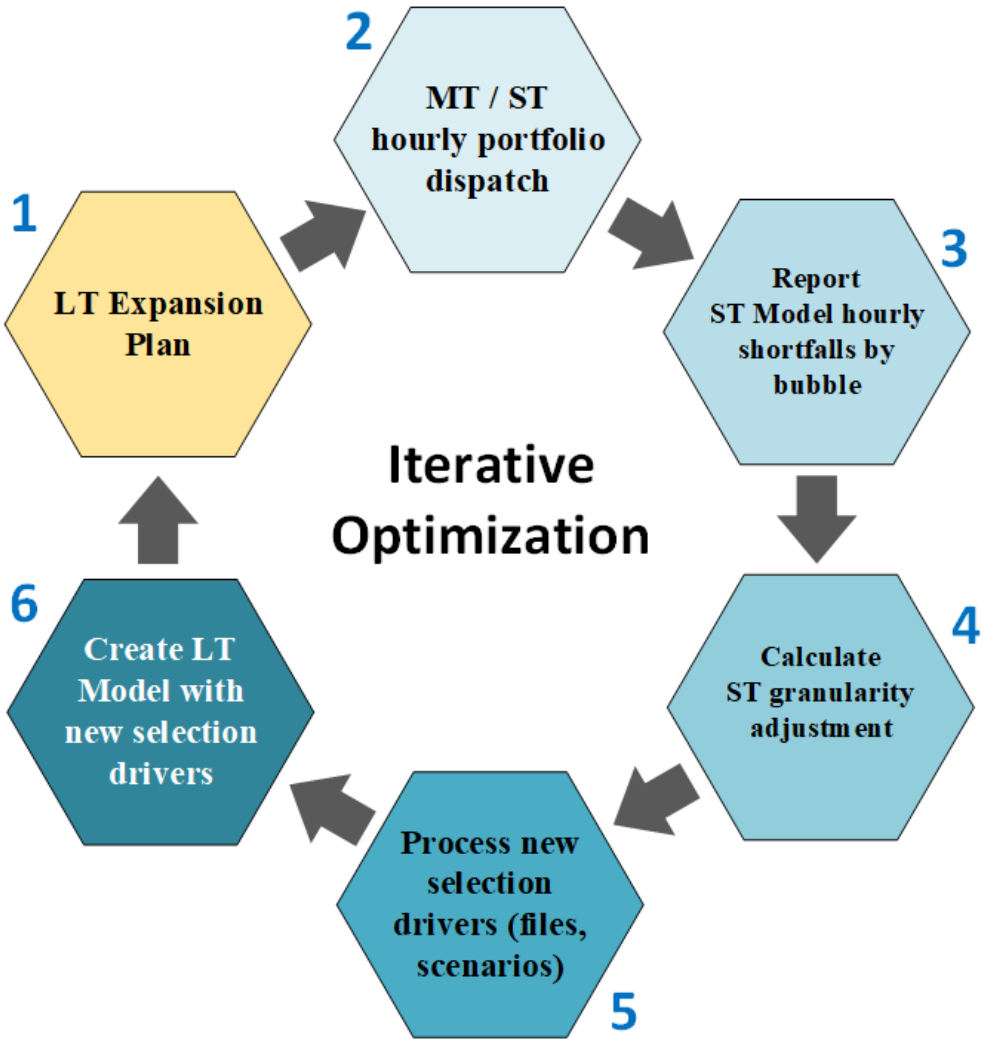
The change to transmission modeling discussed in Chapter 5 has an impact on portfolio selections as PLEXOS is able to "right-size" transmission to fit needs more precisely. This also means that transmission selections can be built in multiple years, reflecting the reality that resources studied in the PacifiCorp Transmission cluster study process may not all reach operational status in the same year, and transmission investments to enable these projects could potentially be staggered.

Within the limits of their useful lives, coal plants are eligible to be retired any time after January 1, 2024, and gas plants are eligible for retirement at any point after January 1, 2026. This serves to standardize assumptions and allows the model to indicate if earlier retirements would be selected if feasible. To the extent that earlier retirements are indicated within the limits of PLEXOS, further study could be made.

Portfolio Development Process Overview

In the 2023 IRP Update process, the company revised the process for developing candidate portfolios. In response to stakeholder feedback requesting greater transparency in the process of making portfolio-level reliability adjustments and model simulation granularity adjustments, the company implemented a new, iterative process to generate candidate portfolios. Each iteration in the portfolio process represents one "phase", and each phase consists of six steps. Figure 6.1 illustrates the six cyclical steps in this new process, followed by an overview and detailed description of these steps. Completion of all six steps of this process constitutes a single phase of a study.

Figure 6.1 – The Six Steps of One Portfolio Development Phase



Overview of Steps

Step 1

For each case, the long-term (LT) capacity expansion model is run according to the parameters and constraints of the particular study. This results in an expansion plan of selected resources, retirement decisions and transmission option selection. Collectively these selections are called a "portfolio".

Step 2

The LT model expansion plan is fed into the medium-term (MT) and short-term (ST) models. These two models are run in sync where the MT model optimizes the timing and allocation of constraints, and the ST model performs an hourly dispatch of the portfolio using the MT model's determinations. For example, if there is limited fuel available to a thermal unit during a year, the MT will allocate that fuel across the year to give the ST model direction for how much fuel is available in each part of the year.

Step 3

The ST model reports shortfalls that must be covered for each location (or "bubble") in the IRP transmission topology.

Step 4

The granularity adjustment is calculated as the difference in resource value between the ST model results and the LT model results. This calculation gives the mathematical magnitude of the ST model's superior granularity.

Step 5

The reliability shortfalls and granularity adjustments are formatted into data files that can be used in the next phase of the LT model to improve its outcomes.

Step 6

The next phase LT model is built in PLEXOS, where shortfalls are represented as an additional load requirement and the granularity adjustment is represented as a cost adder to every resource option.

Granularity Adjustment Detail

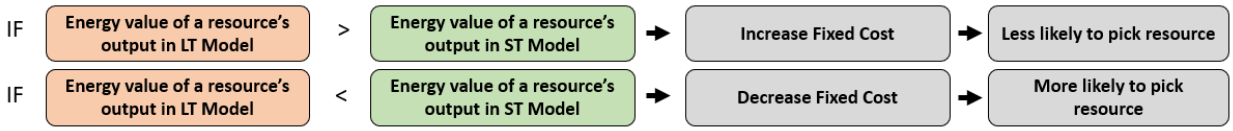
The capacity expansion/LT and ST models in PLEXOS each run and solve using a different view of the study horizon. The LT model uses 7 blocks per month over the 20-year horizon. This means the LT model groups similar hours into a block, and then concurrently solves the entire 20-year horizon. In contrast, the ST model concurrently solves (or dispatches) each week of each year, or roughly 52 steps of 168 hours each, for a specified portfolio of resources as selected in the LT model. In the 7-block LT view, a resource is seen as having a certain amount of value to the system in the 84 blocks it evaluates during each year (7 blocks per month times 12 months). When the ST model dispatches those same resources at an hourly granularity, the ST model also reports the value it calculates for each resource on an annual basis. The mathematical difference between the ST value and the LT value is the granularity adjustment.

This adjustment, determined independently in step 4 of each phase of portfolio development, is used in the subsequent phase of the process so as to bring the ST model's finer granularity analysis into the LT model, improving the consistency of capacity expansion.

By contrast, in the 2023 IRP, the ST model resource value results were used to inform additional resource selections that were then applied directly in a final run of the ST model. This new iteratively phased approach means that resource selections occur in the LT model using its capacity expansion logic, but with the benefit of the ST model's resource value determinations. Also responsive to stakeholder feedback, a new granularity adjustment is now calculated for every portfolio developed, rather than using one granularity adjustment calculated for each price-policy scenario. This change, while performance and resource intensive, is responsive to stakeholder concerns regarding the limitations of the prior methodology.

Figure 6.2 illustrates the calculation of the granularity adjustment, which is completely derived from ST and LT model outputs. A distinct granularity adjustment is calculated for every individual resource in each year of every phase of every study.

Figure 6.2 – Granularity Adjustment Determination



This iterative process was carried out for all price-policy scenarios and variant studies. Since each unique granularity adjustment was then fed back into the LT model for the next run, in practice, this means that no two LT model runs have the same granularity adjustment, and each adjustment is wholly dependent upon the performance of resources within that specific portfolio.

Reliability Adjustment Detail

Stakeholders in the 2023 IRP also identified concerns related to the methodology for making reliability adjustments. For the 2023 IRP Update, in step 3 of each phase, hourly reliability shortfalls are identified by the ST model to be fed back into the LT model to enhance resource selections. As previously noted, the LT model evaluates average conditions during blocks of hours. While this allows the LT model to solve a long horizon in a reasonable time, the average conditions in a block of hours can result in shortfalls in some hours within a block when viewed with enhanced granularity. The ST model is able to identify these hours in its evaluation, and these deficiencies are reported by the ST model as hourly shortfalls.

While granularity adjustments are included as an increase or decrease in fixed costs, reliability adjustments are now included as an increase in the load forecast. As with the granularity adjustments these additions are specific to each study's portfolio. However, unlike the granularity adjustment, the shortfall additions to the load file are cumulatively added to the LT need. ST studies are always run with the base load forecast to verify whether LT additions were sufficient to eliminate shortfalls in all hours.

As an example, suppose the phase one portfolio (the very first iteration of the six steps for a particular study) reports a shortfall of 250 megawatts in Utah North on June 8, 2032, at 8 PM. This 250 megawatt shortfall is added to the base load file on June 8, 2032, in Utah North, and phase 2 is run with the adjusted load file. If the portfolio selected in phase two reports an additional shortfall of 50 megawatt in Utah North on June 8, 2032, at 8 PM, the 50 megawatt shortfall is added to the adjusted load file, such that the load for that day and time is now 300 megawatts higher than the original phase one load forecast. Once no shortfalls are reported by the ST model (using the base load forecast), the adjusted load file used to select a reliable portfolio continues to be applied so that each later phase includes requirements sufficient to induce the LT model to select a portfolio that is reliable. These adjustments are unique to each price policy scenario/variant.

These changes in the application of reliability and granularity adjustments has led to an iterative process where there is a loop from the LT model to the MT and ST models and back to the LT model. This process can be continual, and results evolve over multiple phases. At some point, the process leads to a portfolio that is reliable. Additionally, ongoing granularity adjustments will lead to diminishing returns on cost reductions. The process is considered complete once portfolios are reliable and the present value revenue requirement (PVRR) of reliable portfolios reports changes within a small range.

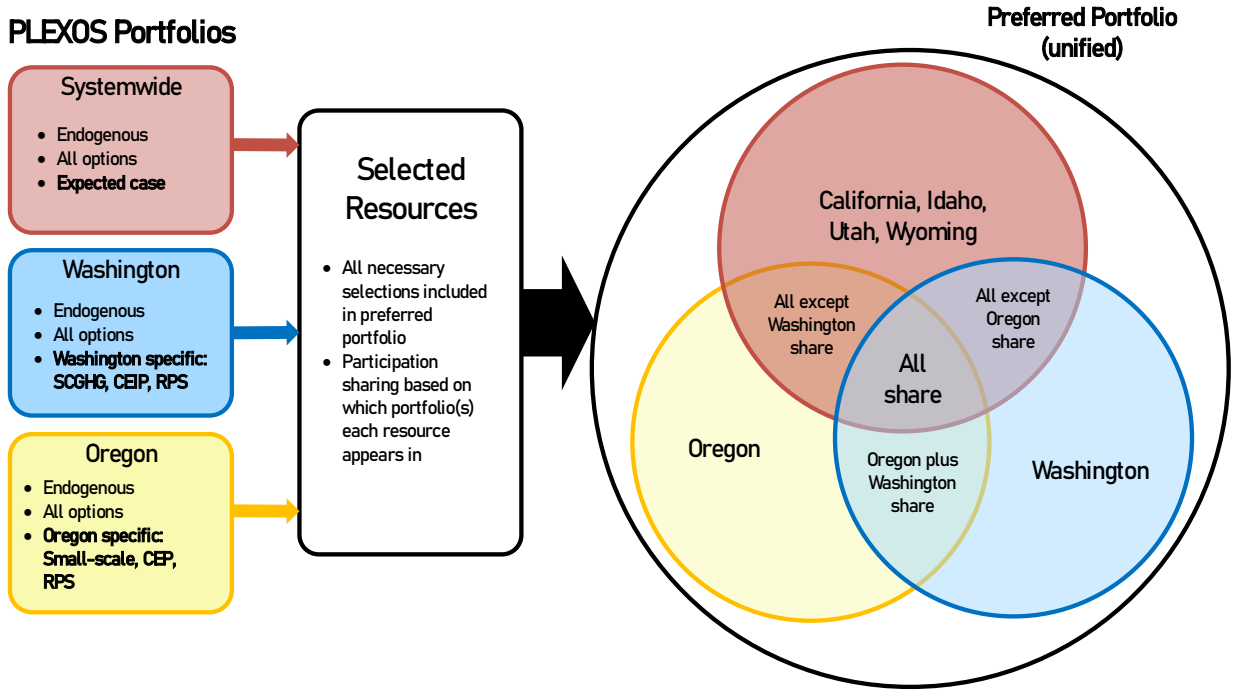
Preferred Portfolio Development

As discussed above, the iterative study process was completed for all studies in the 2023 IRP Update. The fully unconstrained Medium Gas, Medium CO_2 (MM) study was iterated through eight distinct phases of granularity or reliability adjustments before reaching a point where the results stabilized, and no further significant progress was evident. The portfolios generated in this eight-phase study process were all eligible to be selected as the systemwide best portfolio.

Given state policy requirements, however, the systemwide portfolio was not expected to meet all state-specific compliance obligations. To generate an optimal, all-state portfolio, the systemwide portfolio must be integrated with selections optimized under each state's requirements, requiring additional studies. These additional studies were created by layering state compliance constraints into the LT model, and these model runs went through the same iterative process as described above. The preferred portfolio leveraged the resource selections of the least-cost MM system-wide portfolio, the least-cost MM Oregon Policy portfolio and the least-cost Social Cost of Greenhouse Gas (SC-GHG) Washington Policy portfolio.

Figure 6.3 illustrates the strategy for the integration of optimal resource selections for all states. Using the figure as a guide, if a given resource is selected as optimal for one state but is not selected in the systemwide portfolio nor for any other individual state, then that resource is assumed to belong to the selecting state to meet its specific requirements. If a resource is selected as optimal for a specific state and systemwide portfolio, it is assumed shared.

Figure 6.3 – Integrated Portfolio Strategy



Systemwide Portfolio

This portfolio was developed through the iterative process without any initial restrictions on resource selection, state needs, transmission availability, or any other inputs. Given the universal benefit of some number of renewables in the iterative approach (phases with higher renewable selections led to an overall lower PVRR), it became clear that the LT model would select additional renewables if the model had the benefit of improved granularity. PacifiCorp began testing strategies that required the model to pick minimum amounts of renewable resources that interconnection study results indicate could be available through 2028. The model was still allowed to select additional renewable resources. The amounts tested ranged from 15% to 100% of the resources modeled as available through 2028 from the serial, transition, cluster one and cluster two interconnection studies. The version requiring 25% of these resources had the lowest PVRR of the tests, therefore the 25% requirement was carried through further systemwide cases. The MM systemwide case requiring the selection of 25% of the cluster study options serves as the starting point for the integrated preferred portfolio. This approach allowed multiple additional iterations to be avoided without risk of overbuilding renewables.

Oregon and Washington Policy Portfolios

While many resources identified in the unconstrained systemwide portfolio are cost-effective for Washington and Oregon policy requirements, separate portfolios were developed which included the policy requirements specific to each state. These portfolios were developed in tandem with the system-level portfolio using the same iterative process. State policy studies include the entire system but also compliance metrics based on that state's regulations. The LT model thus produces a portfolio in these studies in which the entire system is optimized in a way that complies with the state policies. Per Figure 6.1, above, a state's assumed share of resources is determined according to the overlap observed in the integration process, described in detail for Oregon and Washington respectively, below.

The least-cost versions of the Oregon and Washington policy portfolios are used in two ways. First, an allocated portion of the selections identified in the compliance portfolios are integrated with the systemwide portfolio. While the systemwide portfolio is the starting point given the substantial overlap among the portfolios, the modifications associated with the state policy portfolios may increase, accelerate, or replace selections in the systemwide portfolio to produce an integrated preferred portfolio that addresses all requirements. Second, the integrated preferred portfolio resource selections are assumed allocated to California, Idaho, Utah, and Wyoming only to the extent they were identified in the systemwide portfolio. Similarly, resource selections are assumed allocated to Oregon only to the extent identified in the Oregon policy portfolio, and resource selections are allocated to Washington only to the extent identified in the Washington policy portfolio.

This approach differs from the approach used in the March 2023 filing of the Oregon Clean Energy Plan (CEP), the March 2023 Washington Clean Energy Implementation Plan (CEIP) re-filing, and the November 2023 Washington Biennial Update portfolio developments. Specifically, the previous approach used in the aforementioned filings locked-in the unconstrained systemwide portfolio and then added only the minimal incremental resource selections needed to meet state policies. This earlier approach in PacifiCorp's first CEP and CEIP reports was viewed by PacifiCorp as entirely valid in an environment where all portfolios were very closely aligned and

optimal resource additions were minimal. Responsive to stakeholder and commission feedback, the new approach for the 2023 IRP Update integrates resource selections from fully optimized state policy model runs rather than "layering resources on top" of the systemwide solution.

This approach is expected to be discussed with regulators and stakeholders and subsequently refined for the 2025 IRP. In the current version of this approach, resource adequacy is achieved for the system but is not examined for each individual jurisdiction. For the 2025 IRP, the use of individual jurisdictional forecasts and individual resource allocations is being contemplated to ensure that each state is independently resource adequate. This prevents resource adequacy impacts of individual state policies from shifting to other states.

Oregon Integration

The Oregon policy study represents the model's view of the least-cost, least-risk resource portfolio for Oregon, irrespective of the unconstrained systemwide portfolio. The process of integration maintains each other states' optimal resource outcomes without diminishing Oregon's selections. However, Oregon is not beholden to adopt the model's recommendations, and the PacifiCorp intends to continue its dialogue with all states to seek the best solutions for its customers. A comprehensive compliance strategy for Oregon will be influenced by staff and Commission guidance, stakeholder engagement, MSP negotiations, resource acquisition procedures, and a number of possible compliance options beyond capacity expansion. These additional considerations are outside the scope of the 2023 IRP Update, but will be considered in separate engagements and reports according to Oregon requirements.

Relative to the systemwide portfolio, the Oregon policy study adds peaking resources with renewable fuel in 2030, additional utility scale wind, as well as small-scale renewable resources mandated by Oregon law. The renewable-fueled peaking unit replaces a hydrogen convertible gas-fueled peaking unit from the systemwide portfolio. This resource is assumed to be fully allocated to Oregon. The Oregon share of the incremental utility-scale wind resource additions is comparable to the small-scale wind requirement, and so Oregon's share of utility scale wind will be acquired as small-scale resources in the integrated portfolio. Utility-scale solar selections decrease in the Oregon run compared to the unconstrained systemwide portfolio, even when required small-scale solar additions are considered. Therefore, utility-scale solar in the preferred portfolio is reduced slightly relative to the systemwide portfolio to represent a reduction in Oregon's share of that resource. The Oregon policy study also results in an acceleration of battery resources relative to the systemwide portfolio. Oregon energy efficiency and demand response measures, already fully allocated to Oregon, are taken directly from the results of the Oregon compliance study for inclusion in the integrated all-state preferred portfolio.

Washington Integration

Similar to Oregon's policy portfolio integration, Washington's policy study was compared to the unconstrained systemwide portfolio, and Washington's situs selections were integrated based on the differences between resource selections in the two portfolios. As anticipated, when the system is planned and operated on the basis of the SC-GHG CO_2 assumption, as in the Washington policy study, total system resource selections are considerably in excess of those needed by Washington to achieve Clean Energy Transformation Act (CETA) clean energy targets. This is because while resources are selected for the entire system, Washington only needs a relatively small share of

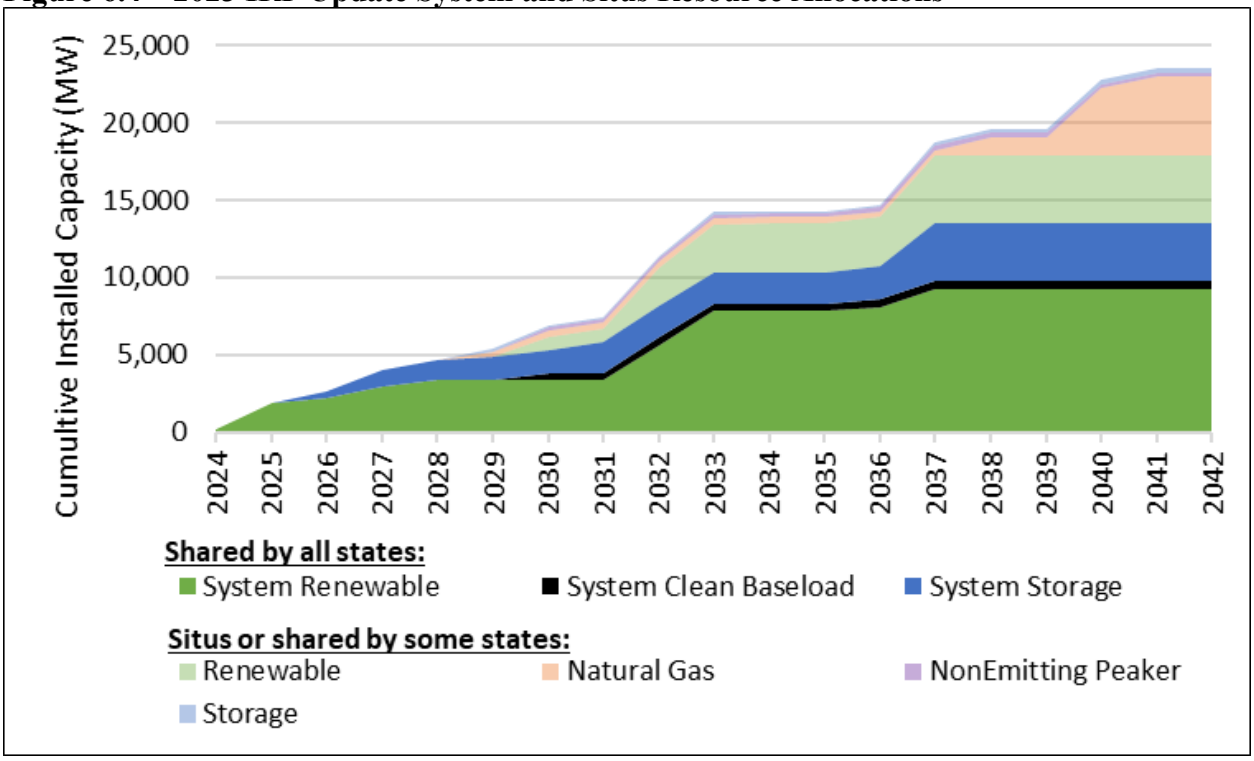
those resources for its own jurisdictional goals. A second study was therefore performed which assumed a larger share of new resources attributed to Washington, based on Washington's roughly 22% share of PacifiCorp's western states (also known as Control Area Generation West or CAGW). This results in fewer total resources and ensures that selected resources are the best of what is available. After accounting for the policy benefits of Washington's system share of the resource selections previously identified in the systemwide study, the CAGW study results indicated that wind resources were the best means of compliance, and over 400 megawatts of additional wind resources in 2030 were incorporated in the preferred portfolio that would be fully allocated to Washington. Washington is also allocated additional wind and solar resources in 2032-2037, and a small amount of battery resources which were accelerated into 2029. Additionally, demand response and energy efficiency in the preferred portfolio match the selections from the Washington policy run.

A comprehensive compliance strategy for Washington will be influenced by staff and Commission guidance, stakeholder engagement, MSP negotiations, resource acquisition procedures, and a number of possible compliance options beyond capacity expansion. These additional considerations are outside the scope of the 2023 IRP Update, but will be considered in separate engagements and reports according to Washington requirements.

Preferred Portfolio Integration Outcomes

The integrated preferred portfolio resulting from the changes described above is mostly shared among all states, though differences grow in the second half of the study horizon, as shown in Figure 6.4.

Figure 6.4 – 2023 IRP Update System and Situs Resource Allocations



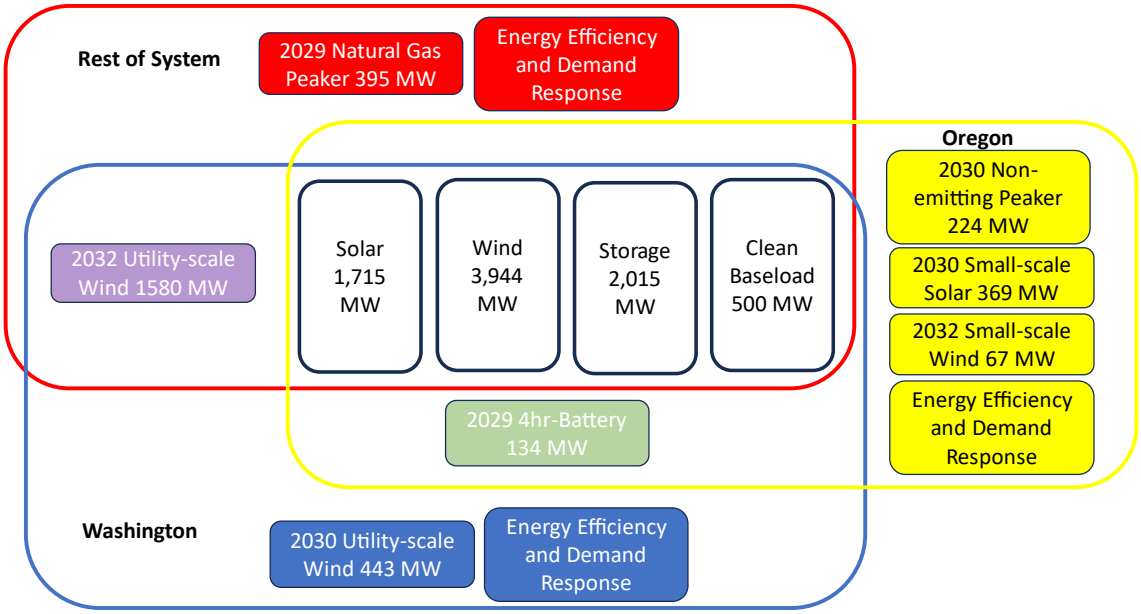
Much of the preferred portfolio closely matches the least cost systemwide MM portfolio. The preferred portfolio moves 134 megawatts of battery early into 2029 from 2031, 2036 and 2037, and adds a total of 101 megawatts of battery storage over the system view. Total peaking is 43 megawatts higher in the preferred portfolio than in the system view, although 224 megawatts of gas peaking units are assumed to be non-emitting to meet state requirements, whereas the system-wide portfolio assumed all gas peaking is fueled by natural gas. The integration of Oregon and Washington energy efficiency and demand response adds 109 total megawatts. Washington's 443 megawatts of situs wind comes online in 2030, and Oregon's small-scale wind and solar are integrated into 2030-2033, reducing Oregon's share of utility-scale solar in 2033, 2034, and 2037. No other changes were indicated by state-level requirements, and the situs wind and small-scale renewables are all assumed to be situs to Oregon and Washington. Table 6.1 below shows changes to the systemwide portfolio for state compliance, color coded by which state required the change.

Table 6.1 – Preferred Portfolio Resource Integrations (Installed Capacity, MW)

Situs/Partial Share Resources	Oregon	Washington	OR and WA	WA and Sys	OR and Sys	No OR/WA								
Category	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Natural Gas	395	-	-	-	-	-	-	-	-	836	-	3122	749	-
NonEmitting Peaker	-	224	-	-	-	-	-	-	59	-	-	-	-	-
Utility Scale Wind	-	443	-	1580	15	-	-	-	-	-	-	-	-	-
Small Scale Wind	-	-	-	67	172	-	-	-	-	-	-	-	-	-
Utility Scale Solar	-	-	-	-	449	93	-	-	1009	-	-	-	-	-
Small Scale Solar	-	369	5	-	-	-	-	-	109	-	-	-	-	-
Clean Baseload	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4hr Battery	134	-	11	8	-	3	-	-	78	-	-	17	9	-
Storage (Long Duration)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	529	1036	16	1655	636	96	0	0	1255	836	0	3139	758	0

Figure 6.5 below shows allocations through 2032 of all resources in the preferred portfolio using similar Venn diagram imagery to Figure 6.3, above.

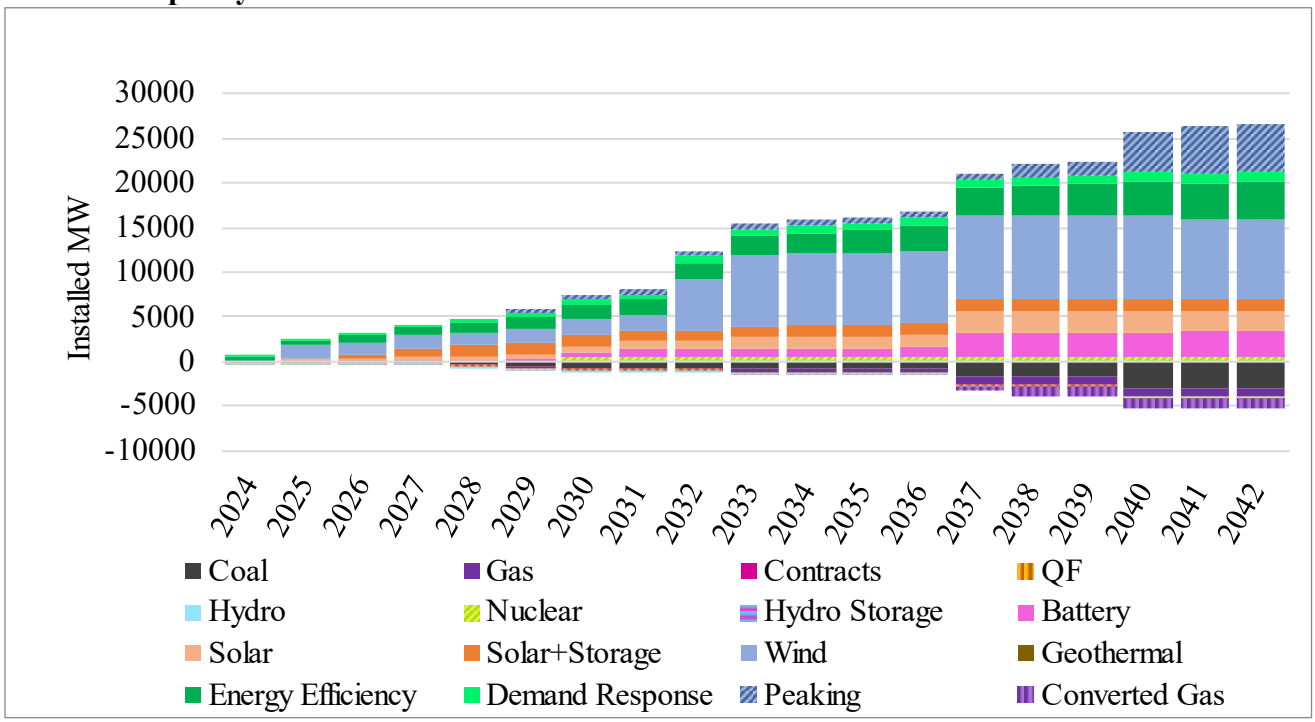
Figure 6.5 – Allocation of the 2023 IRP Update Preferred Portfolio Through 2032



Preferred Portfolio Results

Figure 6.6 reports that PacifiCorp's 2023 IRP Update integrated preferred portfolio continues to include substantial new renewables, facilitated by incremental transmission investments, demand-side management (DSM) resources, significant storage resources, Natrium™ advanced nuclear, and peaking resources.

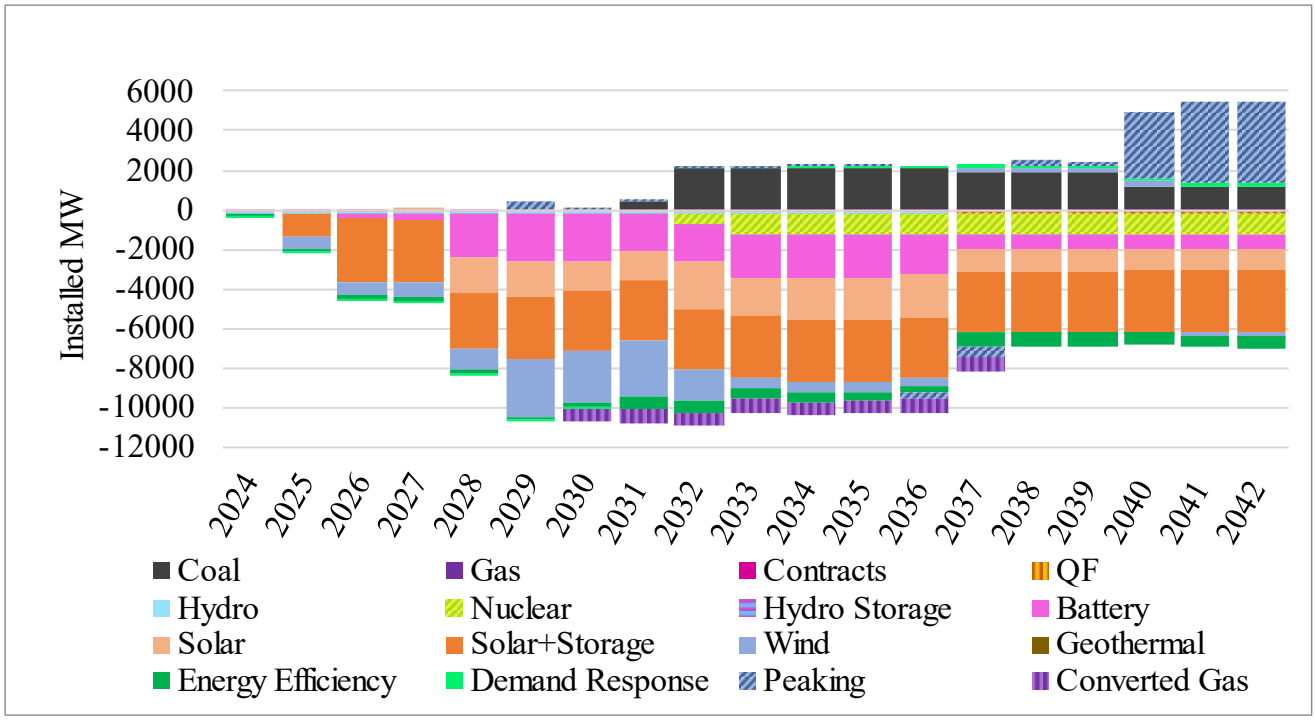
Figure 6.6 – 2023 IRP Update All-State Preferred Portfolio Cumulative Changes in Installed Capacity



*Note: "Coal" includes both minority and majority owned coal resources, including Jim Bridger Units 3 and 4 with CCUS. "Coal" does not include coal resources converted to gas. Coal resources converted to gas are categorized under "Converted Gas" and only show at retirement, as the conversion does not increase the installed capacity of the resource. "Gas" includes only existing gas resources. New gas peaking and new hydrogen peaking resources are grouped under "Peaking". "Nuclear" includes only the Natrium™ advanced nuclear project.

Figure 6.7 summarizes the annual nameplate capacity in the 2023 IRP Update relative to the 2023 IRP preferred portfolio for the 19-year period 2024 through 2042. Consistent with the updates to the OTR and changes in gas peaking unit assumptions, significant differences can be seen between the 2023 IRP and the 2023 IRP update.

Figure 6.7 – Cumulative Increase/(Decrease) in 2023 IRP Update less 2023 IRP Preferred Portfolio



As a result of EPA's approval of Wyoming's OTR plan and the stay of EPA's disapproval of Utah's OTR plan, certain coal units' end-of-life assumptions vary from the 2023 IRP. There is a reduction in early solar and wind resources given the existing thermal fleet's ability to operate with fewer restrictions. The adjustment to include gas peaking resources as convertible to a non-emitting fuel in the future led to an increased selection of peaking units. This selection offsets some renewables due to the peaking units' ability to generate as needed.

Present Value Revenue Requirement

The 2023 IRP Update Preferred Portfolio represents the least cost study over the 20-year study horizon, with a PVRR of $32.807b under the MM price policy scenario. While the overall PVRR of the preferred portfolio is lowest during the study horizon, the final years of the portfolio represent a cost when compared to the unconstrained, systemwide study. From 2040 to 2042, the preferred portfolio is, on average, $72m more costly each year than the unconstrained system portfolio. This indicates that the resources necessary for individual state compliance added relative to the unconstrained system portfolio would not be cost-effective over their economic lives.

In addition to evaluating portfolios under the MM price policy scenario, select variant studies were also modeled under each of the other price curves. Under the Medium Gas, No CO_2 price curve, and the Low Gas, No CO_2 price curve, the systemwide portfolio is least-cost. In other words, the preferred portfolio proves to be the most robust when different future price environments are considered. Tables showing the preferred portfolio and select variants run under the different price policy assumptions appear at the end of the chapter.

Transmission Upgrades

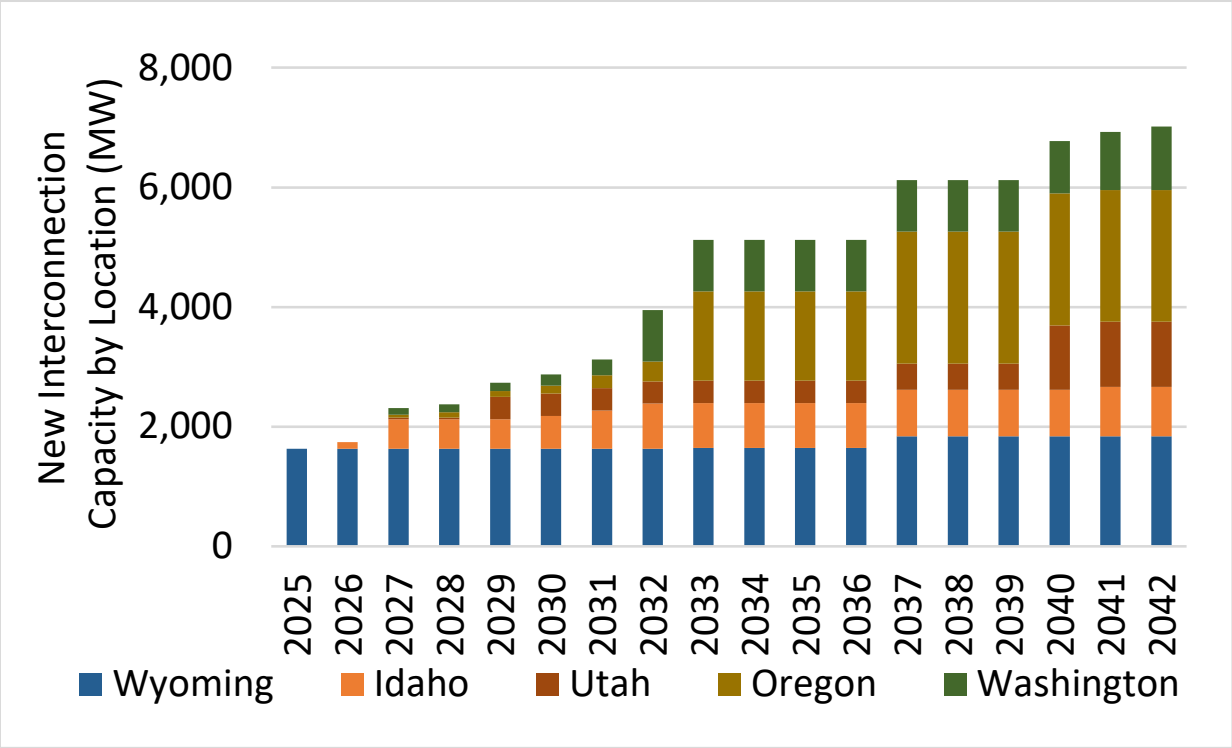
To facilitate the delivery of new resources to PacifiCorp customers across the West, the 2023 IRP Update preferred portfolio includes additional transmission investment. As supported by needs established in previous IRPs, PacifiCorp is finalizing construction of the Energy Gateway South and Energy Gateway West Sub-Segment D1 transmission projects and partnering with Idaho Power to build the B2H transmission project, which is expected to come online in the 2026-2027 timeframe. B2H is a 290-mile high-voltage 500 kilovolt transmission line that connects the Longhorn substation near the town of Boardman in Oregon to the Hemingway substation in Idaho. By exchanging certain transmission assets with Idaho Power Company, PacifiCorp will receive additional transmission rights between Hemingway and the Populus substation in Idaho, which is closely tied to existing and future PacifiCorp transmission connecting to Utah and Wyoming. At the Oregon end of the B2H line, additional transmission upgrades are planned to connect B2H to growing loads.

In the 2023 IRP Update, many transmission upgrades and the accompanying resources reflect the results of PacifiCorp's generator interconnection "cluster study" process for evaluating proposed resource additions. By evaluating all newly proposed resource additions in an area at the same time, the cluster study process identifies collective solutions that can allow projects that are ready to move forward to do so in a timely fashion. As a result, transmission upgrades and resource additions in the 2023 IRP Update preferred portfolio consider cluster study requests submitted in the past several years. Additional transmission expansion projects can include development of new segments and exploration of new routes that have connections to other areas. Figure 6.8 summarizes the new interconnection capacity selected to facilitate new generation resources identified as part of the 2023 IRP Update preferred portfolio.

In addition to providing increased interconnection capacity, transmission upgrades are also expected to allow for increased transfer capability between different areas of PacifiCorp's system. The 2023 IRP Update preferred portfolio includes portions of the following transmission upgrades between the following areas within the IRP topology. Note that modeling for the 2023 IRP Update allowed for partial selection of lines, though that does not indicate that these lines would be uneconomic if built in their entirety. Given the timing identified primarily in the second half of the IRP study horizon, these opportunities will continue to be explored in the future.

- Walla Walla to Yakima.
- Gateway Sub-Segment D3: provides direct transfers between Jim Bridger and Borah (Populus), but with supporting projects, also facilitates transfers between Wyoming East and Jim Bridger and between Borah and Utah North.
- Incremental Gateway Segments: Segments D2.2, D1.2, and Gateway South 2 would be the second iteration of existing or soon to be in service segments from the original Gateway plan and would provide additional transfer capability between Wyoming East and Bridger and between Wyoming East and Clover.
- Oregon 500 kilovolt upgrades: several 500 kilovolt upgrades and supporting projects would connect Portland-North Coast, Willamette Valley, Southern Oregon, and Central Oregon.
- East-West transfers: together, B2H 2 and Gateway Segment E would further increase transfer capability between PacifiCorp's east and west balancing authority areas.

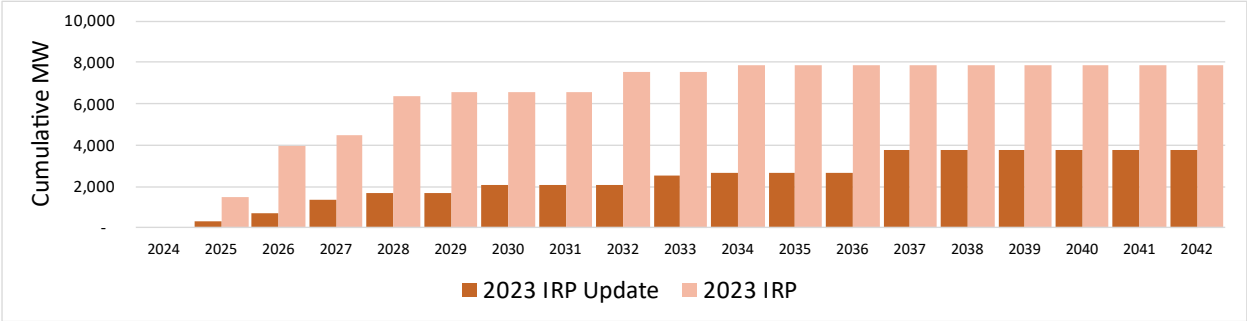
Figure 6.8 – New Interconnection Capacity by Location, 2023 IRP Update Preferred Portfolio



New Solar Resources

The 2023 IRP Update preferred portfolio includes 2,084 megawatts of solar by the end of 2030, and 3,749 megawatts of new solar is online by 2037, as shown in Figure 6.9. While not shown in Figure 6.9, the company has also previously contracted for one gigawatt of solar resources with commercial operation dates between 2024 and 2026 for customer-directed voluntary renewable procurement programs.

Figure 6.9 – 2023 IRP Update Preferred Portfolio New Solar Capacity*

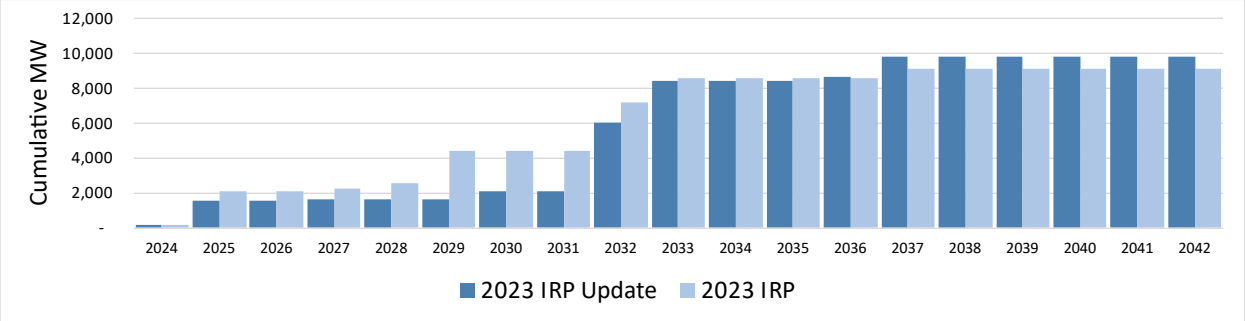


* 2023 IRP Update solar capacity shown in the figure includes committed solar resources shown in 2025 and 2026. Resources are shown in the first full year of operation (the year after the year-online dates). This total includes 374 megawatts of small scale solar to meet Oregon requirements.

New Wind Resources

As shown in Figure 6.10, by 2032, PacifiCorp's 2023 IRP Update preferred portfolio includes 6,034 megawatts of new wind resources, and more than 9,800 megawatts of new wind resources by 2037.

Figure 6.10 – 2023 IRP Update Preferred Portfolio New Wind Capacity*

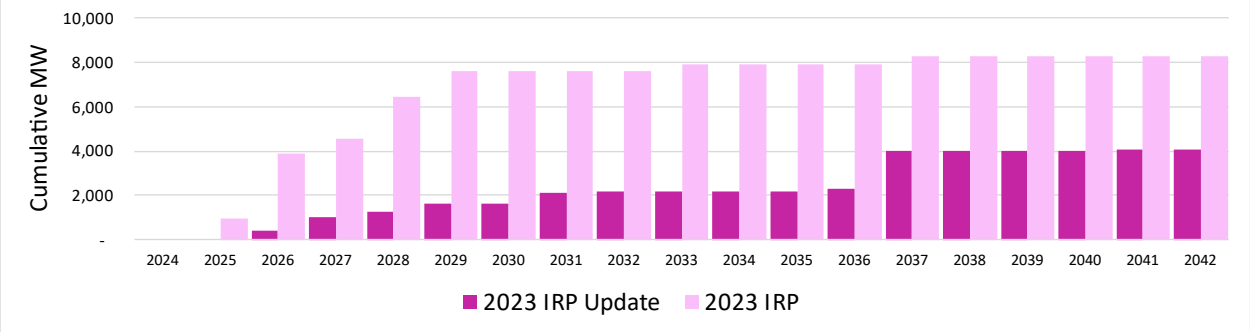


*Note: Wind additions shown are incremental to Energy Vision 2020 and other projects that have come online over the past few years. Resources are shown in the first full year of operation (the year after year-end online dates). This figure includes 254 megawatts of small-scale wind to meet Oregon requirements, and an additional 443 megawatts of utility scale wind to meet Washington requirements.

New Storage Resources

As shown in Figure 6.11, the 2023 IRP Update preferred portfolio includes 1,626 megawatts of new storage capacity by the end of year 2029 and more than 4,000 megawatts by 2037.

Figure 6.11 – 2023 IRP Update Preferred Portfolio New Storage Capacity*

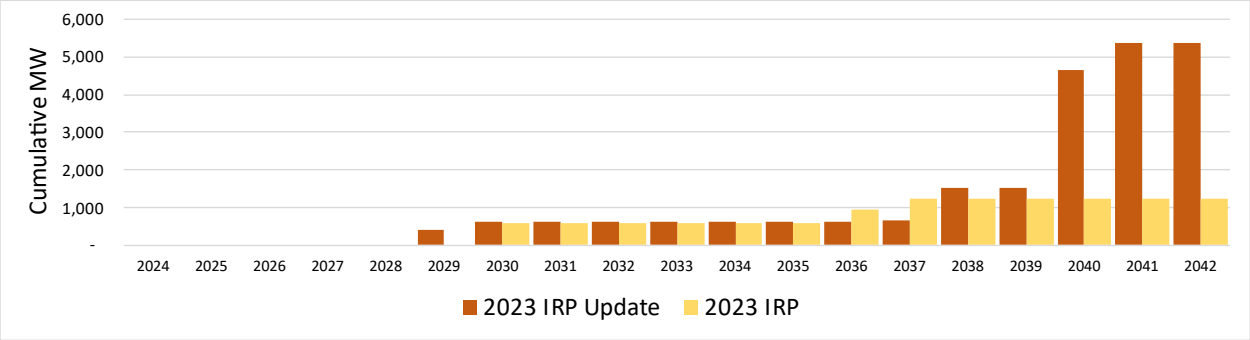


*Note: Resources are shown in the first full year of operation (the year after the year-end online dates). This figure includes a total of 101 megawatts of storage resources required by Oregon and Washington for compliance

Peaking Capacity

The 2023 IRP Update continues to indicate the need for flexible peaking capacity to achieve reliability and minimize risk. A key change since the filing of the 2023 IRP is the addition of peaking capacity in the form of natural gas resources capable of operating with 100% hydrogen fuel. The inclusion of this technology also guards against the future risk of increasingly constrained emissions and future policy requirements.

Figure 6.12 – 2023 IRP Update Preferred Portfolio Peaking Resources Capacity*

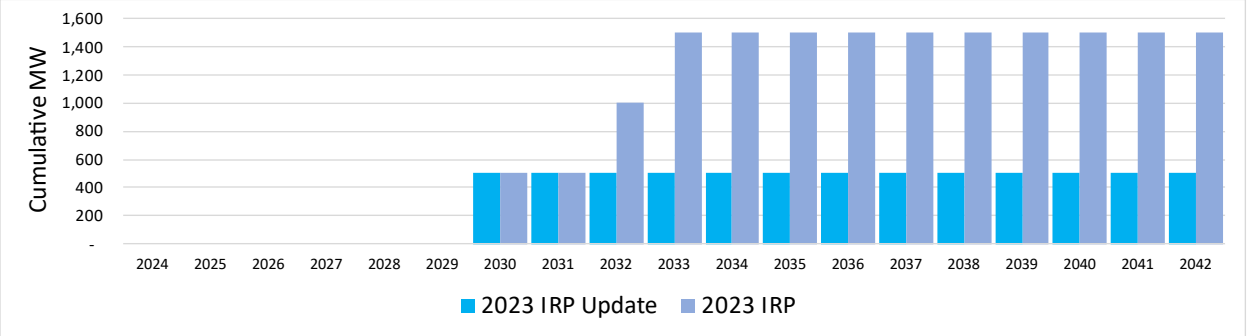


*Note: Resources are shown in the first full year of operation (the year after the year-end online dates). This figure includes 224 megawatts of peaking units for Oregon compliance that can only run on clean fuel.

Nuclear Capacity

The 2023 IRP Update continues to show the value associated with the Natrium™ Demonstration Project which provides a significant non-emitting resource. A key change since the filing of the 2023 IRP is the stay of the EPA's disapproval of Utah's OTR plan and subsequent ability of the existing thermal fleet to operate with fewer restrictions as a dispatchable resource. Although additional advanced nuclear resources beyond the Natrium™ Demonstration Project are not selected in this update, PacifiCorp is continually updating advanced nuclear resource cost estimates as they become available.

Figure 6.13 – 2023 IRP Update Preferred Portfolio New Nuclear Capacity



Demand-Side Management

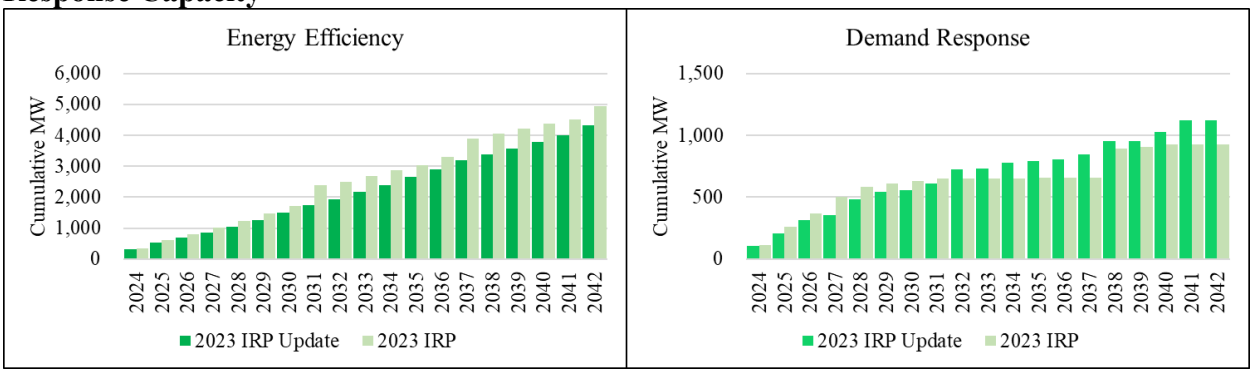
PacifiCorp evaluates new DSM opportunities, which includes both energy efficiency and demand response programs, as a resource that competes with traditional new generation and wholesale power market purchases when developing resource portfolios for the IRP. The optimal determination of DSM resources results in selecting all cost-effective DSM as a core function of IRP modeling. Consequently, the load forecast used as an input to the IRP does not reflect any incremental investment in new energy efficiency programs; rather, the load forecast is reduced by the selected additions of energy efficiency resources in the IRP Update.

DSM resources continue to play a key role in PacifiCorp's resource mix. The chart to the left in Figure 6.14 compares total energy efficiency capacity savings in the 2023 IRP Update preferred

portfolio relative to the 2023 IRP preferred portfolio and includes 4,326 megawatts by the end of the planning period.

In addition to continued investment in energy efficiency programs, the preferred portfolio shows a need for incremental demand response programs. The chart to the right in Figure 6.14 compares cumulative demand response program capacity in the 2023 IRP Update preferred portfolio relative to the 2023 IRP preferred portfolio and does not include capacity from existing programs. The 2023 IRP Update has a cumulative capacity of incremental demand response programs reaching 1,123 megawatts by 2042 which represents a 21% increase relative to the 2023 IRP.

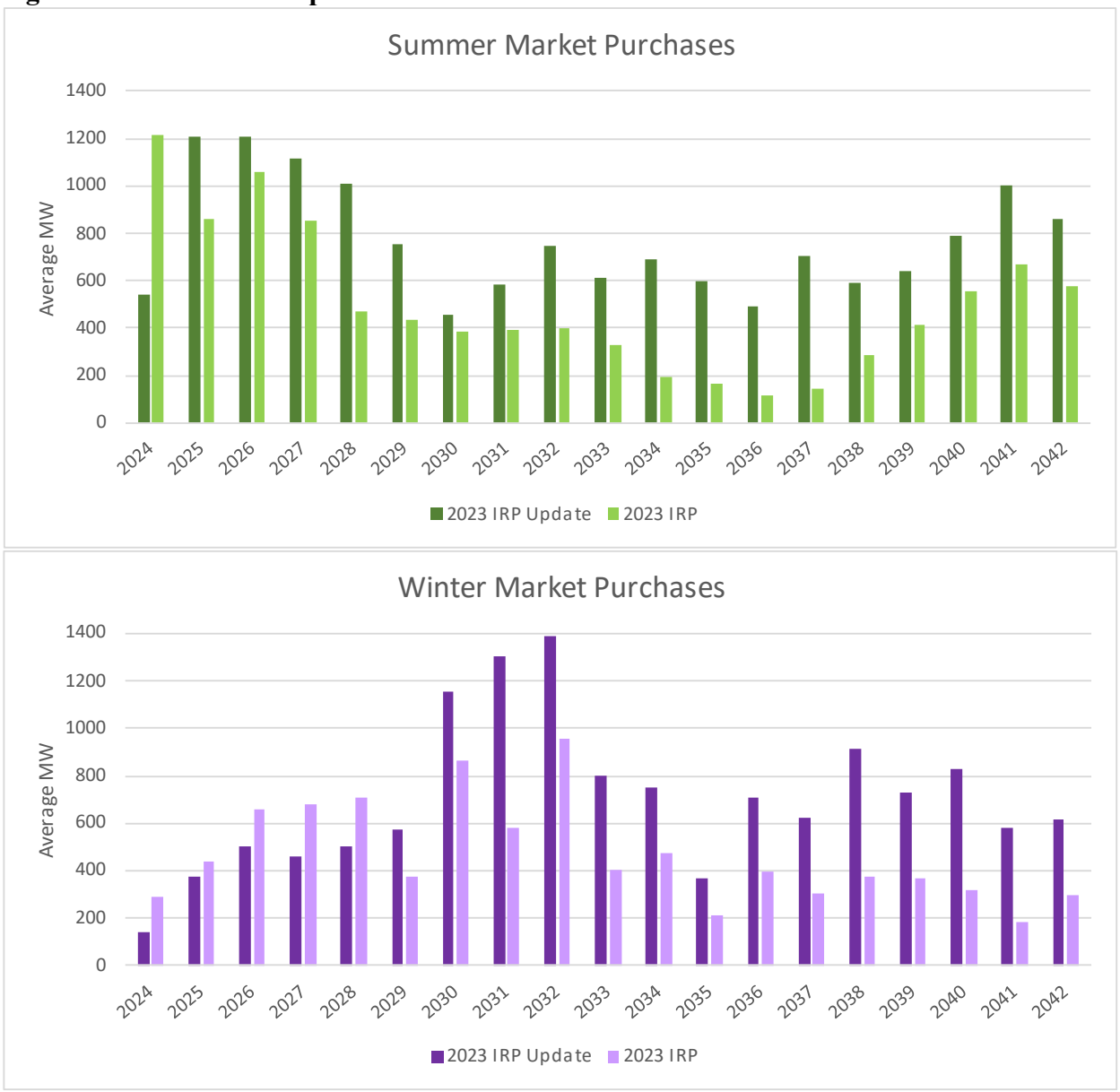
Figure 6.14 – 2023 IRP Update Preferred Portfolio Energy Efficiency and Demand Response Capacity



Market Activity

Subsequent to the filing of the 2023 IRP, the EPA's approval of Wyoming's state OTR plan and the stay of EPA's disapproval of Utah's state OTR plan removed the restrictions that limited energy production in the summer from natural gas and coal-fueled resources in Wyoming and Utah. In the absence of the OTR, market purchases can cost-effectively replace some of the incremental renewable resources that were indicated in the 2023 IRP preferred portfolio, leading to higher relative market activity, as shown in Figure 6.15 below. In addition, a 500 megawatt capacity Wyoming market has been added in the 2023 IRP update, representing the ongoing ability to access diverse (and potentially new) regional markets as discussed in Chapter 3.

Figure 6.15 – 2023 IRP Update Preferred Portfolio Market Purchases



*Note: "Summer Market Purchases" includes purchases from June through September while "Winter Market Purchases" includes purchases from December and January. While most data for tables and figures in this document comes from LT capacity expansion model results, this figure uses ST model results. For market data, it is appropriate

to use ST model results because the ST model is run with an hourly granularity which more accurately represents the energy needed to meet load obligations compared to the less granular LT capacity expansion model.

Coal and Gas Retirements/Gas Conversions

Coal resources have been an important resource in PacifiCorp's resource portfolio for many years. The operating capabilities of these facilities have been able to adapt to changes in the planning environment. For example, PacifiCorp has been able to lower operating minimums and optimize coal dispatch through the Energy Imbalance Market (EIM). This in turn has enabled the company to both reduce fuel consumption and associated costs and emissions by increasingly buying low-cost, zero-emissions renewable energy from market participants across the West, which is accessed by our expansive transmission grid. PacifiCorp's coal resources will continue to play a pivotal role in following fluctuations in renewable energy as the remaining coal units approach retirement dates. EPA's approval of Wyoming's ozone plan and the stay of EPA's disapproval of Utah's ozone plan results in fewer restrictions on coal-fired operation than were assumed in the 2023 IRP. With these updates, Utah coal resources are no longer planned to retire early, as shown in Table 6.2. Hunter and Huntington coal unit retirements, specifically, have returned to the schedule that had been previously indicated by PacifiCorp's 2021 IRP.

Table 6.2 – Coal Unit Retirements in the 2023 IRP and 2023 IRP Update

Coal			
Unit	2023 IRP Retirement Year (12/31/__)	2023 IRP Update Retirement Year (12/31/__)	Delta to 2023 IRP (Years)
	As Selected	As Selected	
Colstrip 3	2025	2025	-
Colstrip 4	2029	2029	-
Craig 1	2025	2025	-
Craig 2	2028	2028	-
DaveJohnston 1	2028	2028	-
DaveJohnston 2	2028	2028	-
DaveJohnston 3	2027	2027	-
DaveJohnston 4	2039	2039	-
Hayden 1	2028	2028	-
Hayden 2	2027	2027	-
Hunter 1	2031	2042	11
Hunter 2	2032	2042	10
Hunter 3	2032	2042	10
Huntington 1	2032	2036	4
Huntington 2	2032	2036	4
JimBridger 1	2037	2037	-
JimBridger 2	2037	2037	-
JimBridger 3	2037	2039	2
JimBridger 4	2037	2039	2
Naughton 1	2036	2036	-
Naughton 2	2036	2036	-
Wyodak	2039	2039	-

Coal unit exits, retirements, gas conversions, and retrofits scheduled under the preferred portfolio include:

- 2023 = Jim Bridger Units 1-2, converted to natural gas in 2024 (same as in the 2023 IRP)
- 2025 = Craig Unit 1 retirement (same as in the 2023 IRP)
- 2026 = Naughton Units 1-2, converted to natural gas in 2026, operates through 2036 (same as in the 2023 IRP)
- 2027 = Dave Johnston Unit 3 retirement (same as in the 2023 IRP)
- 2027 = Hayden Unit 2 retirement (same as in the 2023 IRP)

- 2028 = Jim Bridger Units 3-4, retrofitted with carbon capture technology in 2028, operates through 2039 (converted to gas conversion in 2030 and retired in 2037 in the 2023 IRP; unit life is extended by 2 years to capture 12 full years of investment tax credits)
- 2028 = Dave Johnston Units 1-2 retirement (same as in the 2023 IRP)
- 2028 = Craig Unit 2 retirement (same as in the 2023 IRP)
- 2028 = Hayden Unit 1 retirement (same as in the 2023 IRP)
- 2029 = Colstrip Unit 4 exit, Colstrip Unit 3 share is consolidated into Colstrip Unit 4 in 2025 (same as in the 2023 IRP)
- 2036 = Huntington Units 1-2 retirement, no emissions controls (SNCR installation in 2026, operating through 2032 in the 2023 IRP)
- 2039 = Dave Johnston Unit 4 retirement (same as in 2023 IRP)
- 2039 = Wyodak retirement, no emissions controls (SNCR installation in 2026, operating through 2039 in the 2023 IRP)
- 2042 = Hunter Units 1-3 retirement, no emissions controls (SNCR installation in 2026, operating through 2031 and 2032 in the 2023 IRP)

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Table 6.3 – Comparison of 2023 IRP Update with 2023 IRP Preferred Portfolio (Megawatts)

2023 IRP Update

Summary Portfolio Capacity by Resource Type and Year, Installed MW

Resource	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	Total
Expansion Options																				
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Peaking	-	-	-	-	-	395	224	-	-	-	-	-	-	59	836	-	3,122	749	-	5,385
DSM - Energy Efficiency	151	211	160	175	192	219	224	250	196	224	230	257	252	292	187	178	218	231	314	4,161
DSM - Demand Response	38	98	110	35	133	61	11	56	112	9	42	14	12	43	108	-	71	95	3	1,051
Renewable - Wind	194	1,361	-	79	-	-	443	5	3,952	2,354	-	-	228	1,202	-	-	-	-	-	9,818
Renewable - Utility Solar	-	300	398	654	363	-	369	5	-	449	93	-	-	1,118	-	-	-	-	14	3,763
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	400	565	297	337	-	521	21	-	3	-	152	1,694	-	-	17	9	-	4,016
Renewable - Battery (Long Duration)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	27	-	-	-	-	-	-	-	-	-	-	-	-	-	8	-	-	35
Nuclear	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	500
Existing Unit Changes																				
Coal Plant Retirements - Minority Owned	-	-	(82)	-	(33)	(123)	(148)	-	-	-	-	-	-	-	-	-	-	-	-	(386)
Coal Plant Retirements	-	-	-	-	(220)	(205)	-	-	-	-	-	-	-	(909)	-	-	(598)	-	-	(1,932)
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(699)	-	-	(699)
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	-	-	-	-	-	-	-	-	-	-	-	-	(357)	(713)	-	-	-	-	(1,070)
Gas Plant Retirements	-	-	-	-	-	-	-	-	-	(358)	-	-	-	(484)	-	-	-	-	-	(842)
Retire - Hydro	(47)	-	-	-	-	-	-	-	-	-	-	-	-	(7)	-	-	-	-	-	(54)
Retire - Non-Thermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(32)	-	-	-	-	(32)
Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(519)	-	(519)
Retire - Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	(18)	-	-	-	-	-	(18)
Expire - Wind PPA	(41)	-	(64)	-	-	-	(99)	(200)	-	-	-	-	-	-	-	-	-	-	-	(405)
Expire - Solar PPA	-	-	-	-	(2)	-	-	-	(7)	-	-	-	-	(73)	-	-	-	(4)	-	(86)
Expire - QF	(50)	-	(0)	(1)	-	(3)	-	-	-	-	-	-	(0)	(1)	-	-	-	(1)	(1)	(57)
Expire - Other	(161)	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	(161)
Total	**84**	**1,970**	**948**	**1,507**	**730**	**682**	**1,524**	**637**	**4,274**	**2,678**	**368**	**271**	**644**	**2,558**	**386**	**178**	**2,139**	**559**	**330**	

2023 IRP Update less 2023 IRP Preferred Portfolio

Summary Portfolio Capacity by Resource Type and Year, Installed MW

Resource	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	Total
Expansion Options																				
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Peaking	-	-	-	-	-	395	(382)	-	-	-	-	-	(345)	(230)	836	-	3,122	749	-	4,145
DSM - Energy Efficiency	(69)	(48)	(37)	(40)	(27)	(17)	(37)	(415)	84	49	46	96	(25)	(301)	36	7	49	91	(112)	(670)
DSM - Demand Response	(1)	(54)	-	(98)	52	34	(4)	34	112	9	42	7	12	43	(125)	(19)	51	95	3	193
Renewable - Wind	-	(576)	-	(22)	(300)	(1,900)	443	5	1,169	994	-	-	228	662	-	-	-	-	-	703
Renewable - Utility Solar	-	(1,169)	(2,126)	171	(1,544)	(200)	369	5	(972)	449	(207)	-	-	1,118	-	-	-	-	14	(4,092)
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	(954)	(2,529)	(63)	(1,603)	(812)	-	521	21	(150)	3	-	152	1,494	-	-	17	9	-	(3,894)
Renewable - Battery (Long Duration)	-	-	-	-	-	-	-	-	-	(150)	-	-	-	(200)	-	-	-	-	-	(350)
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	(8)	-	-	-	-	-	-	-	-	-	-	-	-	-	8	-	-	-
Nuclear	-	-	-	-	-	-	-	-	(500)	(500)	-	-	-	-	-	-	-	-	-	(1,000)
Existing Unit Changes																				
Coal Plant Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	(909)	-	-		-	-	(909)
JB34 Gas Convert vs CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	699	-	(699)	-	-	(0)
Coal - SNCR	-	-	-	-	-	-	-	-	418	1,649	-	-	-	-	-	-		-	-	2,067
Total	**(70)**	**(2,801)**	**(4,700)**	**(52)**	**(3,422)**	**(2,500)**	**389**	**150**	**332**	**2,350**	**(116)**	**103**	**22**	**1,677**	**1,446**	**(12)**	**2,548**	**944**	**(95)**	

*For the compare, existing unit changes were consolidated for clarity

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Table 6.4 – 2023 IRP Update Summer Capacity Load and Resource Balance (Megawatts)

East	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Thermal	6,805	6,852	6,769	6,769	6,546	6,234	6,234	6,234	6,234	6,234
Peaker	352	352	352	352	352	352	352	352	352	0
Hydroelectric	60	60	60	60	60	60	60	60	60	60
Wind	504	716	701	701	701	701	681	649	649	649
Solar	279	356	600	595	591	586	582	578	574	570
Other Renewable	41	41	41	41	41	41	41	41	41	41
Storage	1	1	496	496	496	496	496	496	496	496
Purchase	120	120	120	120	120	120	120	120	120	120
Qualifying Facilities	359	358	356	354	352	350	348	346	343	334
Sale	0	0	0	0	0	0	0	0	0	0
East Existing Resources	**8,521**	**8,855**	**9,495**	**9,489**	**9,260**	**8,941**	**8,914**	**8,877**	**8,869**	**8,505**
Market Purchases										
Peaker	0	0	0	0	0	372	584	584	584	584
Wind	14	14	14	28	28	28	118	118	648	757
Solar	0	0	0	81	162	162	262	264	264	386
Other Renewable	0	0	0	0	0	0	0	0	0	0
Storage	0	0	0	245	428	608	608	684	694	694
Nuclear	0	0	0	0	0	0	485	485	485	485
East Planned Resources	**14**	**14**	**14**	**353**	**618**	**1,170**	**2,057**	**2,134**	**2,675**	**2,906**
East Total Resources	**8,534**	**8,869**	**9,509**	**9,842**	**9,877**	**10,111**	**10,971**	**11,011**	**11,544**	**11,411**
Load	7,679	7,947	7,877	8,137	8,556	8,727	8,906	9,181	8,972	9,105
Private Generation	(102)	(143)	(111)	(141)	(174)	(213)	(256)	(304)	(151)	(175)
Existing - Demand Response	(494)	(494)	(494)	(494)	(494)	(494)	(494)	(494)	(494)	(494)
New Demand Response	(5)	(33)	(55)	(63)	(112)	(122)	(122)	(142)	(161)	(161)
New Energy Efficiency	(132)	(217)	(269)	(343)	(450)	(534)	(614)	(743)	(814)	(932)
East Total obligation	**6,946**	**7,060**	**6,948**	**7,097**	**7,326**	**7,365**	**7,420**	**7,498**	**7,351**	**7,343**
East Reserve Margin	23%	26%	37%	39%	35%	37%	48%	47%	57%	55%
West										
Thermal	878	878	872	872	872	872	736	736	736	736
Peaker	0	0	0	0	0	0	0	0	0	0
Hydroelectric	691	695	692	700	700	699	699	699	699	699
Wind	56	56	56	56	56	56	56	56	56	56
Solar	54	54	54	53	53	53	53	52	52	52
Other Renewable	0	0	0	0	0	0	0	0	0	0
Purchase	0	0	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	146	193	192	192	191	190	190	190	183	183
Sale	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)
West Existing Resources	**1,818**	**1,868**	**1,860**	**1,866**	**1,866**	**1,864**	**1,727**	**1,726**	**1,720**	**1,719**
Market Purchases	1,413	1,235	508	256	478	348	0	0	0	0
Peaker	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	12	13	277	706
Solar	0	0	0	54	65	65	65	65	65	65
Other Renewable	0	0	0	0	0	0	0	0	0	0
Storage	0	0	27	218	280	376	376	680	688	688
Nuclear	0	0	0	0	0	0	0	0	0	0
West Planned Resources	**1,413**	**1,235**	**535**	**528**	**823**	**789**	**453**	**759**	**1,030**	**1,459**
West Total Resources	**3,231**	**3,103**	**2,395**	**2,394**	**2,688**	**2,653**	**2,180**	**2,485**	**2,750**	**3,178**
Load	3,667	3,842	3,931	4,111	4,257	4,466	4,593	4,817	4,813	4,870
Private Generation	(45)	(69)	(68)	(89)	(111)	(137)	(166)	(201)	(111)	(130)
Existing - Demand Response	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)
New Demand Response	(71)	(94)	(122)	(128)	(155)	(173)	(173)	(187)	(192)	(193)
New Energy Efficiency	(64)	(123)	(134)	(142)	(176)	(205)	(211)	(263)	(252)	(269)
West Total obligation	**3,466**	**3,535**	**3,586**	**3,731**	**3,794**	**3,931**	**4,022**	**4,144**	**4,237**	**4,257**
West Reserve Margin	-7%	-12%	-33%	-36%	-29%	-33%	-46%	-40%	-35%	-25%
System										
Total Resources	11,766	11,972	11,904	12,236	12,566	12,764	13,152	13,496	14,293	14,589
Obligation	10,412	10,595	10,534	10,828	11,120	11,295	11,442	11,642	11,588	11,600
Planning Reverve Margin (13%)	1,354	1,377	1,369	1,408	1,446	1,468	1,487	1,513	1,506	1,508
Obligation + Reserves	11,766	11,972	11,904	12,236	12,566	12,764	12,930	13,155	13,094	13,108
System Position	0	0	0	0	0	0	222	340	1,199	1,480
Reserve Margin	**13%**	**13%**	**13%**	**13%**	**13%**	**13%**	**15%**	**16%**	**23%**	**26%**

Table 6.4 (Cont.) – 2023 IRP Update Summer Capacity Load and Resource Balance (Megawatts)

East	2034	2035	2036	2037	2038	2039	2040	2041	2042
Thermal	6,234	6,234	6,234	4,802	4,104	4,104	2,890	2,890	2,890
Peaker	0	0	0	0	0	0	0	0	0
Hydroelectric	60	60	60	60	60	59	60	60	60
Wind	649	649	649	649	649	649	649	547	547
Solar	567	563	559	525	521	518	515	511	508
Other Renewable	41	41	41	41	13	13	13	13	13
Storage	495	495	495	495	495	495	495	495	495
Purchase	120	120	120	120	120	120	120	120	120
Qualifying Facilities	330	328	323	272	270	263	262	261	259
Sale	0	0	0	0	0	0	0	0	0
East Existing Resources	**8,496**	**8,490**	**8,481**	**6,965**	**6,233**	**6,221**	**5,003**	**4,897**	**4,892**
Market Purchases	0	0	0	0	0	0	0	0	0
Peaker	584	584	584	640	1,429	1,429	4,377	5,084	5,084
Wind	757	757	757	814	814	814	814	814	814
Solar	411	411	411	715	715	715	715	715	718
Other Renewable	0	0	0	0	0	0	0	0	0
Storage	695	695	705	1,484	1,484	1,484	1,484	1,484	1,484
Nuclear	485	485	485	485	485	485	485	485	485
East Planned Resources	**2,933**	**2,933**	**2,943**	**4,138**	**4,928**	**4,928**	**7,876**	**8,583**	**8,586**
East Total Resources	**11,429**	**11,423**	**11,424**	**11,103**	**11,161**	**11,149**	**12,879**	**13,479**	**13,477**
Load	9,223	9,361	9,564	9,726	9,867	9,980	10,112	10,248	10,428
Private Generation	(197)	(220)	(242)	(265)	(287)	(309)	(330)	(352)	(374)
Existing - Demand Response	(494)	(494)	(494)	(494)	(494)	(494)	(494)	(494)	(494)
New Demand Response	(178)	(186)	(194)	(224)	(261)	(261)	(283)	(349)	(349)
New Energy Efficiency	(1,037)	(1,124)	(1,209)	(1,317)	(1,400)	(1,498)	(1,589)	(1,653)	(1,752)
East Total obligation	**7,317**	**7,338**	**7,424**	**7,425**	**7,425**	**7,418**	**7,416**	**7,400**	**7,459**
East Reserve Margin	56%	56%	54%	50%	50%	50%	74%	82%	81%
West									
Thermal	736	736	736	500	500	500	500	500	500
Peaker	0	0	0	0	0	0	0	0	0
Hydroelectric	699	699	699	699	699	699	699	699	707
Other Renewable	0	0	0	0	0	0	0	0	0
Purchase	0	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0	0
Qualifying Facilities	182	182	181	162	160	159	159	158	159
Sale	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)
West Existing Resources	**1,611**	**1,610**	**1,610**	**1,354**	**1,352**	**1,351**	**1,351**	**1,350**	**1,360**
Market Purchases	0	0	0	0	0	0	0	0	0
Peaker	0	0	0	0	0	0	0	0	0
Wind	706	706	743	952	952	952	952	952	952
Solar	65	65	65	65	65	65	65	65	65
Other Renewable	0	0	0	0	0	0	0	0	0
Storage	688	688	787	1,345	1,345	1,345	1,365	1,372	1,372
Nuclear	0	0	0	0	0	0	0	0	0
West Planned Resources	**1,459**	**1,459**	**1,595**	**2,362**	**2,362**	**2,362**	**2,383**	**2,389**	**2,389**
West Total Resources	**3,070**	**3,070**	**3,205**	**3,716**	**3,714**	**3,713**	**3,733**	**3,739**	**3,749**
Load	4,929	4,995	5,068	5,176	5,246	5,318	5,384	5,461	5,647
Private Generation	(148)	(163)	(178)	(193)	(208)	(222)	(236)	(250)	(264)
Existing - Demand Response	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)
New Demand Response	(200)	(201)	(202)	(206)	(229)	(229)	(257)	(264)	(265)
New Energy Efficiency	(299)	(322)	(314)	(357)	(355)	(366)	(396)	(391)	(429)
West Total obligation	**4,261**	**4,288**	**4,353**	**4,399**	**4,433**	**4,481**	**4,474**	**4,535**	**4,668**
West Reserve Margin	-28%	-28%	-26%	-16%	-16%	-17%	-17%	-18%	-20%
System									
Total Resources	14,499	14,492	14,629	14,819	14,875	14,862	16,612	17,219	17,226
Obligation	11,578	11,626	11,778	11,825	11,858	11,899	11,889	11,935	12,127
Planning Reverve Margin (13%)	1,505	1,511	1,531	1,537	1,541	1,547	1,546	1,552	1,577
Obligation + Reserves	13,083	13,137	13,309	13,362	13,399	13,446	13,435	13,487	13,704
System Position	1,416	1,356	1,320	1,458	1,476	1,416	3,177	3,732	3,522
Reserve Margin	**25%**	**25%**	**24%**	**25%**	**25%**	**25%**	**40%**	**44%**	**42%**

Table 6.5 – 2023 IRP Update Winter Capacity Load and Resource Balance (Megawatts)

East	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Thermal	6,828	6,875	6,795	6,795	6,578	6,264	6,264	6,264	6,264	6,264
Peaker	323	323	323	323	323	323	323	323	323	0
Hydroelectric	36	36	36	36	36	36	36	36	36	36
Wind	442	602	594	594	594	594	579	552	552	552
Solar	197	288	408	405	402	399	396	393	391	388
Other Renewable	34	34	34	34	34	34	34	34	34	34
Storage	1	1	468	468	468	468	468	468	468	468
Purchase	172	172	172	172	172	172	172	172	172	172
Qualifying Facilities	284	283	281	279	278	276	275	273	271	263
Sale	0	0	0	0	0	0	0	0	0	0
East Existing Resources	**8,317**	**8,613**	**9,111**	**9,107**	**8,884**	**8,566**	**8,547**	**8,515**	**8,510**	**8,177**
Market Purchases	0	0	0	0	0	0	0	0	0	0
Peaker	0	0	0	0	0	372	584	584	584	584
Wind	50	51	51	66	66	66	141	141	640	737
Solar	0	0	0	50	109	109	187	188	188	284
Other Renewable	0	0	0	0	0	0	0	0	0	0
Storage	0	0	0	259	432	602	602	686	696	696
Nuclear	0	0	0	0	0	0	475	475	475	475
East Planned Resources	**50**	**51**	**51**	**376**	**608**	**1,150**	**1,990**	**2,075**	**2,583**	**2,776**
East Total Resources	**8,367**	**8,664**	**9,163**	**9,482**	**9,492**	**9,717**	**10,537**	**10,590**	**11,093**	**10,953**
Load	5,724	6,097	6,171	6,444	6,754	6,700	6,872	7,145	7,214	7,387
Private Generation	(2)	0	0	0	0	(8)	(10)	0	0	0
Existing - Demand Response	(462)	(462)	(462)	(462)	(462)	(462)	(462)	(462)	(462)	(462)
New Demand Response	(5)	(20)	(35)	(39)	(66)	(72)	(72)	(84)	(97)	(97)
New Energy Efficiency	(102)	(111)	(172)	(232)	(299)	(470)	(569)	(529)	(615)	(693)
East Total obligation	**5,154**	**5,504**	**5,502**	**5,711**	**5,927**	**5,688**	**5,759**	**6,070**	**6,040**	**6,135**
East Reserve Margin	62%	57%	67%	66%	60%	71%	83%	74%	84%	79%
West										
Thermal	878	878	874	874	874	874	736	736	736	736
Peaker	0	0	0	0	0	0	0	0	0	0
Hydroelectric	538	544	542	555	556	555	555	553	554	554
Wind	74	74	74	74	74	74	74	74	74	74
Solar	44	43	43	43	42	42	42	41	40	40
Other Renewable	0	0	0	0	0	0	0	0	0	0
Renewable	0	0	0	0	0	0	0	0	0	0
Purchase	1	1	1	1	1	1	1	1	1	1
Qualifying Facilities	116	127	127	127	127	126	126	126	120	120
Sale	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)
West Existing Resources	**1,639**	**1,657**	**1,650**	**1,662**	**1,662**	**1,660**	**1,522**	**1,520**	**1,514**	**1,513**
Market Purchases	0	0	0	0	0	0	0	0	0	0
Peaker	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	11	12	256	617
Solar	0	0	0	41	48	48	48	48	48	48
Other Renewable	0	0	0	0	0	0	0	0	0	0
Storage	0	0	27	250	324	441	441	837	846	846
Nuclear	0	0	0	0	0	0	0	0	0	0
West Planned Resources	**0**	**0**	**27**	**291**	**372**	**489**	**500**	**897**	**1,151**	**1,511**
West Total Resources	**1,639**	**1,657**	**1,676**	**1,953**	**2,034**	**2,149**	**2,022**	**2,417**	**2,665**	**3,024**
Load	3,711	3,577	3,676	3,858	4,024	4,476	4,539	4,419	4,475	4,524
Private Generation	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Existing - Demand Response	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
New Demand Response	(60)	(78)	(98)	(101)	(131)	(165)	(165)	(180)	(182)	(184)
New Energy Efficiency	(89)	(96)	(126)	(167)	(221)	(324)	(378)	(341)	(368)	(415)
West Total obligation	**3,551**	**3,392**	**3,442**	**3,580**	**3,661**	**3,977**	**3,986**	**3,888**	**3,913**	**3,914**
West Reserve Margin	-54%	-51%	-51%	-45%	-44%	-46%	-49%	-38%	-32%	-23%
System										
Total Resources	10,006	10,321	10,839	11,436	11,527	11,866	12,559	13,006	13,758	13,977
Obligation	8,705	8,896	8,944	9,291	9,589	9,665	9,745	9,957	9,953	10,049
Planning Reverve Margin (13%)	1,132	1,157	1,163	1,208	1,247	1,256	1,267	1,294	1,294	1,306
Obligation + Reserves	9,837	10,053	10,107	10,499	10,835	10,922	11,012	11,252	11,247	11,355
System Position	170	268	732	936	691	945	1,547	1,755	2,511	2,622
Reserve Margin	**15%**	**16%**	**21%**	**23%**	**20%**	**23%**	**29%**	**31%**	**38%**	**39%**

Table 6.5 (Cont.) - 2023 IRP Update Winter Capacity Load and Resource Balance (Megawatts)

East	2034	2035	2036	2037	2038	2039	2040	2041	2042
Thermal	6,264	6,264	6,264	4,815	4,117	4,117	2,854	2,854	2,854
Peaker	0	0	0	0	0	0	0	0	0
Hydroelectric	36	36	36	36	36	36	36	36	36
Wind	552	552	552	552	552	552	552	470	470
Solar	385	383	380	357	354	352	350	347	345
Other Renewable	34	34	34	34	8	8	8	8	8
Storage	467	467	467	467	467	467	467	467	467
Purchase	172	172	172	172	172	172	172	172	172
Qualifying Facilities	259	257	254	213	212	207	206	205	204
Sale	0	0	0	0	0	0	0	0	0
East Existing Resources	**8,169**	**8,165**	**8,159**	**6,645**	**5,918**	**5,911**	**4,645**	**4,560**	**4,556**
Market Purchases	0	0	0	0	0	0	0	0	0
Peaker	584	584	584	640	1,429	1,429	4,385	5,092	5,092
Wind	737	737	737	782	782	782	782	782	738
Solar	303	303	303	540	540	540	540	540	554
Other Renewable	0	0	0	0	0	0	0	0	0
Storage	698	698	709	1,556	1,556	1,556	1,556	1,556	1,556
Nuclear	475	475	475	475	475	475	475	475	475
East Planned Resources	**2,797**	**2,797**	**2,808**	**3,993**	**4,782**	**4,782**	**7,738**	**8,445**	**8,414**
East Total Resources	**10,966**	**10,962**	**10,967**	**10,638**	**10,700**	**10,693**	**12,383**	**13,005**	**12,971**
Load	7,329	7,518	7,607	7,745	7,870	8,007	8,186	8,326	8,472
Private Generation	(19)	(21)	(23)	(25)	(28)	(30)	(32)	(0)	(36)
Existing - Demand Response	(462)	(462)	(462)	(462)	(462)	(462)	(462)	(462)	(462)
New Demand Response	(109)	(114)	(120)	(143)	(210)	(210)	(231)	(270)	(270)
New Energy Efficiency	(1,024)	(1,147)	(1,263)	(1,464)	(1,573)	(1,658)	(1,743)	(1,868)	(2,048)
East Total obligation	**5,715**	**5,774**	**5,738**	**5,651**	**5,598**	**5,648**	**5,719**	**5,726**	**5,655**
East Reserve Margin	92%	90%	91%	88%	91%	89%	117%	127%	129%
West									
Thermal	736	736	736	499	499	499	499	499	499
Peaker	0	0	0	0	0	0	0	0	0
Hydroelectric	554	554	554	554	554	554	554	554	565
Storage	0	0	0	0	0	0	0	0	0
Renewable	0	0	0	0	0	0	0	0	0
Purchase	1	1	1	1	1	1	1	1	1
Qualifying Facilities	120	120	119	105	104	103	103	103	103
Sale	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)
West Existing Resources	**1,399**	**1,399**	**1,399**	**1,147**	**1,147**	**1,146**	**1,146**	**1,145**	**1,157**
Market Purchases	0	0	0	0	0	0	0	0	0
Peaker	0	0	0	0	0	0	0	0	0
Wind	617	617	653	808	808	808	808	808	789
Solar	48	48	48	48	48	48	48	48	48
Other Renewable	0	0	0	0	0	0	0	0	0
Storage	847	847	975	1,701	1,701	1,701	1,724	1,732	1,732
Nuclear	0	0	0	0	0	0	0	0	0
West Planned Resources	**1,512**	**1,512**	**1,677**	**2,557**	**2,557**	**2,557**	**2,581**	**2,588**	**2,570**
West Total Resources	**2,911**	**2,911**	**3,076**	**3,705**	**3,704**	**3,703**	**3,726**	**3,734**	**3,726**
Load	4,770	4,917	4,986	4,938	5,058	5,133	5,273	5,285	5,394
Private Generation	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Existing - Demand Response	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
New Demand Response	(197)	(198)	(199)	(208)	(225)	(225)	(244)	(249)	(250)
New Energy Efficiency	(588)	(634)	(678)	(720)	(755)	(801)	(844)	(838)	(943)
West Total obligation	**3,975**	**4,074**	**4,098**	**4,000**	**4,068**	**4,096**	**4,174**	**4,187**	**4,190**
West Reserve Margin	-27%	-29%	-25%	-7%	-9%	-10%	-11%	-11%	-11%
System									
Total Resources	13,877	13,873	14,043	14,342	14,404	14,396	16,110	16,739	16,697
Obligation	9,690	9,847	9,836	9,651	9,666	9,744	9,893	9,913	9,846
Planning Reverve Margin (13%)	1,260	1,280	1,279	1,255	1,257	1,267	1,286	1,289	1,280
Obligation + Reserves	10,950	11,128	11,115	10,905	10,922	11,010	11,179	11,202	11,126
System Position	2,928	2,745	2,928	3,437	3,482	3,386	4,931	5,537	5,572
Reserve Margin	**43%**	**41%**	**43%**	**49%**	**49%**	**48%**	**63%**	**69%**	**70%**

Carbon Dioxide Emissions

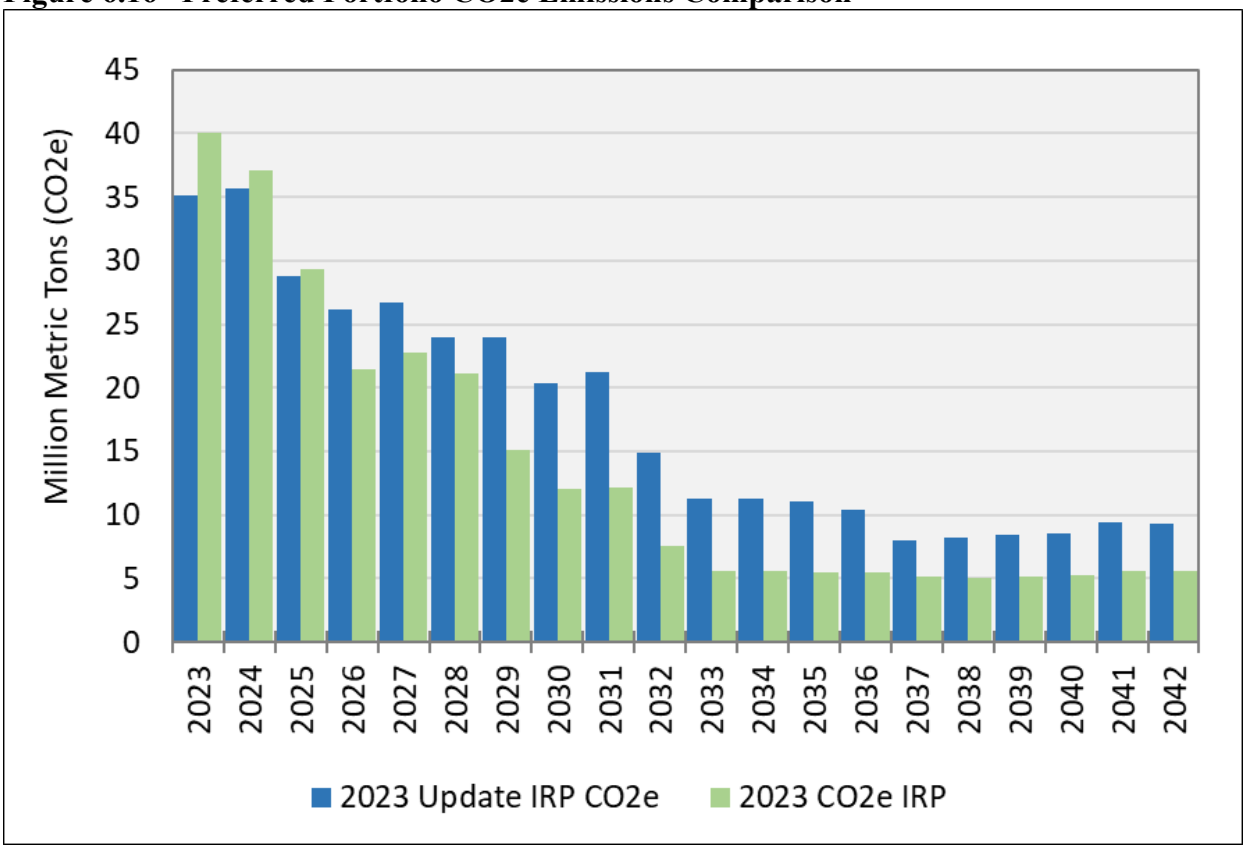
The 2023 IRP Update preferred portfolio reflects PacifiCorp's on-going efforts to provide valuable energy solutions for our customers that reflects a continued trajectory of declining carbon dioxide (CO_2) and other carbon dioxide equivalent (CO_2e) emissions resulting in a measure of total emissions.

PacifiCorp's emissions have been declining and continue to decline related to several factors including PacifiCorp's participation in the EIM and commitment to CAISO's Extended Day-Ahead Market (EDAM), which reduces customer costs and maximizes use of non-emitting renewable resources that have no fuel cost and that generate tax credits.

The chart below in Figure 6.16 compares projected annual CO_2e emissions between the 2023 IRP Update and 2023 IRP preferred portfolios. In this graph, emissions are assigned to market purchases at a rate of 0.428 metric tons CO_2 equivalent per megawatt-hour.

In the 2023 IRP Update, emissions are higher than projected in the 2023 IRP starting in 2026. Removal of the OTR, which limited summer generation from gas and coal-fueled resources, is a significant driver. Further, over the longer-term the load forecast in the 2023 IRP Update is higher than in the 2023 IRP. Importantly, the 2023 IRP Update preferred portfolio continues to show a continued downward trajectory in emissions over time. By 2030, average annual CO_2e emissions in the 2023 IRP Update preferred portfolio are reduced by 63% against the year 2005 baseline versus a reduction of 78% against the baseline in the 2023 IRP preferred portfolio. By the end of the planning horizon, system CO_2e emissions are projected to fall from 35.1 million metric tons in 2023 to 9.3 million tons in 2042—a reduction of 73.5%.

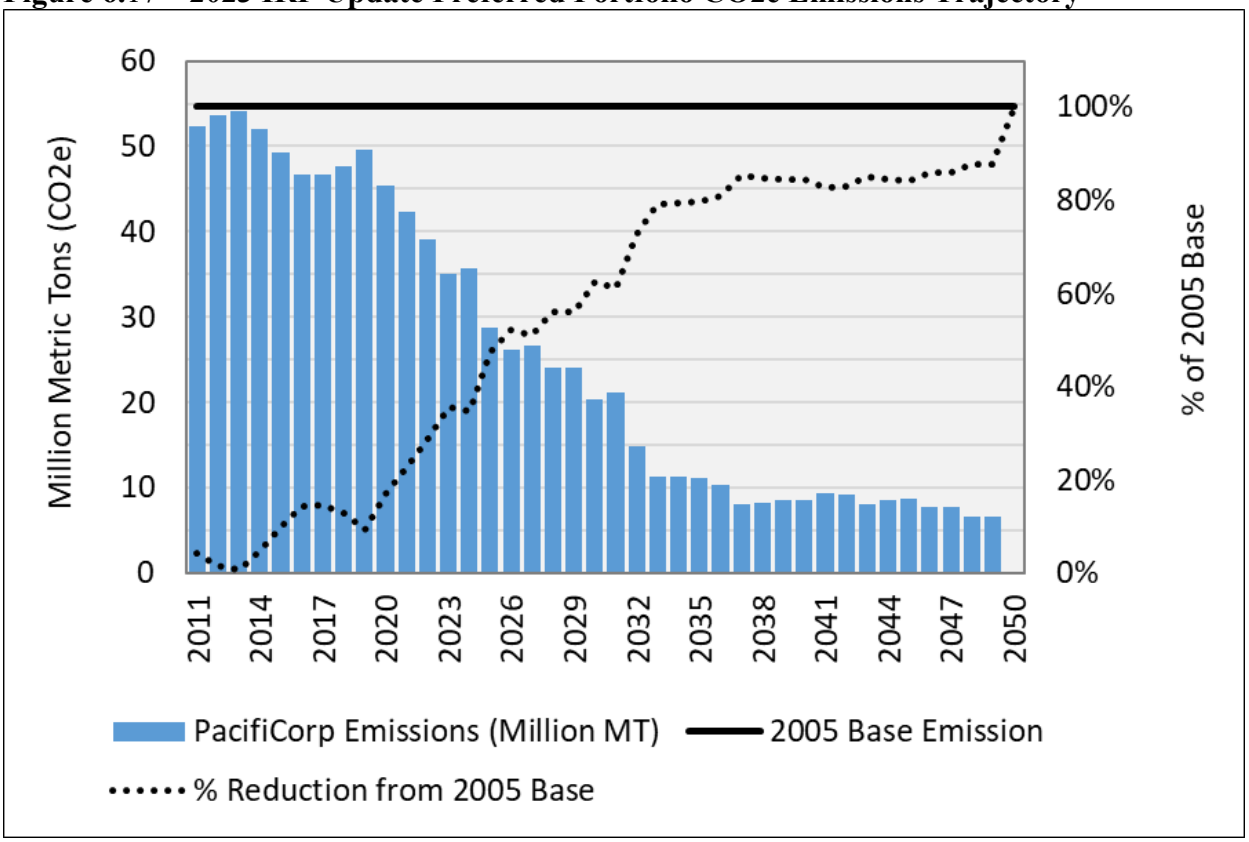
Figure 6.16 –Preferred Portfolio CO2e Emissions Comparison*



* PacifiCorp CO_2 equivalent emissions trajectory reflects actual emissions through 2022 from owned facilities, specified sources and unspecified sources. From 2023 through the end of the twenty-year planning period in 2042, emissions reflect those from the 2023 IRP Update preferred portfolio with emissions from specified sources reported in CO_2 equivalent. Market purchases are assigned a default emission factor (0.428 metric tons CO_2e/megawatt-hour). Emissions from sales are not removed. Beyond 2042, emissions reflect the rolling average emissions of each resource from the 2023 IRP update preferred portfolio through the life of the resource.

Figure 6.17 includes historical data, assigns emissions at a rate of 0.428 metric tons CO_2 equivalent per megawatt-hour to market purchases (with no credit to market sales), includes emissions associated with specified purchases, and extrapolates projections out through 2050. This graph demonstrates that relative to a 2005 baseline, of 54.6 million metric tons, system CO_2e emissions are down 47% in 2025, 63% in 2030, 80% in 2035, 84% in 2040, 84% in 2045, and 100% in 2050 (assuming that by 2050, new gas-fired resources added in the preferred portfolio are fueled with a non-emitting fuel alternative.

Figure 6.17 – 2023 IRP Update Preferred Portfolio CO2e Emissions Trajectory*



* The emissions trajectory does not incorporate clean energy targets set forth in Oregon House Bill 2021 or any other state-specific emissions trajectories.

Oregon and Washington Emissions Compliance

The 2023 IRP Update addresses modeled policy outcomes for Oregon's Clean Energy Plan and the Washington Clean Energy Implementation Plan. Circumstances contributing to emissions with these two legislative actions have changed since the 2023 IRP. To the extent systemwide planning drivers have reduced the overall pressure toward renewables procurement and emissions reductions, this places upward pressure on the magnitude and cost of activity that will be required for both Oregon and Washington compliance.

For example, EPA's approval of Wyoming's OTR plan and the stay of EPA's disapproval of Utah's OTR plan means that federally mandated compliance obligations which drove renewable resource procurement via restrictions on NOx emissions from coal and gas-fired units that were included in the 2023 IRP are now lessened. Consequently, additional renewables are indicated for Oregon and Washington portfolios compared to what has been most recently presented in PacifiCorp's CEP and CEIP biennial reports, respectively. Where federal law dictates compliance action that is aligned with Oregon and Washington legislative goals, the costs and benefits are shared among all customers. However, where state legislation specifically drives alternative procurements, the costs and benefits of those procurements will fall to the individual states and their customers. The process of integrating state level requirements into the preferred portfolio is discussed at length in preceding sections.

At this time, PacifiCorp continues to anticipate that allocations and the multistate process will play a significant role in achieving final compliance with Oregon HB 2021 and Washington CETA requirements.

Renewable Portfolio Standards

Figure 6.18 shows PacifiCorp's renewable portfolio standard (RPS) compliance forecast for California, Oregon, and Washington after accounting for new renewable resources in the 2023 IRP Update preferred portfolio. While these resources are included in the preferred portfolio as cost-effective system resources and are not included to specifically meet RPS targets, they nonetheless contribute to meeting RPS targets in PacifiCorp's western states.

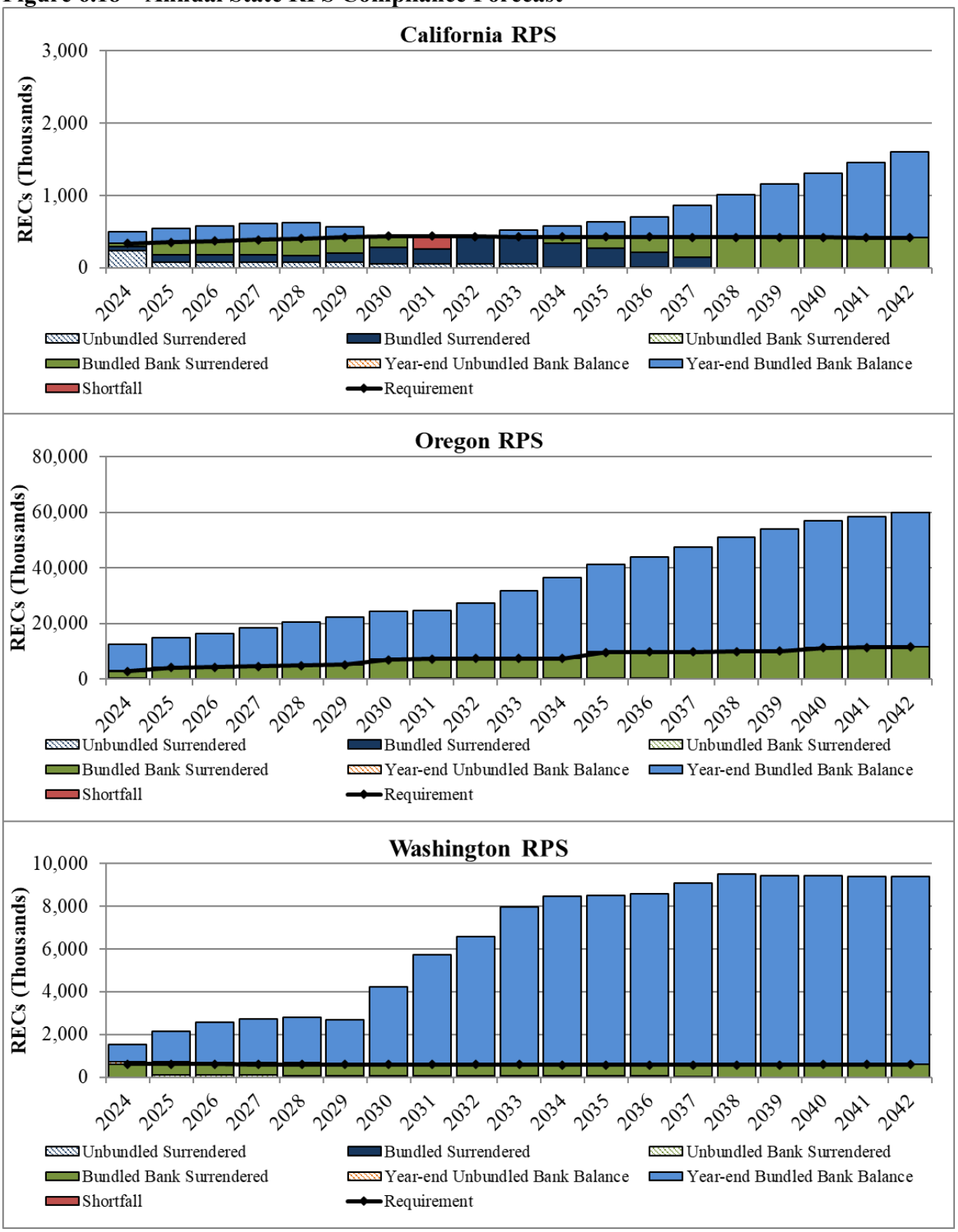
The California RPS compliance position will be met through year 2030 with owned and contracted renewable resources, as well as REC purchases. Beyond 2030, the company may need to purchase approximately ~175,000 RECs per year to meet the RPS target of 60% in years where a shortfall is projected.

Oregon RPS compliance is achieved through 2042 with the addition of new renewable resources in the 2023 IRP Update preferred portfolio.

Under PacifiCorp's 2020 Protocol and the Washington Interjurisdictional Allocation Methodology, Washington's RPS position is improved by receiving a system share of renewable resources across PacifiCorp's system, and there are no anticipated shortfalls.

While not shown in Figure 6.18, PacifiCorp meets the Utah 2025 state target to supply 20% of adjusted retail sales with eligible renewable resources with existing owned and contracted resources and new renewable resources.

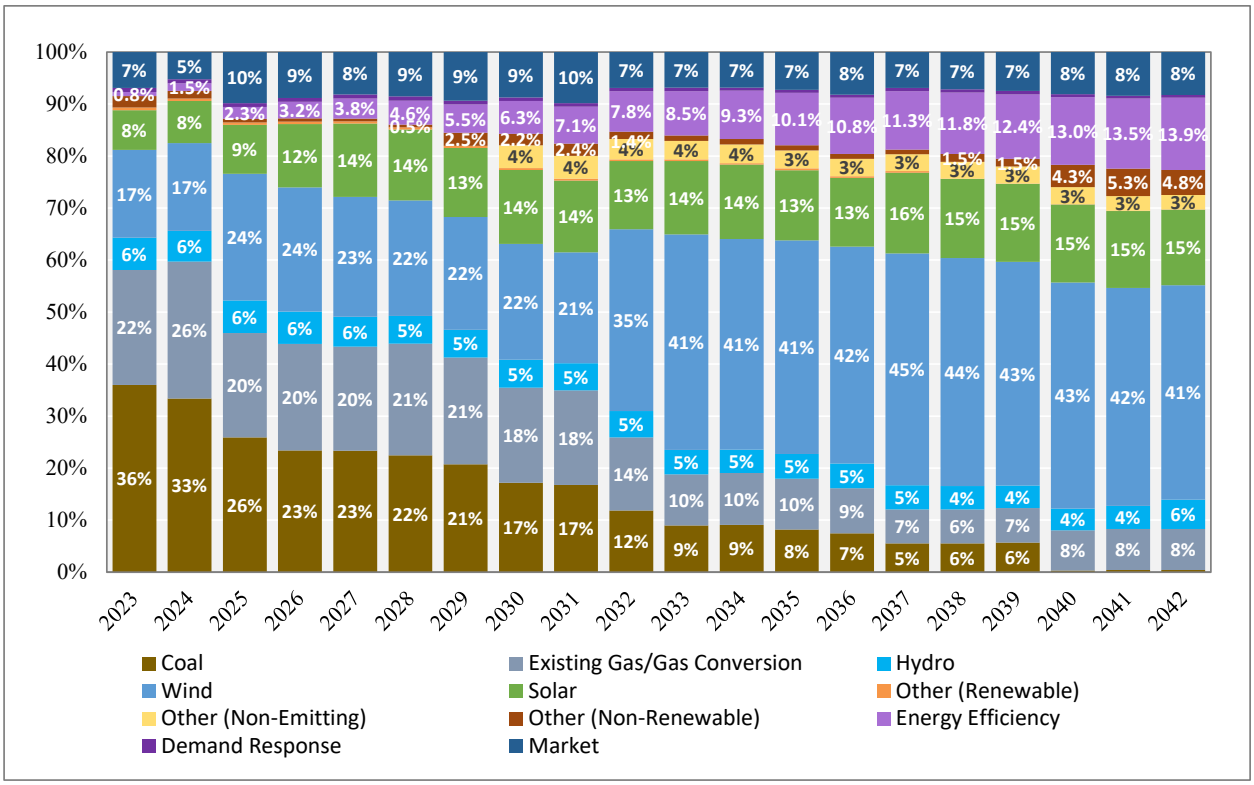
Figure 6.18 – Annual State RPS Compliance Forecast



Projected Energy Mix

Figure 6.19 reports projected changes to PacifiCorp's system energy mix over time, based upon preferred portfolio outcomes in the short-term (ST) model.[2] On an energy basis, coal generation drops to 22% by 2028, falls to 12% by 2032, and declines to less than 1% by year 2040. Reduced energy from coal is offset primarily by increased energy from renewable resources, nuclear resources, DSM, and to a smaller extent later in the plan, peaking resources.

Figure 6.19 – Projected Energy Mix with Preferred Portfolio Resources*

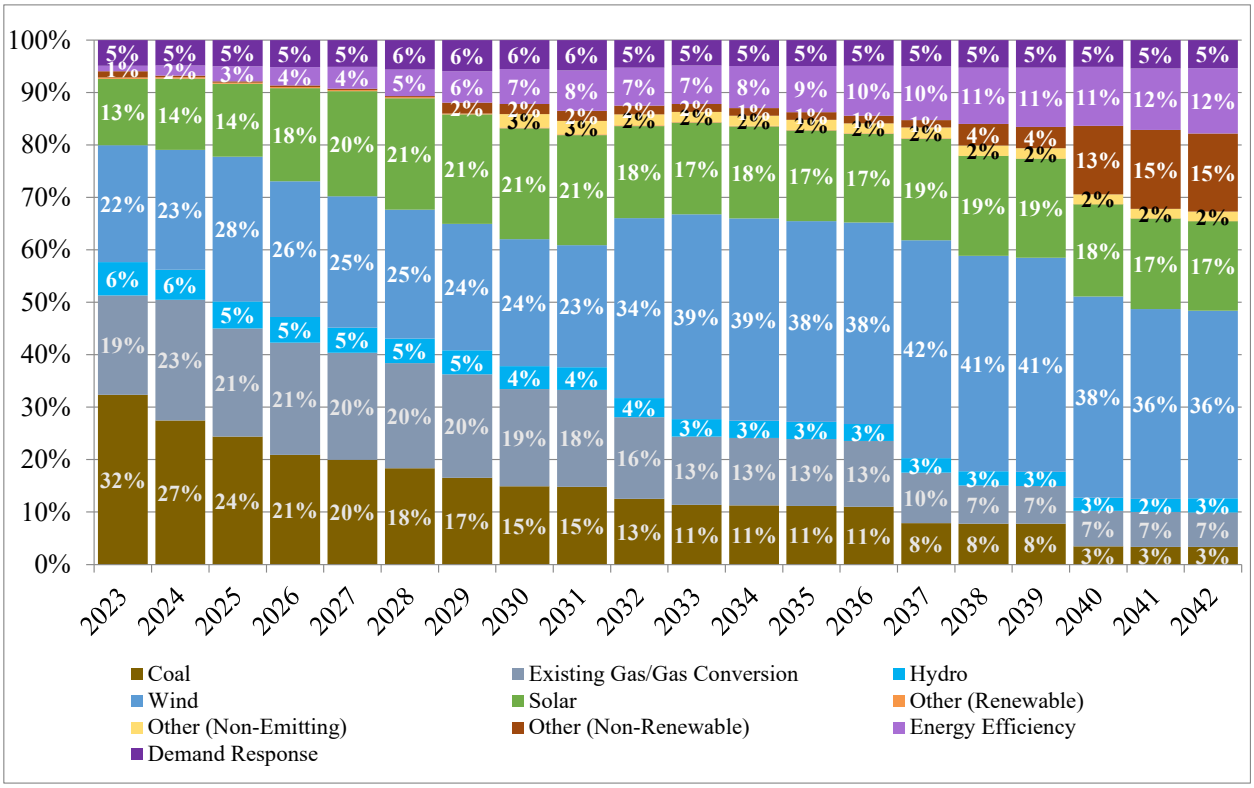


* Storage resources are excluded as they do not provide net energy.

Figure 6.20 shows how PacifiCorp's capacity mix is expected to change over time. Coal capacity drops to 18% of the system in 2028, then further to 11% of the system starting in 2033, and finally to 3% of capacity in 2040. Coal capacity is primarily replaced by renewables that increase in contribution over time. Towards the end of the study period, "other (Non-Renewable)" (mostly new peaking) capacity begins to contribute a larger percentage of system capacity.

[2]The projected PacifiCorp 2023 IRP update preferred portfolio "energy mix" is based on energy production and not resource capability, capacity or delivered energy. All or some of the renewable energy attributes associated with solar, wind, biomass, biogas, geothermal and qualifying hydro facilities in PacifiCorp's energy mix may be: (a) used in future years to comply with renewable portfolio standards or other regulatory requirements; (b) sold to third parties in the form of renewable energy credits or other environmental commodities; or (c) excluded from energy purchased. PacifiCorp's 2023 IRP update preferred portfolio energy mix includes owned resources and purchases from third parties.

Figure 6.20 – Projected Capacity Mix with 2023 IRP Update Preferred Portfolio Resources*



* Storage resources are excluded as they do not provide net capacity.

Additional Studies

In addition to the 2023 IRP Update preferred portfolio, PacifiCorp developed key variants of the updated preferred portfolio, focusing on critical decision variables addressing significant areas of interest and change. The economics of these studies further supports their value in the 2023 IRP Update preferred portfolio as the least-cost, least-risk portfolio. In addition, PacifiCorp is including the Oregon and Washington standalone Compliance studies within this section to provide clarity about the decisions made for the whole system in order to comply with Oregon or Washington.

The variant portfolios are summarized in Table 6.6. Like the preferred portfolio, all variant studies were taken through the iterative modeling process described earlier in this chapter. Each variant was subject to granularity adjustments and reliability load additions files specific to the portfolio selected by the model for the variant conditions. For the No-Nuclear and all Jim Bridger 3 & 4 variants, the same process was undertaken to incorporate changes to the preferred portfolio as was completed to integrate Oregon and Washington compliance. Because the overall change in these portfolios is not a wholesale baseline change of assumptions, but merely an "in vs. out" (nuclear) or "configuration vs. configuration" study this process was deemed appropriate. For the Offshore Wind and Utah participation in OTR starting in 2027 studies, the base of the model is very different, resulting in changes to the portfolio that were not incorporated into the preferred portfolio, but left to stand alone.

Table 6.6 – Variant Portfolios

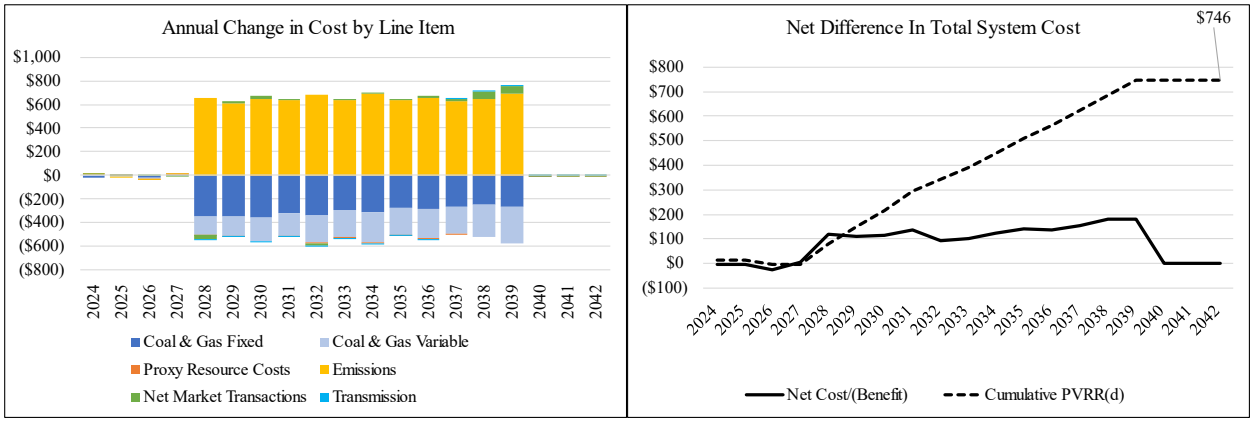
Case	Description
No CCUS	Counterfactual to Preferred Portfolio where Jim Bridger 3 and 4 run as coal
Bridger 3&4 Gas Convert	Counterfactual to Preferred Portfolio where Jim Bridger 3 and 4 convert to gas in 2030
No Nuclear	Counterfactual to Preferred Portfolio where Natrium project is not allowed
Utah OTR Participation	Study to evaluate portfolio selections if Utah OTR Stay order is overturned
Offshore Wind	Study to evaluate portfolio if 1 gigawatt of offshore wind is required in Oregon
Oregon HB 2021	Study to evaluate impact to the entire system if Oregon policy needs were shared
Washington CETA	Study to evaluate impact to the entire system if Washington policy needs were shared

CCUS Variant (No CCUS)

The preferred portfolio selected Jim Bridger 3 and 4 to be converted to CCUS in 2028. Using the methodology described earlier in the chapter, the replacement for the CCUS was selected based on iterative model runs which remove the selection of CCUS. No other resources changes were selected in the absence of CCUS at Jim Bridger units 3 and 4. However, without CCUS these units retire two years earlier, as their operational life is not extended to capture additional ITC benefits.

Figure 6.21 below shows the change in system cost when CCUS at Jim Bridger is not installed, and Jim Bridger 3 and 4 operate as coal through 2037, resulting in a PVRR increase of $746m. This increase is almost entirely driven by the loss of tax credits associated with the CCUS unit. The increase in emissions cost is partially offset by lower fixed and variable costs on the gas converted units, but the loss of the tax credits far outweighs these savings.

Figure 6.21 – Increase/(Decrease) in System Costs when CCUS is Removed from the Preferred Portfolio



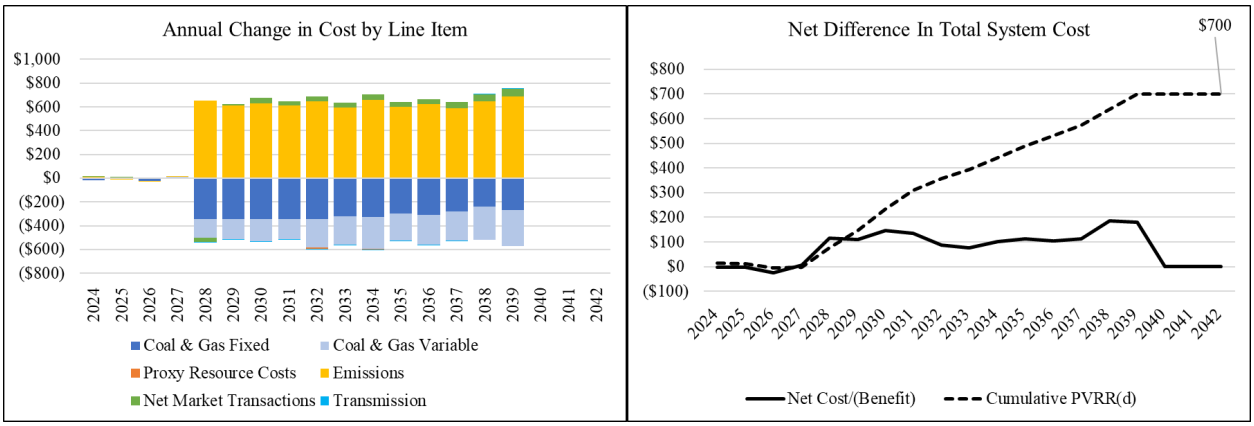
Jim Bridger 3 and 4 Gas Conversion Variant

The preferred portfolio selected Jim Bridger 3 and 4 to be converted to CCUS in 2028. Using the methodology described earlier in the chapter, evaluating Jim Bridger 3 and 4 as gas converted in 2030 was based on the iterative Jim Bridger 3&4 Gas Convert runs. Because no change to other resources at the Jim Bridger area were indicated by that run, the only change to this model was the

switch of Jim Bridger from CCUS to gas convert in 2030 and run through 2037, while the CCUS unit retires at year end 2039.

Figure 6.22 below shows the change in system cost when CCUS at Jim Bridger is replaced with a gas conversion of the unit in 2030, resulting in a PVRR increase of $700m. This increase is almost entirely driven by the loss of tax credits associated with the CCUS unit. The increase in emissions cost is partially offset by lower fixed and variable costs on the gas converted units, but the loss of the tax credits far outweighs these savings.

Figure 6.22 – Increase/(Decrease) in System Cost Assuming Jim Bridger 3 and 4 Gas Conversion



Nuclear Variant (No Nuclear)

The preferred portfolio included the Natrium demonstration project at Naughton. Using the methodology described earlier in the chapter, evaluating replacement options for the Natrium Demonstration project was completed using the iterative No Nuclear runs. In those views, gas peaking units replaced the nuclear capacity at Naughton. As a result, this change was incorporated as the replacement for the Natrium demonstration project.

Figure 6.23 – Increase/(Decrease) in Proxy Resources when the Natrium™ Demonstration Project is Removed

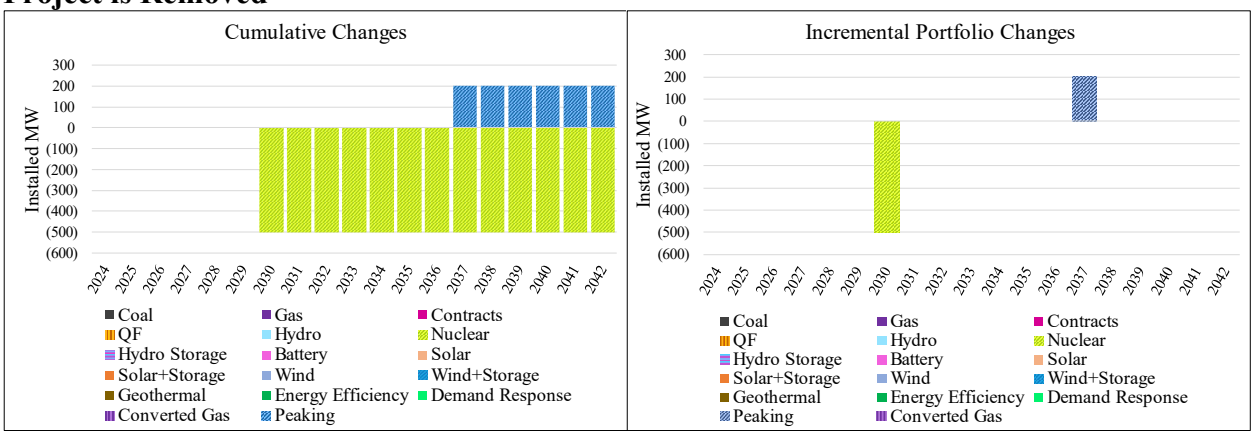
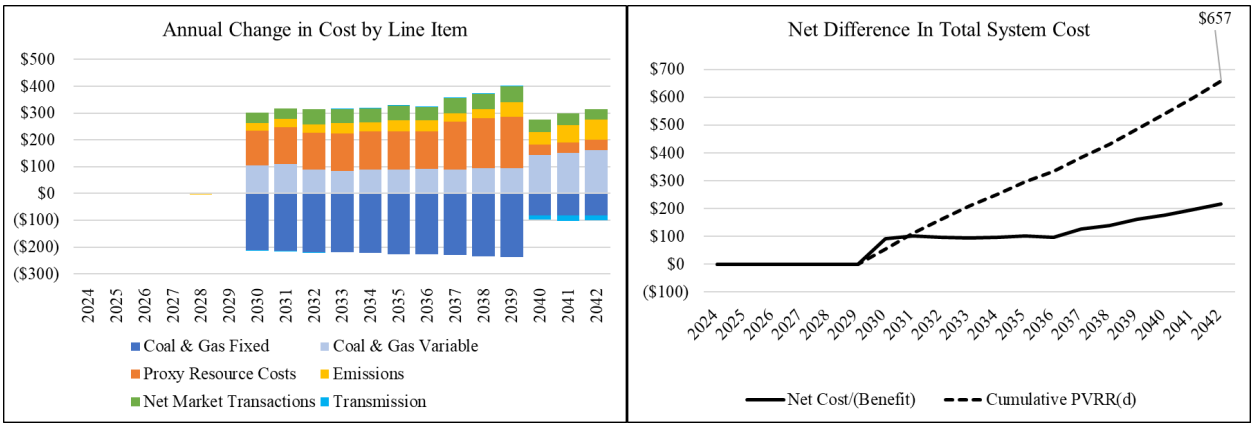


Figure 6.24 below shows the change in system cost when the Natrium project is removed and replaced with a peaking unit in 2037, resulting in a $657m dollar increase in the PVRR of the portfolio. In 2030 when the Natrium plant is removed from the portfolio, proxy resource costs begin to increase as new resources added to the portfolio before 2030 begin to operate differently. Coal and gas variable costs and corresponding emissions costs also increase as the system relies more heavily on those resources for reliability.

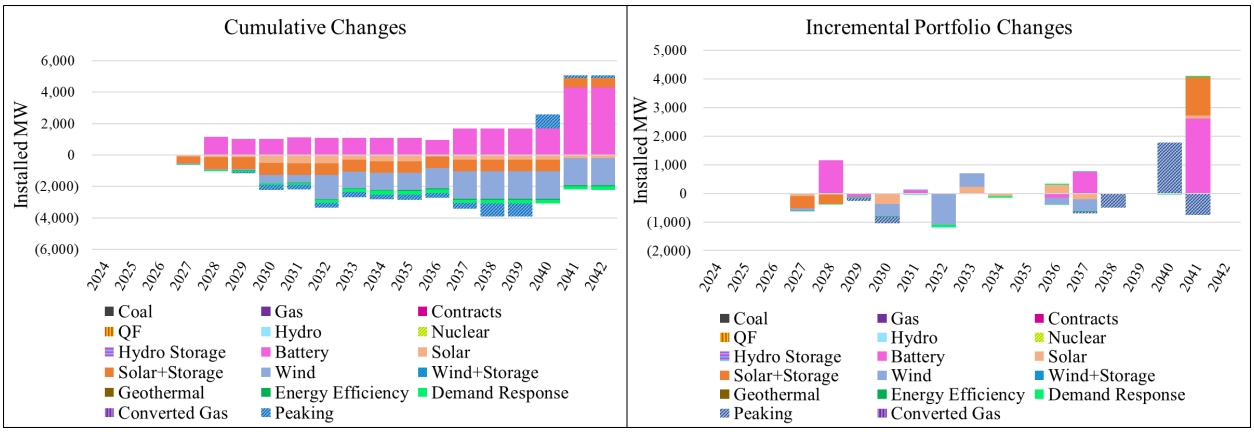
Figure 6.24 – Increase/(Decrease) in System Costs when Nuclear is Removed from the Preferred Portfolio



Utah Stay OTR Variant

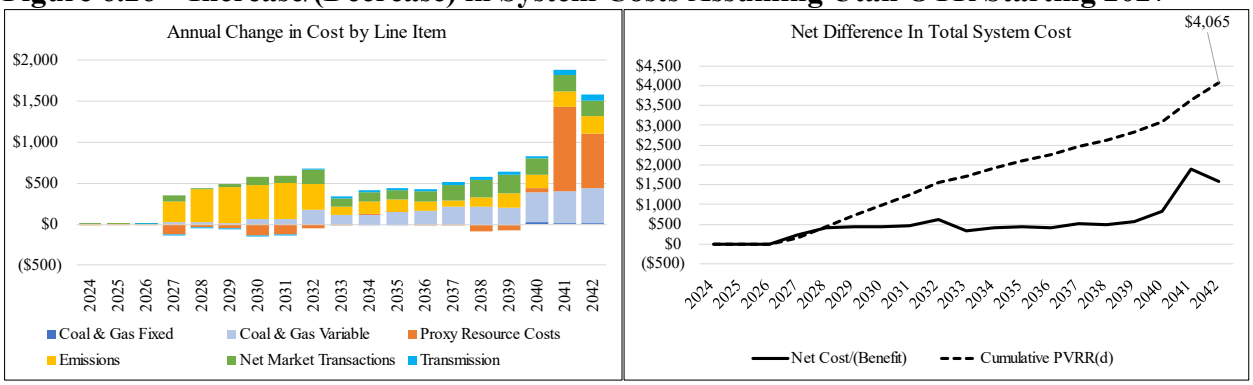
This variant allowed the model to select any portfolio of resources with the assumption that Utah would be subject to an OTR constraint starting in 2027. The significant reduction in the ability for coal units to operate led to a much larger selection of battery storage resources. Additionally, the portfolio relies more heavily on gas production than the preferred portfolio.

Figure 6.25 – Increase/(Decrease) in Proxy Resources when Utah OTR starting in 2027 is assumed



As seen below in Figure 6.26, the addition of the Utah OTR starting in 2027 assumption increases costs to the system by $4.1b. This higher cost is attributed mostly to higher emission costs in the years 2027 through 2032, and proxy resource costs in 2041 and 2042.

Figure 6.26 – Increase/(Decrease) in System Costs Assuming Utah OTR Starting 2027



Oregon Offshore Wind Variant

As seen below in Figure 6.27, the requirement for the model to build offshore wind in 2032 off the coast of southern Oregon results in large changes to the portfolio. Additional battery is selected early while Oregon and Washington situs resources and the early cluster resources are not selected. Because of the differing capacity factor of offshore wind, less overall onshore wind and solar are selected.

Figure 6.27 – Increase/(Decrease) in Proxy Resources Assuming Oregon Offshore Wind is Selected

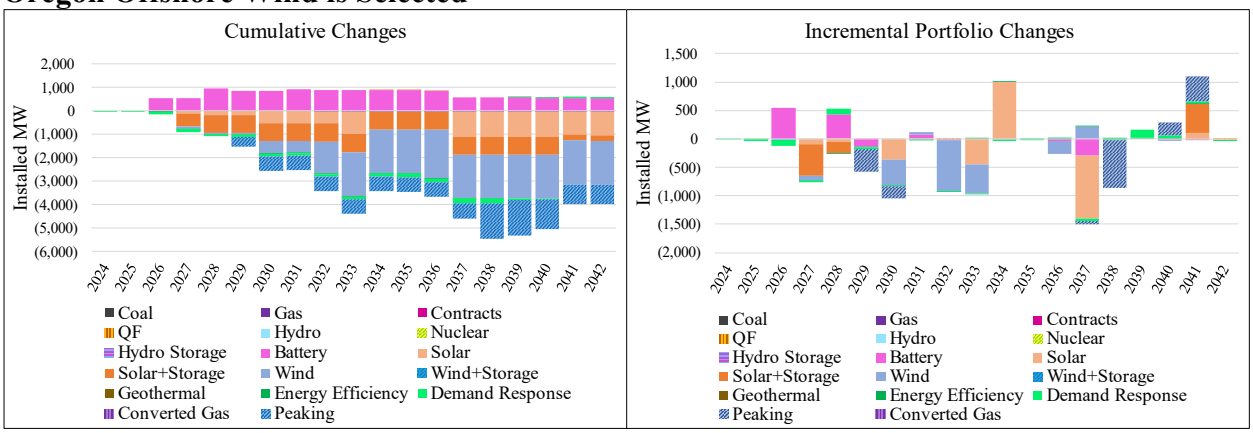
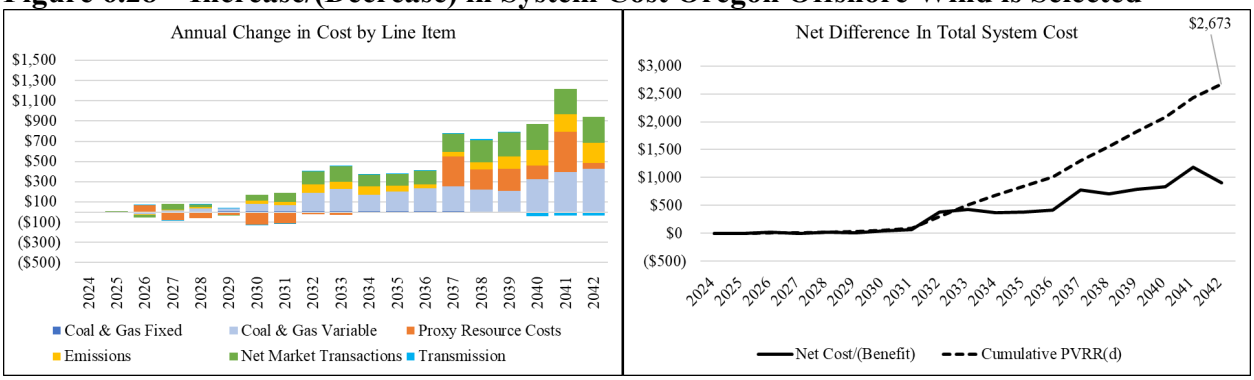


Figure 6.28 below shows the change in system cost with the Oregon offshore wind, resulting in a $2.67b dollar increase in the PVRR of the portfolio. Overall, the change is negligible until 2031, where the system relies more on coal and gas, and has an increase in emissions costs and market transaction costs. Additionally higher proxy resource costs play a role in the higher overall cost of the portfolio.

Figure 6.28 – Increase/(Decrease) in System Cost Oregon Offshore Wind is Selected



Oregon HB 2021 Variant (Oregon Policy Study)

Modeling the Oregon small scale renewable resource requirement and a target to meet Oregon emissions requirements results in large changes to the selected resource mixture. The below portfolio assumes the entire system shares in incremental resources required to meet Oregon compliance (with the exception of small scale renewables). Note that the preferred portfolio (against which the Oregon view is being compared) incorporates Oregon selections, so this comparison shows what would incrementally be added for the other five states within PacifiCorp's footprint under the Oregon view.

In 2029, the portfolio incorporating these requirements adds additional battery. Total wind selections are lower through 2033 but increase starting in 2034. Overall solar selections are lower through the entirety of the period. Total peaking selections are lower overall, with the largest single year difference in 2040.

Figure 6.29 – Increase/(Decrease) in Proxy Resources Assuming Oregon HB 2021 Requirements (Oregon Policy Study)

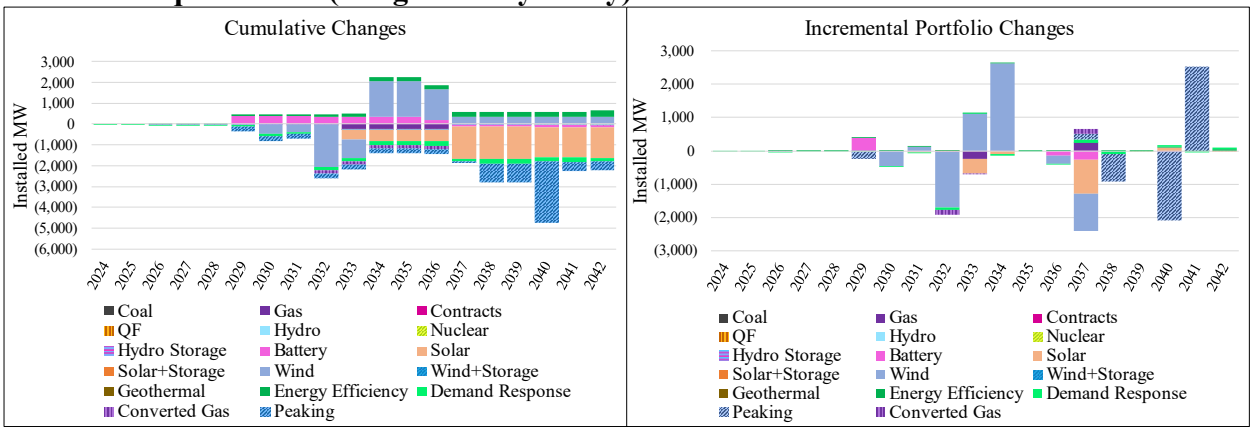
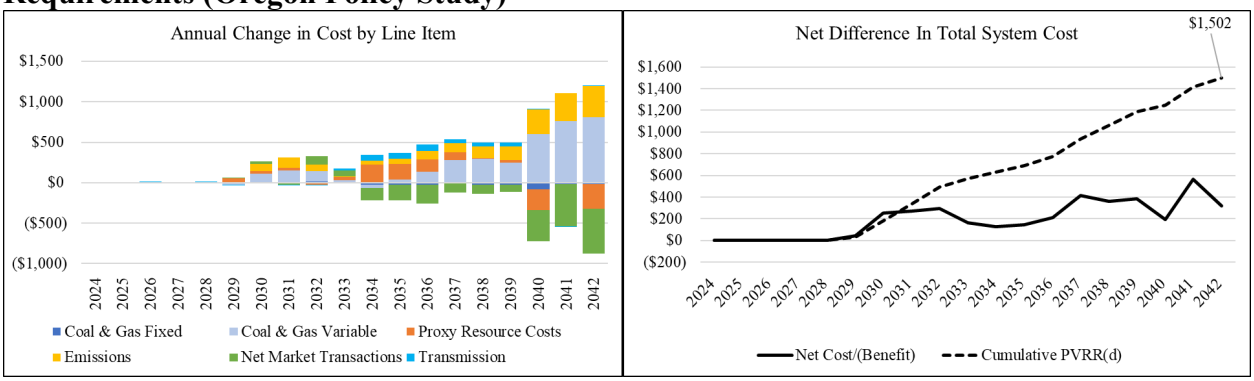


Figure 6.30 below shows the change in system cost when Oregon's requirements are embedded into the system run. The $1.5b PVRR difference is driven by higher proxy resource costs, as well as costs related to the operation of units that Oregon no longer participates in. Overall system level emissions are also higher due to a reliance on coal units in which Oregon no longer participates.

Figure 6.30 – Increase/(Decrease) in System Cost Assuming Oregon HB 2021 Requirements (Oregon Policy Study)



Washington SC CETA Variant (Washington Policy Study)

Modeling the Washington CETA requirements results in large changes to the selected resource mixture. The below portfolio assumes the entire system shares in incremental resources required to meet Washington compliance under SC-GHG. Note that the preferred portfolio (against which the Washington view is being compared) incorporates Washington situs selections, so this comparison shows what would incrementally be added for the other five states within PacifiCorp's footprint under the Washington view.

If the system were to take a larger share of Washington resources, additional wind and battery storage would make up the bulk of the change. The CETA run adds less peaking capacity starting in 2029, and more solar and battery in 2032. Incrementally more battery is added in 2036 and 2037, coupled with less peaking in the last five years of the study. Overall solar selections are approximately flat.

Figure 6.31 – Increase/(Decrease) in Proxy Resources Assuming Washington SC CETA Requirements (Washington Policy Study)

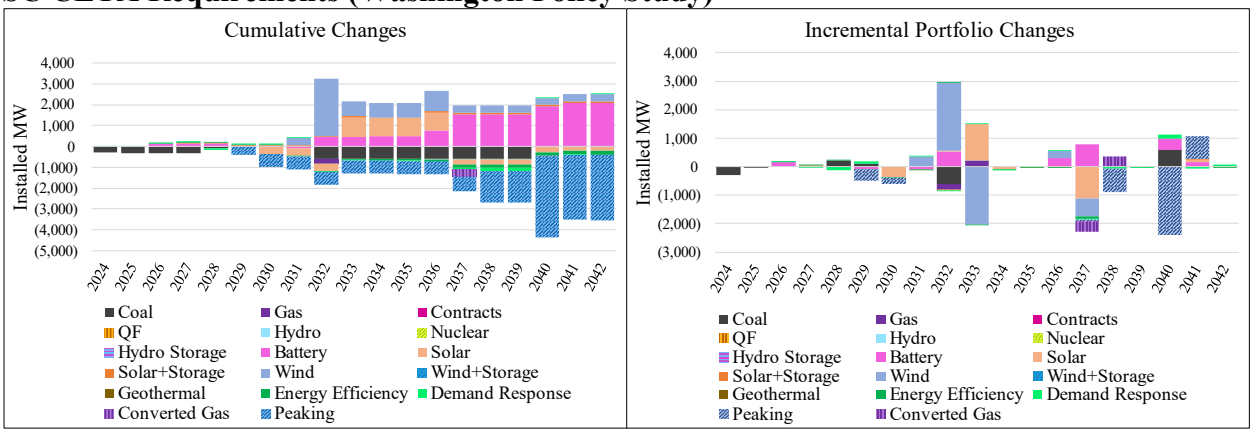
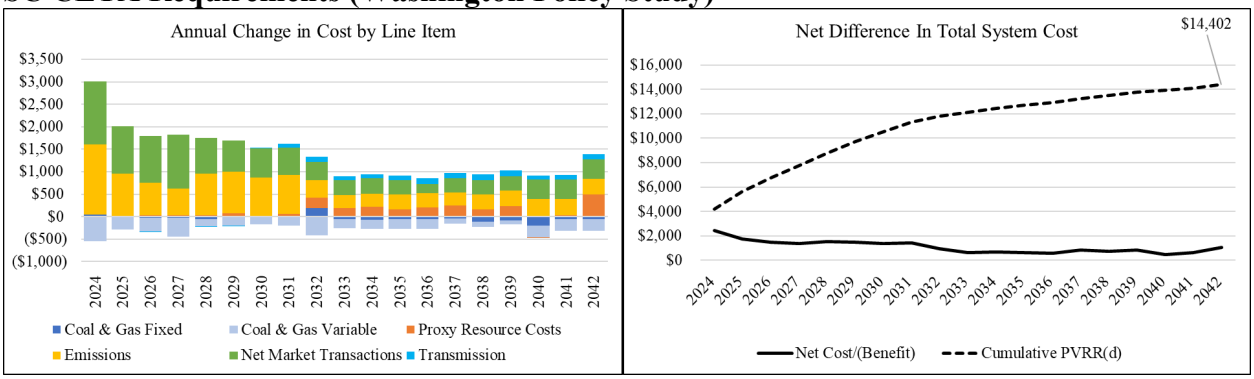


Figure 6.32 shows the change in system cost when the system as a whole is operated under the Washington CETA conditions. The $14.4b PVRR increase in cost is driven primarily by increased

emissions costs due to the SC-GHG emissions cost adder, as well as a significant overall net increase in market costs. Small reductions in coal and gas variable costs offset some of these expenses. Proxy resource costs are higher starting in 2029 and remain higher through the 20 year study period.

Figure 6.32 – Increase/(Decrease) in System Cost Assuming Washington SC CETA Requirements (Washington Policy Study)



PVRR Tables by Price-Policy Scenario

Table 6.7 – Cases Under MN

Period	Case Under MN	PVRR ($000)	Delta ($000)	OR 80% 2030	WA RPS	CCUS	Dispatch Price
20-YEAR	MN Base	$ 29,519	$ 748	N	N	Y	MN
20-YEAR	Preferred Portfolio	$ 28,823	$ 52	Y	Y	Y	MN
20-YEAR	Systemwide	**$ 28,771**	$ -	N	N	Y	MN
20-YEAR	No CCUS	$ 29,245	$ 474	Y	Y	N	MN
20-YEAR	No Nuclear	$ 29,252	$ 480	Y	Y	Y	MN
20-YEAR	Bridger 3 & 4 GC	$ 29,321	$ 550	Y	N	Y	MN

Table 6.8 – Cases Under MM

Period	Case Under MM	PVRR ($000)	Delta ($000)	OR 80% 2030	WA RPS	CCUS	Dispatch Price
20-YEAR	MM Base	$ 33,510	$ 703	N	N	Y	MM
20-YEAR	Preferred Portfolio	**$ 32,807**	$ -	Y	Y	Y	MM
20-YEAR	Systemwide	$ 32,912	$ 105	N	N	Y	MM
20-YEAR	No CCUS	$ 33,553	$ 746	Y	Y	N	MM
20-YEAR	No Nuclear	$ 33,464	$ 657	Y	Y	Y	MM
20-YEAR	Bridger 3 & 4 GC	$ 33,506	$ 700	Y	N	Y	MM

Table 6.9 – Cases Under SC-GHG

Period	Case Under SC-GHG	PVRR ($000)	Delta ($000)	OR 80% 2030	WA RPS	CCUS	Dispatch Price
20-YEAR	SC Base	$ 47,504	$ 350	N	N	Y	SC
20-YEAR	Preferred Portfolio	**$ 47,153**	$ -	Y	Y	Y	SC
20-YEAR	Systemwide	$ 47,730	$ 576	N	N	Y	SC
20-YEAR	No CCUS	$ 48,031	$ 877	Y	Y	N	SC
20-YEAR	No Nuclear	$ 48,493	$ 1,340	Y	Y	Y	SC
20-YEAR	Bridger 3 & 4 GC	$ 47,965	$ 812	Y	N	Y	SC

Table 6.10 – Cases Under LN

Period	Case Under LN	PVRR ($000)	Delta ($000)	OR 80% 2030	WA RPS	CCUS	Dispatch Price
20-YEAR	LN Base	$ 29,241	$ 1,447	N	N	Y	LN
20-YEAR	Preferred Portfolio	$ 28,042	$ 249	Y	Y	Y	LN
20-YEAR	Systemwide	**$ 27,794**	$ -	N	N	Y	LN
20-YEAR	No CCUS	$ 28,441	$ 647	Y	Y	N	LN
20-YEAR	No Nuclear	$ 28,212	$ 418	Y	Y	Y	LN
20-YEAR	Bridger 3 & 4 GC	$ 28,357	$ 563	Y	N	Y	LN

Table 6.11 – Cases Under HH

Period	Case Under HH	PVRR ($000)	Delta ($000)	OR 80% 2030	WA RPS	CCUS	Dispatch Price
20-YEAR	HH Base	**$ 41,622**	$ -	N	N	Y	HH
20-YEAR	Preferred Portfolio	$ 41,658	$ 36	Y	Y	Y	HH
20-YEAR	Systemwide	$ 42,252	$ 630	N	N	Y	HH
20-YEAR	No CCUS	$ 43,005	$ 1,384	Y	Y	N	HH
20-YEAR	No Nuclear	$ 43,047	$ 1,425	Y	Y	Y	HH
20-YEAR	Bridger 3 & 4 GC	$ 43,013	$ 1,392	Y	N	Y	HH

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CHAPTER 7 – ACTION PLAN STATUS UPDATE

This chapter provides an update on the action items listed in the Action Plan of PacifiCorp's 2023 Integrated Resource Plan (IRP). The status for all action items is provided in Table 7.1 below.

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Table 7.1 – 2023 IRP Action Plan Status Update

Action Item	1. Existing Resource Actions	Status
1a	**Colstrip Units 3 and 4:** • PacifiCorp pursues a beneficial change in ownership agreements that will enable an exit from the Colstrip project in Montana by 2030.	• PacifiCorp continues to work with co-owners to develop the most cost-effective path toward an exit from the project.
1b	**Craig Unit 1:** • PacifiCorp will continue to work closely with co-owners to seek the most cost-effective path forward toward the 2023 IRP Update preferred portfolio target exit date of December 31, 2025.	• PacifiCorp continues to work with co-owners to develop the most cost-effective path toward an exit from the project.
1c	**Naughton Units 1 and 2 Gas Conversion:** • PacifiCorp will initiate the process of converting Naughton Units 1 and 2 to natural gas beginning Q2 2023, including obtaining all required regulatory notices and filings. Natural gas operations are anticipated to commence spring of 2026. • PacifiCorp will initiate the closure of the Naughton South Ash Pond no later than the end of December 2025 when coal operations cease, and will complete closure by October 17, 2028, as required under its pond closure extension submission.	• PacifiCorp is on track to complete required regulatory notices and filings to process the conversion of Naughton Units 1 and 2 from coal to natural gas. • Coal supply agreements for Naughton Units 1 and 2 will not be extended beyond the end of December 2025.
1d	**Jim Bridger Units 1 and 2 Gas Conversion:** • PacifiCorp has initiated the process of ending coal-fueled operations. The Wyoming Air Quality Division issued an air permit on December 28, 2022, for the natural gas conversion. All required regulatory notices and filings will be completed by end of 2023.	• PacifiCorp received an approval order on December 7, 2023 from the Wyoming Public Service Commission for the conversion of Jim Bridger Units 1 and 2 from coal to natural gas. • PacifiCorp ceased coal-fueled operations at Jim Bridger Units 1 and 2 on December 31, 2023.

	• By the end of Q4 2023, PacifiCorp will administer termination, amendment, or close-out of existing permits, contracts, and other agreements.	• Removal of coal handling equipment and installation of natural gas components began on January 1, 2024. Conversions are on track for completion in Q2 2024.
1e	**Carbon Capture, Utilization, and Storage / Wyoming House Bill 200 Compliance:** • PacifiCorp will complete an evaluation of the information received as part of the CCUS RFP and RFI processes by the end of Q3 2023. • PacifiCorp will submit, for Wyoming Public Service Commission approval, a final plan in compliance with the low-carbon energy portfolio standard no later than March 31, 2024.	• PacifiCorp completed its evaluation of information received as part of the CCUS RFP and RFI process in August of 2023. • PacifiCorp filed its final plan with the Wyoming Public Service Commission on March 29, 2024, as required under Wyoming House Bill 200.
1f	**Regional Haze Compliance:** • Following the resolution of first planning period regional haze compliance disputes, and the EPA's determination of the states' second planning period regional haze state implementation plans, PacifiCorp will evaluate and model any emission control retrofits, emission limitations, or utilization reductions that are required for coal units. • PacifiCorp will continue to engage with the EPA, state agencies, and stakeholders to achieve second planning period regional haze compliance outcomes that improve Class I visibility, provide environmental benefits, and are cost effective.	• Utah's first planning period disputes have been resolved. • Naughton and Wyodak's first planning period disputes have been resolved. The Tenth Circuit found EPA's disapproval of Wyoming's plan for Wyodak unlawful and remanded the plan to EPA for further review in accordance with the requirements of the Clean Air Act. No proposed rule has been issued to date. • Wyoming submitted its state-approved revised regional haze plan requiring the natural gas conversion of Jim Bridger Units 1 and 2 to EPA for approval. EPA is reviewing the state plan. PacifiCorp continues to comply with the state-approved plan and operating permits. • PacifiCorp continues to engage with the EPA, state agencies, and stakeholders relating to second planning period regional haze compliance. No

		second planning period requirements have been finalized by EPA to date.
1g	**<u>Natrium™ Demonstration Project:</u>** • PacifiCorp will continue to monitor and report key TerraPower milestones for development and will make regulatory filings, as applicable. • By the end of 2023, PacifiCorp expects to finalize commercial agreements for the Natrium™ project. • By Q2 2024, PacifiCorp expects to develop a community action plan in coordination with community leaders. PacifiCorp will continue to monitor key TerraPower milestones for development and will make regulatory filings, as applicable, including, but not limited to, a request for the Oregon Public Utility Commission to explicitly acknowledge an alternative acquisition method consistent with OAR 860-089-0100(3)(c), and a request for a waiver of a solicitation for a significant energy resource decision consistent with Utah statute 54-17-501.	Unchanged
1h	**<u>Ozone Transport Rule Compliance:</u>** • PacifiCorp will assess the impact of EPA's finalized Ozone Transport Rule from March 2023, relative to the assumptions contained in the 2023 IRP. • PacifiCorp will continue to engage with the EPA, state agencies, and stakeholders to achieve Ozone Transport Rule compliance outcomes that provide environmental benefits, support reliable energy delivery and are cost effective. • Based on the Ozone Transport Rule trading program and the associated benefits for reducing NOx emissions, PacifiCorp will install selective non-	• EPA finalized its approval of Wyoming's cross-state ozone state plan on December 19, 2023. This approval means PacifiCorp facilities in Wyoming are not subject to the federal ozone plan requirements. • The Tenth Circuit granted a motion to stay EPA's disapproval of Utah's state ozone plan. Utah is not subject to federal ozone requirements while the stay is in place. The Utah ozone case was transferred to the D.C. Circuit in February of 2024, for adjudication of the merits, leaving the stay in place.

	catalytic reduction retrofit equipment at the following units by 2026: Huntington Units 1 and 2, Hunter Units 1-3, and Wyodak. The Company will initiate procurement and permitting activities beginning Q2 2023.	
Action Item	**2. New Resource Actions**	**Status**
2a	**<u>Customer Preference Request for Proposals:</u>** • PacifiCorp is continuously receiving and evaluating requests for voluntary customer programs in Utah and Oregon. PacifiCorp may use the marginal resources from ongoing 2022AS RFP and future request for proposals to fulfill customer need. In some cases, customer preference may necessitate issuance of a request for proposals to procure resources within the action plan window. • Consistent with Utah Community Renewable Energy Act, PacifiCorp continues to work with eligible communities to develop program to achieve goal of being net 100% renewable by 2030; PacifiCorp anticipates filing an application for approval of the program with the Utah Public Service Commission in 2024 or 2025, which may necessitate issuance of a request for proposals to procure resources within the action plan window.	• PacifiCorp and the eligible communities are meeting monthly to discuss program design. Subject to the finalization of the program details, PacifiCorp anticipates applying for approval of the program with the Utah Public Service Commission in 2024 or 2025.
2b	**<u>2024 All-Source Request for Proposals:</u>** • PacifiCorp will issue an all-source Request for Proposals (RFP) to procure resources aligned with the	• PacifiCorp does not have plans to issue an all-source Request for Proposals at this time but is continuously receiving and evaluating offers for resources to meet its requirements.

	2023 IRP preferred portfolio that can achieve commercial operations by the end of December 2028. • In Q4 2023, PacifiCorp will notify the Public Utility Commission of Oregon, the Public Service Commission of Utah, and the Washington Utilities and Transportation Commission, of PacifiCorp's need for an independent evaluator. • In Q1 2024, PacifiCorp will file a draft all-source RFP with applicable state utility commissions. • In Q3 2024, PacifiCorp expects to receive approval of the all-source RFP from applicable state utility commissions and issue the RFP to the market. • In Q4 2024, PacifiCorp will identify a final shortlist from the all-source RFP, and file for approval of the final shortlist in Oregon. Similarly, PacifiCorp will make a filing in Utah for significant energy resources on final shortlist. PacifiCorp will file a certificate of public convenience and necessity (CPCN) applications, as applicable. • By Q1 2025 PacifiCorp will execute definitive agreements with winning bids from the all-source RFP. • Winning bids from the all-source RFP are expected to achieve commercial operation by December 31, 2028, or earlier.	• Based on the resource procurement need identified in this IRP Update, it is likely that the 2025 IRP will include an action item to procure incremental resources to serve customers over the long term. Nonetheless, a new resource procurement action item will be established after development of the 2025 IRP.
2c	**<u>2022 All-Source Request for Proposals:</u>** • In April 2022 PacifiCorp issued an all-source Request for Proposals to procure resources that can achieve commercial operations by the end of December 2027.	• PacifiCorp suspended the 2022 All-Source RFP in September 2023 to further evaluate how key changes in the planning environment might influence long-term resource procurement activities.

	• In Q2 2023, PacifiCorp will identify a final shortlist from the all-source RFP, and file for approval of the final shortlist in Oregon. Similarly, PacifiCorp will make a filing in Utah for any applicable significant energy resources on final shortlist. PacifiCorp will file certificate of public convenience and necessity (CPCN) applications, as applicable, and • By Q4 2023 PacifiCorp will execute definitive agreements with winning bids from the all-source RFP. • Winning bids from the 2022 all-source RFP are expected to achieve commercial operation by December 31, 2027, or earlier.	• EPA's approval of Wyoming's cross-state ozone transport rule plan and the Tenth Circuit Court's stay of Utah's ozone plan have materially impacted the need for the type and volume of resources identified in the 2023 IRP preferred portfolio, which considered resource procurement needs coming out of the 2022 All-Source Request for Proposals. • Consequently, PacifiCorp is executing on a near-term resource procurement strategy that is consistent with the preferred portfolio in this IRP Update and will terminate the 2022 All Source Request for Proposals.
Action Item	3. **Transmission Action Items**	**Status**
3a	**<u>Energy Gateway South Segment F (Aeolus-Clover 500 kV transmission line):</u>** • In Q4 2024, construction of Energy Gateway South is expected to be completed and placed in service.	• Regulatory approval processes for certificates of public convenience and necessity in Utah and Wyoming are on track. In Utah an unopposed stipulation for the CPCN was filed February 22, 2022, and a commission order is pending. In Wyoming, hearings were completed March 2, 2022, and briefs due April 1, 2022; a decision is expected in early Q2 2022. Wyoming approval will be conditioned on obtaining all right-of-way, which is on track to be completed by the end of Q2 2022.

3b	**Energy Gateway West, Segment D.1 (Windstar-Shirley Basin 230 kV transmission line):** • In Q4 2024, construction of Energy Gateway West segment D.1 to be completed and placed in service. •	• PacifiCorp is finalizing construction of the Energy Gateway South and Energy Gateway West Sub-Segment D1 transmission projects.
3c	**Boardman-to-Hemingway (500 kV transmission line):** • Continue to support the project under the conditions of the Boardman-to-Hemingway Transmission Project (B2H) Joint Permit Funding Agreement. • Continue to participate in the development and negotiations of the construction agreement. • Continue to participate in "pre-construction" activities in support of the 2026-2027 in-service date. • Continue negotiations for plan of service post B2H for parties to the permitting agreement.	PacifiCorp has continued to participate in the support, negotiations, planning and permitting of the Boardman-to-Hemingway 500 kilovolt transmission line, which remains targeted for a 2026-2027 in-service date.
3d	Initiate Local Reinforcement Projects as identified with the addition of new resources per the preferred portfolio, and follow-on requests for proposal successful bids	Reinforcements have been identified. A final assessment of upgrades is pending signed agreements.
3e	Continue permitting support for Gateway West segments D.3 and E. Initiate preliminary permitting and development activities for future transmission investments not currently included in the preferred portfolio. These future transmission projects can include development of additional Energy Gateway segments and exploration of new routes that have connections to other regions (i.e., connecting southern Oregon to the east with connections to the desert southwest). These activities will enable	PacifiCorp continues permitting efforts on both segments D.3 and E, maintaining the record of decision on each segment.

	PacifiCorp to prepare for potential growth in new large loads seeking new service over the next decade.	

<table>
<tr><th>Action Item</th><th>4. Demand-Side Management (DSM) Actions</th><th>Status</th></tr>
<tr><td>4a</td><td>
<u>Energy Efficiency Targets:</u>

PacifiCorp will acquire cost-effective energy efficiency resources targeting annual system energy and capacity selections from the preferred portfolio as summarized below. PacifiCorp's state-specific processes for planning for DSM acquisitions is provided in Appendix D in Volume II of the 2023 IRP.
PacifiCorp will pursue cost-effective energy efficiency resources as summarized in the table below:

<table>
<tr><th>Year</th><th>1st Year Energy Efficiency (GWh)</th><th>Annual Capacity (MW)</th></tr>
<tr><td>2023</td><td>543</td><td>123</td></tr>
<tr><td>2024</td><td>559</td><td>220</td></tr>
<tr><td>2025</td><td>568</td><td>259</td></tr>
<tr><td>2026</td><td>628</td><td>197</td></tr>
</table>

PacifiCorp will pursue cost-effective demand response resources targeting annual system capacity[1] selections from the preferred portfolio[2] as summarized in the table below:

<table>
<tr><th>Year</th><th>Annual Incremental Capacity (MW)</th></tr>
<tr><td>2023</td><td>72</td></tr>
<tr><td>2024</td><td>39</td></tr>
<tr><td>2025</td><td>152</td></tr>
<tr><td>2026</td><td>109</td></tr>
</table>
[1] Capacity impacts for demand response include both summer and winter impacts within a year.
</td><td>

PacifiCorp achieved the Action Plan target of 543 GWh in 2023 and is on track to achieve its 2024 Class 2 DSM target.
PacifiCorp has launched a number of new demand response programs in 2022 and 2023. Additionally, the company is currently expanding its existing programs. PacifiCorp continues to pursue the incremental capacity additions but did not achieve the 2023 incremental capacity , due to the later than anticipated timing of program effective dates for newly launched demand response programs. However, the company anticipates achieving its cumulative capacity for 2024.

</td></tr>
</table>

	[2] A portion of cost-effective demand response resources identified in the 2023 preferred portfolio in 2023 for Oregon and Washington represent planned volumes expected are expected to be acquired through a previously issued demand response RFP soliciting resources identified in the 2019 IRP. PacifiCorp will pursue all cost-effective demand response resources identified as incremental to existing resources or as an expansion of existing resources offered through approved programs.	
Action Item	5. **Market Purchases**	**Status**
5a	**Market Purchases:** • Acquire short-term firm market purchases for on-peak delivery from 2023-2025 consistent with the Risk Management Policy and Energy Supply Management Front Office Procedures and Practices. These short-term firm market purchases will be acquired through multiple means: Balance of month and day-ahead brokered transactions in which the broker provides a competitive price. • Balance of month, day-ahead, and hour-ahead transactions executed through an exchange, such as the Intercontinental Exchange, in which the exchange provides a competitive price. • Prompt-month, balance-of-month, day-ahead, and hour-ahead non-brokered bi-lateral transactions.	• Since the publication of the 2023 IRP action plan, PacifiCorp has continued to transact consistent with its risk management and energy supply procedures to reliably cost-effectively serve customer requirements. Such transactions include seeking competitive pricing to acquire short-term firm purchases, execute balance of month, day-ahead and hour-ahead transactions through exchanges, and engage in prompt-month, balance-of-month, day-ahead and hour-ahead non-brokered bi-lateral transactions.

Action Item	6. **Renewable Energy Credit (REC) Actions**	**Status**
6a	**<u>Renewable Portfolio Standards (RPS):</u>** • PacifiCorp will pursue unbundled REC RFPs and purchases to meet its state RPS compliance requirements. • As needed, issue RFPs seeking unbundled RECs that will qualify in meeting California RPS targets through 2024 and future compliance periods as needed.	• PacifiCorp will continue to evaluate the need for unbundled RECs and issue RFPs to meet its state RPS compliance requirements as needed.
6b	**<u>Renewable Energy Credit Sales:</u>** • Maximize the sale of RECs that are not required to meet state RPS compliance obligations.	• PacifiCorp will continue to issue reverse RFPs to maximize the sale of RECs that are not required to meet state RPS compliance obligations

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APPENDIX A – ADDITIONAL LOAD FORECAST DETAILS

The load forecast presented in Chapter 4 represents the data used for capacity expansion modeling and excludes load reductions from incremental energy efficiency resources (Class 2 DSM). The load forecast used in the 2023 IRP Update was produced in May 2023. The average annual energy growth rate for the 2024 through 2042 timeframe is 2.13 percent. Relative to the load forecast prepared for the 2023 IRP, PacifiCorp's 2041 forecasted energy requirement decreased in all jurisdictions other than Utah. Table A.1 and Table A.2 illustrate the annual load and coincident peak load forecast when not reducing load projections to account for new energy efficiency measures (Class 2 DSM).[1]

Table A.1 – Forecasted Annual Load Growth, 2024 through 2042 (Megawatt-hours), at Generation, pre-DSM

Year	Total	OR	WA	CA	UT	WY	ID
2024	64,968,110	16,245,780	4,585,770	843,490	29,595,760	9,737,710	3,959,600
2025	67,342,930	17,306,840	4,594,200	838,350	30,789,780	9,840,730	3,973,030
2026	68,341,610	18,158,130	4,613,400	837,260	30,853,380	9,882,670	3,996,770
2027	71,581,930	19,426,800	4,629,410	836,940	32,713,240	9,955,510	4,020,030
2028	76,717,850	21,035,020	4,664,190	839,860	36,091,430	10,038,900	4,048,450
2029	78,931,210	22,407,980	4,681,190	838,600	36,875,730	10,065,380	4,062,330
2030	81,000,340	23,159,280	4,710,570	840,340	38,109,540	10,100,330	4,080,280
2031	83,090,030	24,287,060	4,737,420	841,830	38,958,030	10,168,810	4,096,880
2032	84,020,840	24,745,390	4,775,560	844,880	39,308,670	10,229,110	4,117,230
2033	84,868,040	24,957,970	4,792,040	843,400	39,868,630	10,280,680	4,125,320
2034	85,779,130	25,202,840	4,825,440	844,690	40,424,050	10,342,060	4,140,050
2035	86,764,370	25,492,360	4,863,490	846,560	40,999,620	10,406,500	4,155,840
2036	87,968,040	25,852,880	4,918,760	850,950	41,669,790	10,496,540	4,179,120
2037	88,920,970	26,150,610	4,952,290	850,940	42,234,980	10,541,160	4,190,990
2038	90,083,150	26,508,200	5,002,820	853,330	42,896,560	10,611,960	4,210,280
2039	91,291,270	26,881,290	5,055,910	855,790	43,580,400	10,686,960	4,230,920
2040	92,669,760	27,298,340	5,123,440	860,460	44,346,910	10,783,150	4,257,460
2041	93,733,980	27,630,780	5,163,010	860,290	44,980,320	10,829,300	4,270,280
2042	94,980,880	28,011,130	5,218,220	862,720	45,695,500	10,902,990	4,290,320
Compound Annual Growth Rate							
2024-33	**3.01%**	**4.89%**	**0.49%**	**0.00%**	**3.37%**	**0.60%**	**0.46%**
2024-42	**2.13%**	**3.07%**	**0.72%**	**0.13%**	**2.44%**	**0.63%**	**0.45%**

[1] Class 2 DSM load reductions are included as resources in the System Optimizer model.

Table A.2 - Forecasted Annual Coincident Peak Load (Megawatts) at Generation, pre-DSM

Year	Total	OR	WA	CA	UT	WY	ID
2024	11,200	2,645	832	146	5,578	1,240	759
2025	11,576	2,786	840	146	5,736	1,276	792
2026	11,629	2,868	846	148	5,742	1,233	791
2027	12,019	3,020	853	149	5,943	1,263	790
2028	12,528	3,137	860	149	6,362	1,245	774
2029	12,844	3,313	867	150	6,461	1,277	776
2030	13,077	3,403	873	150	6,612	1,260	778
2031	13,491	3,580	883	152	6,766	1,295	815
2032	13,522	3,647	899	156	6,742	1,254	824
2033	13,670	3,675	908	156	6,836	1,287	806
2034	13,807	3,707	918	157	6,924	1,294	807
2035	13,973	3,745	929	158	7,026	1,305	810
2036	14,212	3,791	940	159	7,128	1,315	879
2037	14,444	3,865	957	160	7,287	1,324	849
2038	14,618	3,910	968	161	7,399	1,330	851
2039	14,767	3,956	979	161	7,500	1,338	833
2040	14,930	3,998	989	162	7,598	1,351	833
2041	15,106	4,050	998	162	7,700	1,360	836
2042	15,437	4,202	1,017	165	7,814	1,371	870
Compound Annual Growth Rate							
2024-33	**2.24%**	**3.72%**	**0.98%**	**0.79%**	**2.29%**	**0.42%**	**0.68%**
2024-42	**1.80%**	**2.60%**	**1.12%**	**0.69%**	**1.89%**	**0.56%**	**0.76%**

Table A.3 and Table A.4 show the forecast changes relative to the 2023 IRP load forecast for loads and coincident system peak, respectively.

Table A.3 – Annual Load Growth Change: 2023 IRP Update Forecast less 2023 IRP Forecast (Megawatt-hours) at Generation, pre-DSM

Year	Total	OR	WA	CA	UT	WY	ID
2024	(2,531,160)	(2,128,670)	(106,340)	(18,070)	(144,270)	(25,850)	(107,960)
2025	(2,462,130)	(2,423,480)	(106,560)	(16,870)	428,560	(234,130)	(109,650)
2026	(1,596,810)	(2,299,520)	(108,360)	(15,710)	1,165,900	(230,570)	(108,550)
2027	(1,067,840)	(2,334,490)	(127,420)	(16,240)	1,678,820	(161,430)	(107,080)
2028	36,730	(2,410,940)	(147,010)	(16,620)	2,907,690	(190,210)	(106,180)
2029	1,011,930	(1,544,800)	(160,120)	(16,560)	3,014,370	(174,590)	(106,370)
2030	2,188,500	(906,780)	(174,780)	(15,450)	3,625,640	(232,220)	(107,910)
2031	2,709,340	(534,630)	(193,280)	(14,770)	3,758,140	(195,310)	(110,810)
2032	2,699,060	(415,490)	(214,840)	(15,080)	3,708,320	(247,620)	(116,230)
2033	2,645,810	(461,810)	(234,210)	(15,300)	3,706,680	(227,590)	(121,960)
2034	2,427,590	(538,750)	(251,540)	(15,430)	3,578,720	(217,420)	(127,990)
2035	2,214,410	(592,800)	(265,300)	(15,330)	3,424,820	(203,540)	(133,440)
2036	1,983,190	(645,890)	(278,160)	(13,920)	3,251,390	(189,950)	(140,280)
2037	1,741,220	(697,660)	(289,600)	(12,540)	3,066,420	(177,980)	(147,420)
2038	1,497,900	(749,210)	(300,050)	(11,340)	2,877,410	(163,610)	(155,300)
2039	1,264,110	(796,550)	(309,440)	(10,240)	2,690,480	(146,310)	(163,830)
2040	1,025,650	(846,980)	(316,480)	(9,310)	2,501,260	(130,110)	(172,730)
2041	737,420	(918,850)	(321,730)	(8,500)	2,283,370	(115,200)	(181,670)
2042	389,750	(1,007,770)	(326,570)	(7,830)	2,019,850	(97,090)	(190,840)

Table A.4 – Annual Coincident Peak Growth Change: 2023 IRP Update Forecast less 2023 IRP Forecast (Megawatts) at Generation, pre-DSM

Year	Total	OR	WA	CA	UT	WY	ID
2024	(228)	(188)	(14)	(1)	41	(55)	(11)
2025	(171)	(225)	(16)	(1)	108	(25)	(11)
2026	(129)	(186)	(24)	0	170	(72)	(17)
2027	(32)	(168)	(34)	(1)	237	(43)	(23)
2028	43	(186)	(45)	(2)	369	(73)	(20)
2029	161	(174)	(60)	(7)	438	(15)	(22)
2030	261	(104)	(72)	(8)	511	(42)	(24)
2031	369	(50)	(83)	(8)	552	(16)	(26)
2032	313	15	(86)	(5)	473	(61)	(23)
2033	323	5	(98)	(6)	480	(35)	(24)
2034	295	(4)	(109)	(6)	476	(36)	(27)
2035	281	(9)	(115)	(6)	476	(34)	(30)
2036	258	(10)	(125)	(7)	474	(33)	(42)
2037	326	10	(127)	(6)	519	(31)	(39)
2038	318	4	(131)	(6)	523	(31)	(41)
2039	304	(2)	(134)	(7)	515	(30)	(38)
2040	259	(22)	(141)	(8)	498	(28)	(40)
2041	225	(28)	(151)	(9)	482	(27)	(43)
2042	250	16	(150)	(8)	465	(25)	(49)

This section provides total system and state-level forecasted retail sales summaries measured at the customer meter by customer class including load reduction projections from new energy efficiency measures from the 2023 IRP Update preferred portfolio. The average annual retail sales growth rate for the 2024 through 2042 time period is 1.23 percent.

Table A.5 – System Annual Retail Sales Forecast 2024 through 2042 (Megawatt-hours), post-DSM

System Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2024	17,835,359	22,022,137	18,129,854	1,464,602	101,588	59,553,539
2025	17,942,494	23,278,978	18,467,591	1,459,535	98,916	61,247,513
2026	18,069,292	24,757,523	17,208,712	1,457,137	97,095	61,589,760
2027	18,206,269	27,097,919	17,256,311	1,455,278	95,610	64,111,386
2028	18,404,095	31,140,919	17,280,459	1,454,743	94,532	68,374,747
2029	18,477,357	32,446,403	17,226,100	1,454,103	92,916	69,696,878
2030	18,606,777	33,539,212	17,210,097	1,453,570	91,552	70,901,208
2031	18,675,809	34,617,478	17,240,040	1,452,530	90,221	72,076,078
2032	18,820,591	34,586,724	17,254,846	1,450,538	89,285	72,201,984
2033	18,835,115	34,621,087	17,256,601	1,447,587	88,046	72,248,436
2034	18,996,580	34,605,852	17,235,396	1,445,981	87,309	72,371,118
2035	19,150,780	34,635,808	17,258,048	1,446,071	86,790	72,577,498
2036	19,538,961	34,643,086	17,290,488	1,445,336	86,694	73,004,564
2037	19,799,830	34,611,441	17,243,053	1,441,270	86,217	73,181,811
2038	20,105,118	34,651,180	17,352,250	1,440,699	86,074	73,635,320
2039	20,614,193	34,653,725	17,378,585	1,441,351	85,984	74,173,839
2040	21,076,584	34,765,209	17,459,911	1,440,498	86,178	74,828,378
2041	21,548,567	34,680,463	17,469,255	1,437,205	85,894	75,221,384
2042	22,232,471	34,699,960	17,363,944	1,435,197	85,872	75,817,444
Compound Annual Growth Rate						
2024-33	**0.61%**	**5.16%**	**-0.55%**	**-0.13%**	**-1.58%**	**2.17%**
2024-42	**1.23%**	**2.56%**	**-0.24%**	**-0.11%**	**-0.93%**	**1.35%**

Table A.6– Forecasted Retail Sales Growth in Oregon, post-DSM

Oregon Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2024	6,009,691	6,770,640	1,423,019	254,060	30,978	14,488,387
2025	6,001,793	7,550,785	1,453,780	254,046	30,286	15,290,690
2026	5,995,405	8,177,475	1,460,958	254,434	29,787	15,918,058
2027	6,003,026	9,161,375	1,473,922	254,806	29,402	16,922,531
2028	6,040,301	10,444,341	1,471,106	255,295	29,196	18,240,240
2029	6,049,448	11,550,309	1,457,111	255,521	28,897	19,341,286
2030	6,090,809	12,048,507	1,458,396	255,858	28,741	19,882,311
2031	6,127,520	12,883,018	1,465,861	256,183	28,628	20,761,210
2032	6,199,100	13,093,944	1,479,500	256,629	28,630	21,057,804
2033	6,237,207	13,137,551	1,466,220	256,811	28,489	21,126,278
2034	6,338,859	13,139,320	1,468,115	257,125	28,448	21,231,867
2035	6,468,636	13,149,739	1,479,593	257,436	28,419	21,383,824
2036	6,669,733	13,154,447	1,502,446	257,906	28,481	21,613,013
2037	6,811,623	13,159,336	1,512,959	258,098	28,384	21,770,399
2038	7,025,020	13,161,006	1,537,519	258,427	28,373	22,010,346
2039	7,234,260	13,182,394	1,561,310	258,757	28,366	22,265,087
2040	7,472,789	13,213,778	1,582,701	259,234	28,443	22,556,946
2041	7,673,642	13,233,651	1,581,848	259,423	28,357	22,776,921
2042	7,903,205	13,247,462	1,596,956	259,761	28,355	23,035,739
Compound Annual Growth Rate						
2024-33	**0.41%**	**7.64%**	**0.33%**	**0.12%**	**-0.93%**	**4.28%**
2024-42	**1.53%**	**3.80%**	**0.64%**	**0.12%**	**-0.49%**	**2.61%**

Table A.7 – Forecasted Retail Sales Growth in Washington, post-DSM

Washington Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2024	1,601,673	1,506,545	804,037	157,390	3,954	**4,073,599**
2025	1,596,063	1,487,833	790,828	156,906	3,946	**4,035,576**
2026	1,606,514	1,478,251	779,113	155,415	3,946	**4,023,239**
2027	1,599,312	1,472,524	772,203	155,946	3,946	**4,003,931**
2028	1,597,287	1,471,963	767,628	156,535	3,958	**3,997,372**
2029	1,583,980	1,461,843	763,578	157,015	3,946	**3,970,362**
2030	1,574,662	1,455,718	760,964	157,382	3,946	**3,952,672**
2031	1,560,284	1,449,623	758,497	157,457	3,946	**3,929,807**
2032	1,549,350	1,448,952	758,110	157,384	3,958	**3,917,753**
2033	1,531,635	1,441,254	753,176	157,196	3,946	**3,887,207**
2034	1,523,973	1,441,061	749,436	157,086	3,946	**3,875,501**
2035	1,520,091	1,442,724	748,469	157,033	3,946	**3,872,264**
2036	1,528,896	1,447,477	749,604	157,047	3,958	**3,886,982**
2037	1,529,356	1,447,673	746,146	156,771	3,946	**3,883,892**
2038	1,537,274	1,455,963	747,027	156,579	3,946	**3,900,789**
2039	1,551,443	1,464,098	746,962	157,040	3,946	**3,923,488**
2040	1,569,387	1,481,238	749,544	157,329	3,958	**3,961,454**
2041	1,581,156	1,481,808	748,556	157,439	3,946	**3,972,906**
2042	1,606,537	1,491,652	742,156	157,315	3,946	**4,001,605**
Compound Annual Growth Rate						
2024-33	**-0.50%**	**-0.49%**	**-0.72%**	**-0.01%**	**-0.02%**	**-0.52%**
2024-42	**0.02%**	**-0.06%**	**-0.44%**	**0.00%**	**-0.01%**	**-0.10%**

Table A.8 – Forecasted Retail Sales Growth in California, post-DSM

California Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2024	376,345	232,906	54,770	95,410	1,658	**761,090**
2025	374,646	228,918	53,970	94,253	1,631	**753,419**
2026	373,722	226,296	53,643	93,333	1,615	**748,609**
2027	372,691	224,347	53,351	92,412	1,602	**744,404**
2028	372,904	223,476	53,080	91,544	1,598	**742,601**
2029	370,484	221,334	52,568	90,463	1,587	**736,436**
2030	369,901	220,209	52,241	89,368	1,582	**733,302**
2031	368,511	218,594	51,858	87,885	1,578	**728,426**
2032	368,024	218,000	51,707	86,030	1,580	**725,341**
2033	365,118	216,085	51,301	84,033	1,574	**718,111**
2034	363,645	214,991	51,113	82,425	1,573	**713,747**
2035	362,994	214,268	50,975	81,232	1,572	**711,041**
2036	363,704	213,426	51,090	80,048	1,576	**709,843**
2037	361,226	211,507	50,815	78,668	1,571	**703,787**
2038	360,660	211,315	50,682	77,270	1,570	**701,498**
2039	361,102	210,364	50,669	76,011	1,570	**699,715**
2040	362,086	211,499	50,618	74,631	1,575	**700,409**
2041	360,656	210,852	50,306	73,201	1,570	**696,584**
2042	362,167	210,457	50,226	71,747	1,570	**696,167**
Compound Annual Growth Rate						
2024-33	**-0.34%**	**-0.83%**	**-0.72%**	**-1.40%**	**-0.57%**	**-0.64%**
2024-42	**-0.21%**	**-0.56%**	**-0.48%**	**-1.57%**	**-0.30%**	**-0.49%**

Table A.9 – Forecasted Retail Sales Growth in Utah, post-DSM

Utah Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2024	8,044,158	11,601,120	7,584,303	241,504	50,329	**27,521,414**
2025	8,184,798	12,108,572	7,824,271	239,686	48,642	**28,405,969**
2026	8,322,690	12,993,901	6,552,088	238,852	47,672	**28,155,204**
2027	8,475,372	14,374,976	6,557,172	237,330	47,081	**29,691,932**
2028	8,648,984	17,143,145	6,562,389	235,938	46,862	**32,637,319**
2029	8,760,307	17,382,865	6,528,435	234,780	46,522	**32,952,910**
2030	8,884,515	18,004,112	6,522,459	233,524	46,402	**33,691,012**
2031	8,968,745	18,277,853	6,517,340	232,059	46,332	**34,042,329**
2032	9,078,372	18,046,433	6,517,560	230,470	46,423	**33,919,259**
2033	9,119,563	18,080,729	6,511,359	228,901	46,268	**33,986,820**
2034	9,212,741	18,071,133	6,494,788	227,711	46,254	**34,052,628**
2035	9,267,597	18,100,907	6,494,316	226,988	46,246	**34,136,055**
2036	9,450,409	18,101,571	6,484,776	225,810	46,373	**34,308,939**
2037	9,590,337	18,070,692	6,443,531	223,793	46,239	**34,374,592**
2038	9,685,086	18,113,815	6,504,625	222,814	46,238	**34,572,578**
2039	9,966,370	18,095,113	6,492,886	222,240	46,237	**34,822,845**
2040	10,170,049	18,158,012	6,515,025	221,329	46,368	**35,110,783**
2041	10,426,605	18,074,355	6,525,459	219,823	46,236	**35,292,478**
2042	10,787,650	18,042,629	6,487,029	218,242	46,236	**35,581,787**
Compound Annual Growth Rate						
2024-33	**1.40%**	**5.05%**	**-1.68%**	**-0.59%**	**-0.93%**	**2.37%**
2024-42	**1.64%**	**2.48%**	**-0.86%**	**-0.56%**	**-0.47%**	**1.44%**

Table A.10 – Forecasted Retail Sales Growth in Idaho, post-DSM

Idaho Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2024	784,413	545,807	1,689,601	685,232	2,691	**3,707,744**
2025	784,366	544,739	1,688,371	683,719	2,647	**3,703,842**
2026	784,715	544,373	1,688,312	684,273	2,593	**3,704,265**
2027	783,715	543,797	1,687,767	684,004	2,511	**3,701,794**
2028	782,571	545,468	1,686,184	684,592	2,403	**3,701,218**
2029	771,773	541,994	1,683,225	685,465	2,246	**3,684,702**
2030	762,271	538,681	1,682,323	686,442	2,068	**3,671,784**
2031	749,873	536,634	1,679,416	687,886	1,880	**3,655,688**
2032	738,061	535,740	1,678,499	688,862	1,709	**3,642,871**
2033	720,199	531,401	1,676,103	689,461	1,557	**3,618,721**
2034	706,735	530,090	1,673,407	690,352	1,445	**3,602,029**
2035	692,578	529,337	1,671,811	692,055	1,366	**3,587,147**
2036	685,158	529,991	1,670,468	693,131	1,317	**3,580,066**
2037	672,116	530,845	1,666,797	692,626	1,279	**3,563,662**
2038	657,883	534,191	1,668,270	694,303	1,257	**3,555,904**
2039	653,451	534,107	1,667,508	695,752	1,244	**3,552,061**
2040	648,666	539,676	1,667,303	697,053	1,239	**3,553,937**
2041	643,490	535,618	1,666,775	696,478	1,231	**3,543,592**
2042	646,050	537,030	1,661,863	696,748	1,228	**3,542,917**
Compound Annual Growth Rate						
2024-33	**-0.94%**	**-0.30%**	**-0.09%**	**0.07%**	**-5.90%**	**-0.27%**
2024-42	**-1.07%**	**-0.09%**	**-0.09%**	**0.09%**	**-4.27%**	**-0.25%**

Table A.11 – Forecasted Retail Sales Growth in Wyoming, post-DSM

Wyoming Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2024	1,019,079	1,365,118	6,574,122	31,006	11,978	**9,001,304**
2025	1,000,829	1,358,131	6,656,371	30,925	11,762	**9,058,017**
2026	986,246	1,337,228	6,674,597	30,831	11,483	**9,040,385**
2027	972,153	1,320,899	6,711,894	30,780	11,067	**9,046,794**
2028	962,048	1,312,525	6,740,071	30,839	10,514	**9,055,997**
2029	941,364	1,288,059	6,741,183	30,858	9,718	**9,011,183**
2030	924,619	1,271,986	6,733,713	30,996	8,813	**8,970,127**
2031	900,877	1,251,755	6,767,067	31,060	7,857	**8,958,617**
2032	887,682	1,243,655	6,769,470	31,164	6,985	**8,938,956**
2033	861,392	1,214,067	6,798,442	31,185	6,213	**8,911,299**
2034	850,627	1,209,257	6,798,538	31,282	5,643	**8,895,346**
2035	838,884	1,198,832	6,812,883	31,326	5,241	**8,887,167**
2036	841,061	1,196,174	6,832,104	31,394	4,989	**8,905,721**
2037	835,172	1,191,388	6,822,804	31,315	4,799	**8,885,478**
2038	839,195	1,174,889	6,844,128	31,305	4,689	**8,894,206**
2039	847,568	1,167,650	6,859,250	31,552	4,621	**8,910,642**
2040	853,608	1,161,005	6,894,719	30,922	4,595	**8,944,848**
2041	863,018	1,144,179	6,896,311	30,841	4,554	**8,938,903**
2042	926,862	1,170,731	6,825,714	31,383	4,538	**8,959,228**
Compound Annual Growth Rate						
2024-33	**-1.85%**	**-1.29%**	**0.37%**	**0.06%**	**-7.03%**	**-0.11%**
2024-42	**-0.53%**	**-0.85%**	**0.21%**	**0.07%**	**-5.25%**	**-0.03%**

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	)	Order No. 202-26-21

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed April 28, 2026

Exhibit 2-99:
PacifiCorp 2025 IRP

2025
Integrated Resource Plan

Volume I - March 31, 2025

PacifiCorp

This 2025 Integrated Resource Plan is based upon the best available information at the time of preparation. The IRP action plan will be implemented as described herein, but is subject to change as new information becomes available or as circumstances change. It is PacifiCorp's intention to revisit and refresh the IRP action plan no less frequently than annually. Any refreshed IRP action plan will be submitted to the State Commissions for their information.

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CHAPTER 1 – EXECUTIVE SUMMARY

Maintaining customer focus

Our 2025 Integrated Resource Plan (IRP) is a roadmap for continual progress in safely, reliably and affordably serving over 2 million customers across six states. This roadmap continues to deliver on PacifiCorp's commitments to the diverse communities in which it operates.

Roadmap

Two significant transmission projects have been placed in-service since the 2023 IRP, and are therefore included in the 2025 IRP as given accomplishments:

- The Energy Gateway South transmission line—a new 416-mile, high-voltage 500-kilovolt (kV) transmission line and associated infrastructure running from the Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah. This transmission line was placed in service in the fourth quarter of 2024.

- The Energy Gateway West Subsegment D1 project—a new high-voltage 230-kV transmission line and a rebuild of an existing 230 kV transmission line from the Shirley Basin substation in southeastern Wyoming to the Windstar substation near Glenrock, Wyoming. These lines were placed in service in fourth quarter of 2024.

These projects laid the groundwork for long-term affordability and reliability and helping build a more resilient grid.

New Resources

- The following resources are added in the 2025 IRP:
  - 3,782 megawatts of new wind resources
  - 7,524 megawatts of storage resources, including four-hour, and 100-hour durations
  - 5,912 megawatts of new solar resources, including utility-scale and small-scale
  - 500 megawatts of advanced nuclear (Natrium™ reactor demonstration project)

Customer Programs

- 5,255 megawatts of capacity saved through energy efficiency programs
- 769 megawatts of capacity saved through direct load control programs

Transmission

- Various upgrades to increase the transfer capability from southern Utah to the major load center in the Wasatch Front
- New transmission from the Walla Walla substation near Walla Walla, Washington to the Yakima substation near Yakima, Washington
- Various upgrades that increase transfer capability between the Summer Lake substation in Oregon and the Hemingway substation in Idaho

- New transmission, including a 110-mile line from Summer Lake to Burns, Oregon, and an 88-mile line from Summer Lake to the planned Full Circle substation in Central Oregon. These near-term upgrades connect with a later upgrade a new transmission line connecting Walla Walla to the Full Circle substation, expected in 2039.
- Additional local transmission upgrades to connect clean resources to the transmission system in southern Utah, southern and central Oregon, the Willamette Valley in Oregon, and in Yakima and Walla Walla, Washington

Key Thermal Outcomes

- Continue to work with co-owners to develop the most cost-effective path toward an exit from the Colstrip project in Montana by 2030
- Continue to evaluate carbon capture and sequestration options for Jim Bridger Units 3 and 4 in Rock Springs, Wyoming, for completion by 2030 to comply with Wyoming's low carbon portfolio standard
- Continue the process of coal-to-gas conversion of Naughton Units 1 and 2 in Kemmerer, Wyoming, for completion by 2026
- Initiate the process of coal-to-gas conversion of Dave Johnston Units 1 and 2 in Glenrock, Wyoming, for completion by 2029

PacifiCorp's Integrated Resource Plan Approach

In the 2025 IRP, PacifiCorp presents a preferred portfolio that builds on its vision to deliver energy affordably, reliably and responsibly through near-term investments in transmission infrastructure that will facilitate continued growth in new renewable resource capacity while maintaining substantial investment in energy efficiency and demand response programs.

At the same time, the preferred portfolio is responsive to the rapidly expanding arena of new state and federal regulatory requirements.

The 2025 IRP preferred portfolio demonstrates that reliable service will require investment in transmission infrastructure, new wind and solar resources, the conversion of four coal units to natural gas peaking units, significant demand response and energy efficiency programs, the addition of carbon capture technology on identified coal resources, the addition of an advanced nuclear resource, and the addition of energy storage resources. As discussed in Chapter 8, the 2025 IRP preferred portfolio includes resources necessary for individual state policy compliance and assumes those resources are situs-allocated and deliverable to the state whose policy necessitated the addition.

The primary objective of the IRP is to identify the best mix of proxy resources to serve customers in the future.[1] Building upon developments initiated in the 2023 IRP Update, PacifiCorp recognizes that the basis for identifying a least-cost, least-risk portfolio varies across its jurisdictions, so the 2025 IRP assesses the cost-effectiveness of individual resources in light of the requirements specific to each jurisdiction. For the 2025 IRP, three distinct sets of jurisdictional requirements were represented:

- Utah, Idaho, Wyoming, and California (UIWC)[2]
  - Cost-effective resources
  - Includes WRAP compliance constraints for UIWC load
- Oregon
  - Compliance with energy and emissions requirements from House Bill 2021 (HB2021)
  - Includes WRAP compliance constraints for Oregon load
  - Includes small-scale renewable capacity requirement
- Washington
  - Compliance with clean energy requirements from the Clean Energy Transformation Act (CETA)
  - Includes WRAP compliance constraints for Washington load

Resources identified under each jurisdictional view are brought together into an "integrated" portfolio and assumed to be situs to those jurisdictions in which they were identified as cost effective. For each jurisdiction, the best combination of resources is determined through analysis that measures cost and risk. Beyond the costs and risks quantified through modeling, the least-cost, least-risk resource portfolio is the portfolio that can be delivered through specific action items at a reasonable cost and with manageable risks while considering customer demand for clean energy and ensuring compliance with state and federal regulatory obligations.

The full planning process is completed every two years, with a review and update completed in the off years. Consequently, these plans, particularly their longer-range elements, can and do change over time.

PacifiCorp's 2025 IRP was developed through an open and extensive public process, with input from an active and diverse group of stakeholders, including customer advocacy groups, community members, regulatory staff, and other interested parties. The public input process began with the first public input meeting in January 2024, representing the earliest IRP cycle kick-off for PacifiCorp.

For the first time, in the 2025 IRP process PacifiCorp developed a full draft document and distributed it to stakeholders on December 31, 2024. The timing and requirements of this draft necessitated that coverage of IRP topics in the public input meeting series occur three months earlier than in past planning cycles, reducing the number of public meetings, but also increasing meeting length and accelerating the timing of the coverage of all topics. Following the kick-off,

[1] Proxy resources are not actual projects but indicative projects, with estimated costs, technology, timing and location. Actual project data is evaluated in downstream processes. One key example of such a downstream process is a request for proposals, in which bids are solicited on real-world projects where the costs, technology, timing and location can be known and are subject to negotiation.

[2] While California has a number of policy requirements, PacifiCorp is currently required to demonstrate compliance using system-wide portfolio results.

PacifiCorp hosted stakeholders in nine online public input meetings. Throughout this effort, PacifiCorp received valuable input from stakeholders and presented findings from a broad range of studies and technical analyses that shaped and informed the 2025 IRP. In the 2025 IRP, PacifiCorp also enhanced the connections between stakeholder input and IRP development by providing footnotes which reference stakeholder feedback the company received over the course of this IRP cycle. Links to each publicly available stakeholder feedback form and PacifiCorp response are provided in these footnotes and are provided in Appendix M (Stakeholder Feedback Forms).

As depicted in Figure 1.1, PacifiCorp's 2025 IRP was developed by working through five fundamental planning steps that began with development of key inputs and assumptions to inform the modeling and portfolio development process. The portfolio development process is where PacifiCorp produced a range of different resource portfolios that meet projected gaps in the load and resource balance, each uniquely characterized by the size, type, timing and location of new resources in PacifiCorp's system. The resource portfolios produced for the 2025 IRP were created considering a wide range of potential coal and natural gas retirement dates, options for certain coal units to convert to gas or to retrofit for carbon capture sequestration, and other planning uncertainties.

PacifiCorp then developed variants of the top performing resource portfolio to further analyze impacts of specific resource actions relative to the top performing portfolio. In the resource portfolio analysis step, PacifiCorp conducted targeted reliability analysis to ensure portfolios had sufficient flexible capacity resources to meet reliability requirements. PacifiCorp then analyzed these different resource portfolios to measure comparative cost, risk, reliability and emissions levels. This resource portfolio analysis informed selection of the least-cost and least-risk portfolio, the 2025 IRP preferred portfolio, and development of the associated near-term resource action plan. Throughout this process, PacifiCorp considered a wide range of factors to develop key planning assumptions and to identify key planning uncertainties, with input from its stakeholder group. Supplemental studies were also analyzed to produce specific modeling assumptions.

Figure 1.1 – Key Elements of PacifiCorp's 2025 IRP Approach

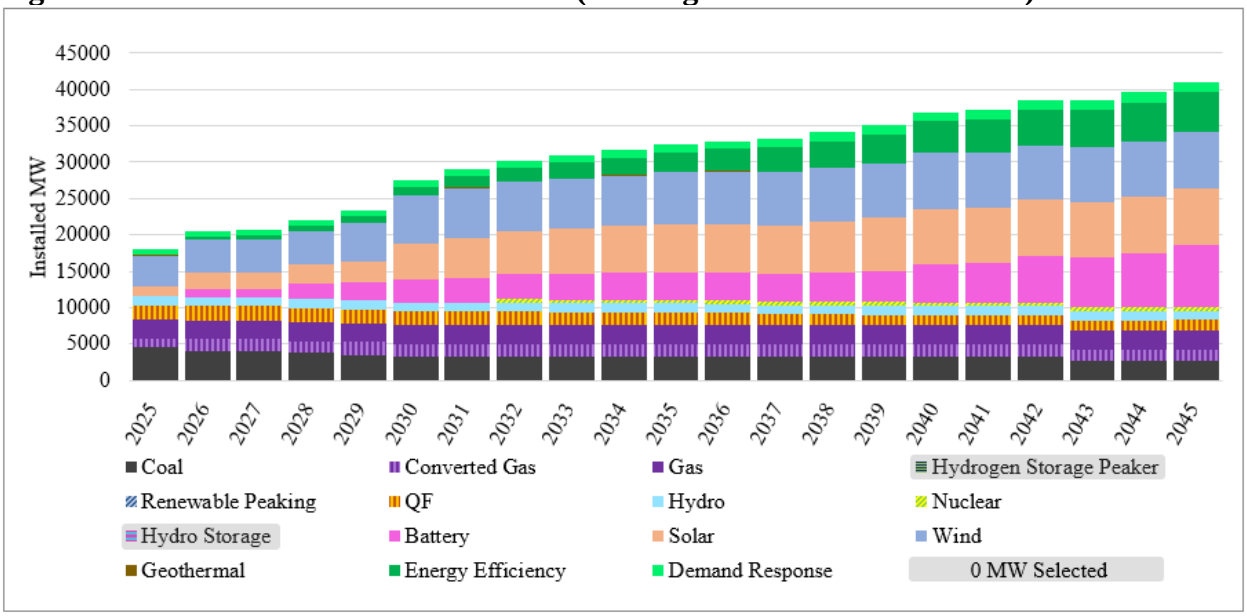
Preferred Portfolio Highlights

PacifiCorp's selection of the 2025 IRP preferred portfolio is supported by comprehensive data analysis and an extensive public input process, described in the chapters that follow. Figure 1.2 shows that PacifiCorp's 2025 preferred portfolio continues to include substantial new renewables, demand-side management (DSM) resources, storage resources, advanced nuclear, and renewable peaking resources facilitated by incremental transmission investments.

The 2025 IRP preferred portfolio is in addition to previously contracted resources, some of which have not yet achieved commercial operation, including: 1,564 megawatts (MW) of wind, 1,736 MW of solar additions, and 1,072 MW of battery storage capacity. These resources will come online in the 2025 to 2026 timeframe.

The 2025 IRP preferred portfolio includes the advanced nuclear Natrium™ demonstration project, anticipated to achieve online status by the fall of 2031. By the end of 2032, the preferred portfolio includes 2,408 MW of energy storage resources, including 605 MW of iron-air batteries with 100-hour storage capability. Advancement of these technologies will be critical to meeting growing loads and achieving environmental compliance requirements. Over the 21-year planning horizon, the 2025 IRP preferred portfolio includes 3,782 MW of new wind and 5,912MW of new solar.

Figure 1.2 – 2025 IRP Preferred Portfolio (Existing and Planned Resources)*



* Technologies highlighted in gray were available for selection in IRP modeling but are not part of PacifiCorp's existing resource mix and were not selected for the preferred portfolio.

The 2025 IRP preferred portfolio includes several transmission upgrades which increase transfer capability between southern Utah and the Wasatch Front and between Walla Walla and Yakima in Washington, as well as a series of upgrades that increase transfer capability between the Hemingway substation in Idaho, the Summer Lake Substation in southern Oregon, the planned Full Circle substation in Deschutes County, Oregon, and eventually connecting from Full Circle to Walla Walla in Washington. Many of the transmission upgrades and interconnection options modeled for the 2025 IRP reflect the results of PacifiCorp's "cluster study" process for evaluating proposed resource additions. Since 2020, PacifiCorp has been evaluating all newly proposed resource additions in an area at the same time, using a cluster study process that identifies collective solutions that can allow projects that are ready to move forward to do so in a timely fashion. Table 1.1 summarizes the incremental transmission projects in the 2025 IRP preferred portfolio. Currently, the Boardman-to-Hemingway transmission line (B2H) is not included in the preferred portfolio. PacifiCorp is reevaluating the timing and needs analysis underlying B2H because of factors such as changed native load growth and a lack of capacity available on neighboring transmission systems to deliver to load pockets.

Table 1.1 – Transmission Projects Included in the 2025 IRP Preferred Portfolio [1,2]

		Export (MW)	Import (MW)	Interconnect (MW)	Build Investment ($m)	Build (%)	From	To
2026	Utah South - Wasatch Front: 138 kV reinforcement #1	250	250	250	30	100%	Utah South	Wasatch Front
2028	Cluster 1 Area 11: Willamette Valley	0	0	199	14	100%	n/a	n/a
	Cluster 1 Area 14: Summer Lake	400	400	400	111	100%	Summer Lake	Hemingway
	Cluster 1/2/3: Walla Walla	0	0	393	328	100%	n/a	n/a
	Serial queue: Central Oregon	0	0	152	4	100%	n/a	n/a
	Serial/Cluster 1/2: Yakima	0	0	628	64	100%	n/a	n/a
	Utah South - Wasatch Front: 138 kV reinforcement #2	200	200	200	12	100%	Utah South	Wasatch Front
2029	Cluster 2 Area 23: Willamette Valley	0	0	393	2	100%	n/a	n/a
2030	Cluster 2 Area 19: Summer Lake to Central Oregon 500 k	1,500	1,500	670	1,283	100%	Summer Lake	Central OR
	Walla Walla - Yakima 230 kV	400	400	400	142	100%	Walla Walla	Yakima
2031	Serial through Cluster 1 Area 13: Southern Oregon	0	0	231	42	100%	n/a	n/a
2032	Cluster 1 Area 12: Southern Oregon	0	0	300	303	100%	n/a	n/a
2033	Cluster 2 Area 18: Central Oregon 500 kV Substation	0	0	518	372	100%	n/a	n/a
2039	Walla Walla - Central Oregon 500 kV	1,500	1,500	670	1,463	100%	Walla Walla	Central OR
Grand Total		**4,250**	**4,250**	**5,404**	**4,169**			

[1] Export and import values represent total transfer capability. The scope and cost of transmission upgrades are planning estimates. Actual scope and costs will vary depending upon the interconnection queue, the transmission service queue, the specific location of any given generating resource and the type of equipment proposed for any given generating resource.

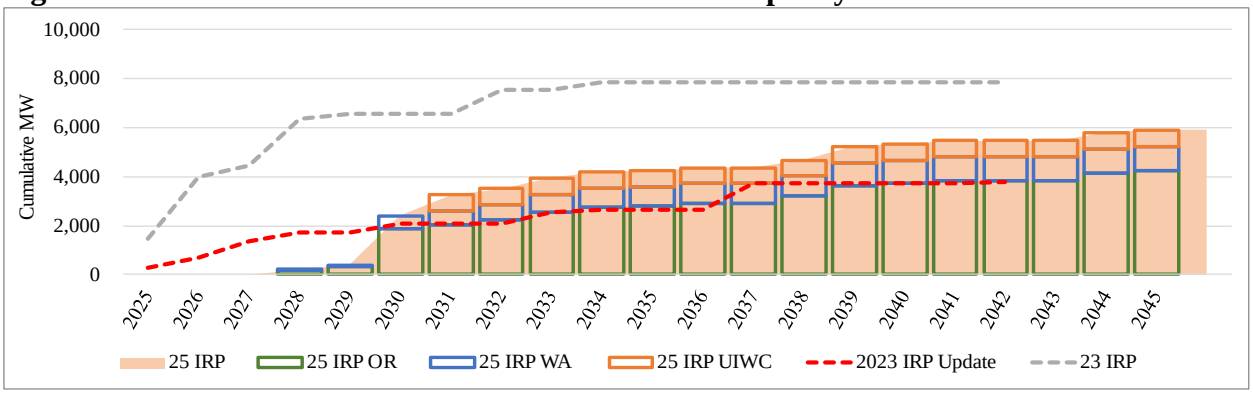
[2] Transmission upgrades frequently include primarily all-or-nothing components, though the cluster study process allows for some project-specific timing and costs.

In Chapter 9 (Modeling and Portfolio Selection Results), a sensitivity analysis evaluates the impacts of significant new data center loads coming online in the 2027-2033 timeframe and supports continuing with permitting Energy Gateway segments, as well as initiating preliminary permitting and development activities for future transmission investments not currently included in the preferred portfolio. These future transmission projects can include development of additional transmission expansion segments and exploration of new routes that have connections to other regions (i.e., connecting southern Oregon to the east with connections to the desert southwest).

New Solar Resources

The 2025 IRP preferred portfolio includes 2,092 MW of new utility scale solar by the end of 2030, 3,822 MW by the end of 2035, and 4,765 MW by the end of 2045. Additionally, the 2025 IRP preferred portfolio includes 320 MW of new small scale solar by the end of 2030, 417 MW by the end of 2035, and 1,157 MW by the end of 2045. These cumulative totals are shown in Figure 1.3.

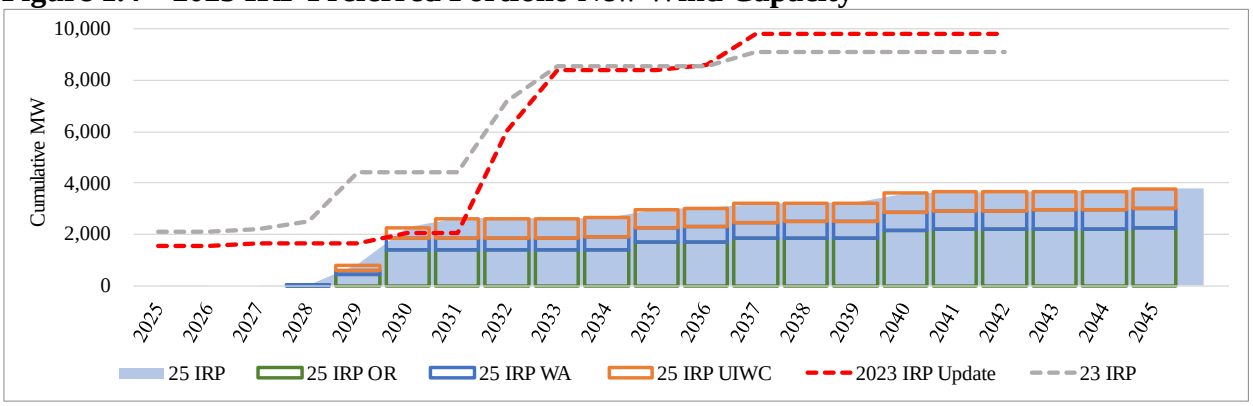
Figure 1.3 – 2025 IRP Preferred Portfolio New Solar Capacity



New Wind Resources

As shown in Figure 1.4, PacifiCorp's 2025 IRP preferred portfolio includes 2,267 MW of new wind generation by the end of 2030, 2,988 MW by the end of 2035, and 3,782 MW of cumulative new wind by the end of 2045. Of note, all wind selections are utility scale.

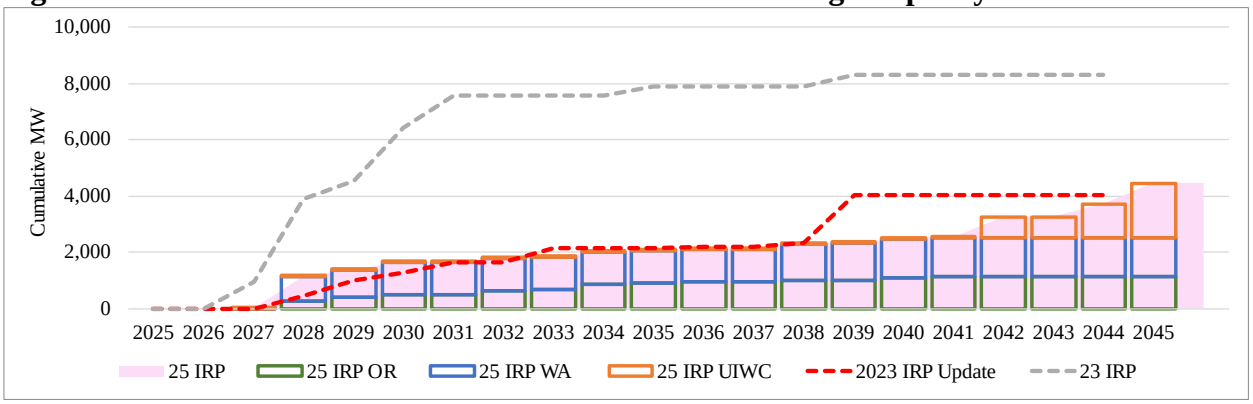
Figure 1.4 – 2025 IRP Preferred Portfolio New Wind Capacity



New Storage Resources

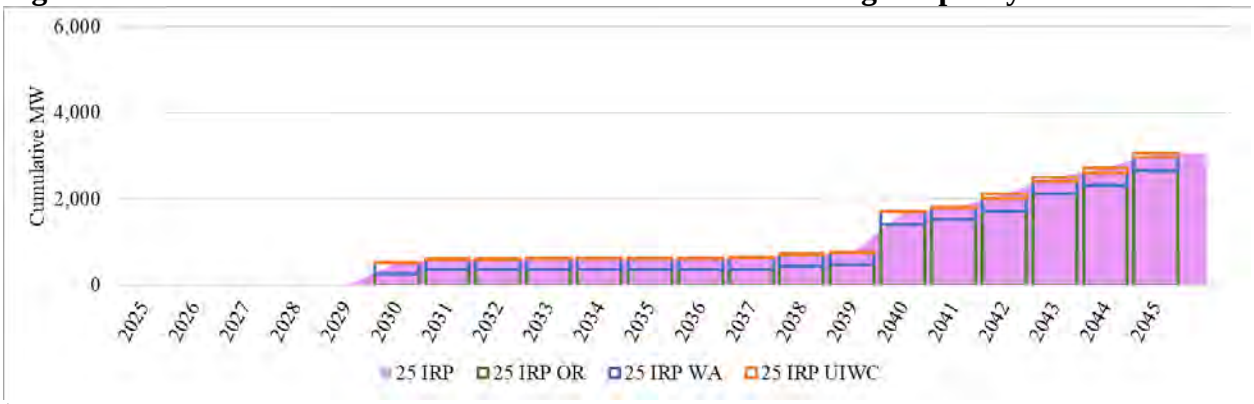
New storage resources in the 2025 IRP preferred portfolio are summarized in Figure 1.5 and Figure 1.6. The 2025 IRP preferred portfolio includes 1,684 MW of new 4-hour storage resources by the end of 2030, 2,072 MW by the end of 2035 and 4,451 MW by the end of 2045. Additionally, the 2025 IRP preferred portfolio includes 511 MW of 100-hour iron air storage by the end of 2030, 616 MW by 2035 and 3,073 MW by 2045. Total storage selections, inclusive of both 4-hour and 100-hour resources, include a total of 7,524 MW of new storage.

Figure 1.5 – 2025 IRP Preferred Portfolio New 4-Hour Storage Capacity[1,2]



[1] The 2023 IRP Update includes 400 MW of PVS battery (Green River solar+storage) in 2026 that has since been signed and thus is not included as new storage capacity in the 2025 IRP.
[2] The 2023 IRP and 2023 IRP Update totals shown in Figure 1.5 include a minimal amount of intermediate duration storage.

Figure 1.6 – 2025 IRP Preferred Portfolio New 24+ Hour Storage Capacity[1]

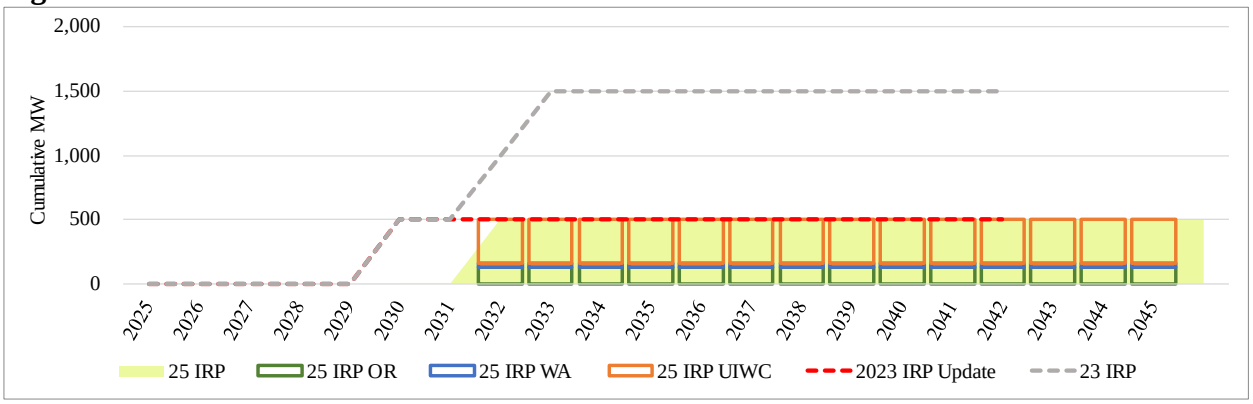


[1]The 2025 IRP preferred portfolio includes 41 MW of renewable peaking by the end of the planning horizon.

New Nuclear Resources

The 2025 IRP includes advanced nuclear as part of its least-cost, least-risk preferred portfolio. As shown in Figure 1.7 , the 500 MW advanced nuclear Natrium™ demonstration project is currently scheduled to come online by the fall of 2031.

Figure 1. – 2025 IRP New Nuclear[1]



[1] While the 500 MW advanced nuclear Natrium™ demonstration project is currently scheduled to come online by the fall of 2031, the PLEXOS model works best with beginning of year start dates for expansion candidates, so a start date of 1/1/2032 was assumed for the Natrium™ demonstration project in modeling.

Demand-Side Management

PacifiCorp evaluates new demand-side management (DSM) opportunities, which includes both energy efficiency and demand response programs, as a resource that competes with traditional new generation and wholesale power market purchases when developing resource portfolios for the IRP. The optimal determination of DSM resources therefore results in the selection of all cost-effective DSM as a core function of IRP modeling. Consequently, the load forecast used as an input to the IRP does not reflect any incremental investment in new energy efficiency programs; rather, the load forecast is reduced by the selected additions of energy efficiency resources in the IRP.

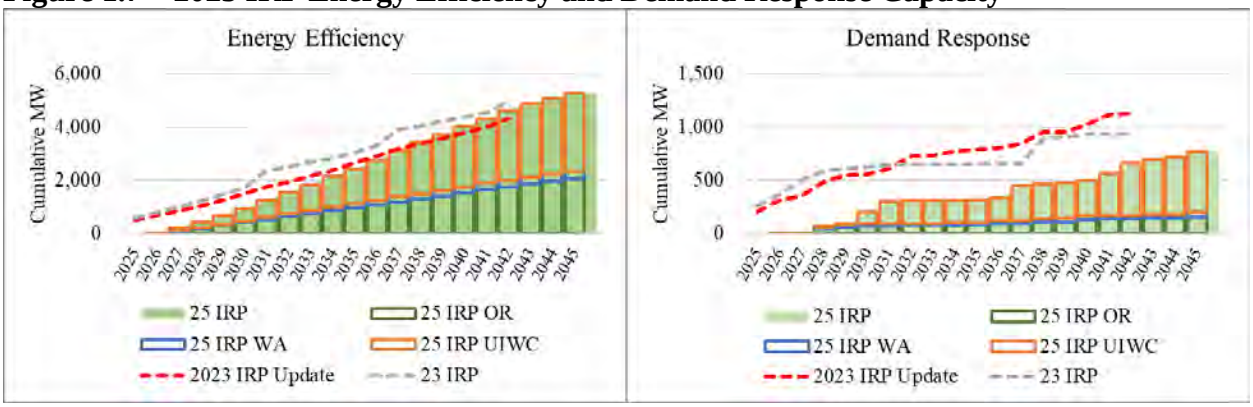
PacifiCorp's load forecast before incremental energy efficiency savings has decreased relative to projected loads used in the 2023 IRP. On average, forecasted system load is down 12.3 percent

and forecasted coincident system peak is down 5.3 percent when compared to the 2023 IRP. Over the planning horizon, the average annual growth rate, before accounting for incremental energy efficiency improvements, is 1.28 percent for load and 1.18 percent for peak. Changes to PacifiCorp's load forecast are driven by a shift in the 2025 IRP in which demand from new large customers is no longer included in the load forecast as those customers are expected to provide or pay for their necessary resources and transmission.

Energy efficiency and demand response programs are important tools for meeting customers' future energy needs. Our innovative approach moves beyond management based on peak loads and focuses on turning demand-response resources into dynamic operating reserves. That's why we're expanding existing demand-response programs and introducing new solutions for customers, particularly as more interconnected technologies enter the market. These programs will reduce our need to buy reserve power on the market and create greater customer benefits. As shown in Figure 1.8, both energy efficiency and demand response show a lower trajectory in the latest forecast, however the trajectories continue to trend upward across the long-term planning horizon.

- In the near-term years of 2025 through 2028, our ongoing conservation and cost-effective demand-response initiatives will seek to deliver:
  - 610 megawatts of energy efficiency from 2025 through 2028
  - 83 megawatts of demand response from 2025 through 2028

Figure 1.7 – 2025 IRP Energy Efficiency and Demand Response Capacity

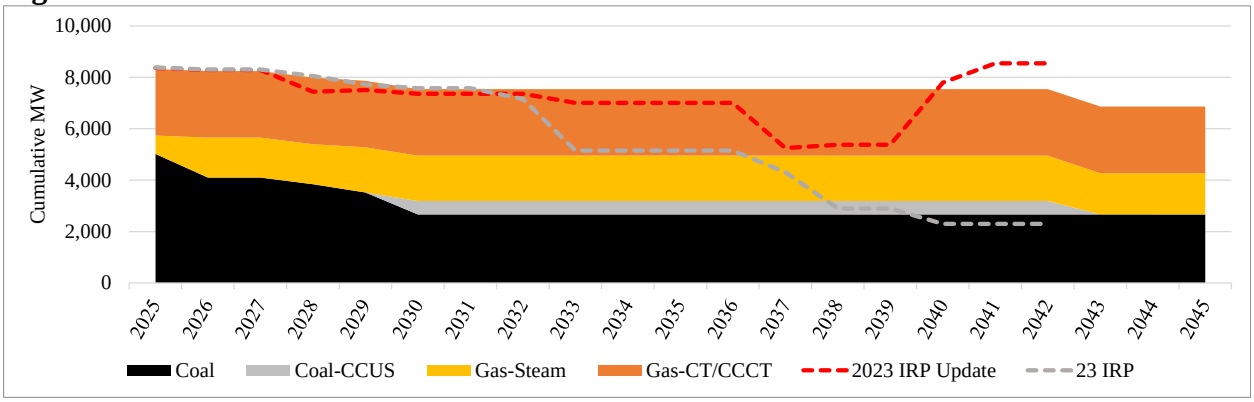


Coal and Gas Exits, Retirements, and Gas Conversions

Coal resources have been an important resource in PacifiCorp's resource portfolio for many years. However, there have been material changes in how PacifiCorp has been operating these assets (i.e., by lowering operating minimums and optimizing dispatch through the WEIM) that has enabled the company to reduce fuel consumption and associated costs and emissions and instead buy increasingly low-cost energy from market participants across the West, which is accessed by our expansive transmission grid. PacifiCorp's coal resources will continue to play a pivotal role in following fluctuations in renewable energy. New for the 2025 IRP, coal-fired units that do not have an enforceable environmental compliance requirement have the option to continue coal-fired operation through the end of the study horizon. Where natural gas supply is expected to be available, an option to convert to natural gas was modeled, and is required for continued operations at units that are required to cease coal-fired operation. As shown in Figure 1.9, the 2025 IRP converts 562 MW of coal fueled generation to natural gas fueled, exits PacifiCorp's share in 386

MW of minority-owned coal, and also assumes retirements of 220 MW at Dave Johnston and 156 MW of Naughton gas conversion by the end of the study horizon. Jim Bridger Units 3 and 4 convert to carbon capture in 2030 and operate during the 12 years of tax credit eligibility, retiring in 2043. The balance of the coal units continues to operate through the end of the study horizon.

Figure 1. – 2025 IRP Preferred Portfolio Thermal Resources



A summary of the coal unit exits, retirements, and conversions in the 2025 IRP preferred portfolio and the 2023 IRP preferred portfolio is shown in Table 1.2. Also shown in Table 1.2 are the coal unit changes which are projected to occur if necessary to comply with the current U.S. Environmental Protection Agency (EPA) greenhouse gas (GHG) emissions regulation under Section 111(d) of the Clean Air Act. In addition to these coal unit exits, retirements, and conversions, the preferred portfolio continues to operate all existing natural gas units through the end of the study horizon.

Table 1.2 – 2025 IRP Coal Resource Results Summary

Majority-Owned Coal			
Unit	2025 IRP Retirement Year		2023 IRP Retirement Year
	Selected w/o 111(d) Regulation	Selected w/ 111(d) Regulation	As Selected
Dave Johnston 1 & 2	Not retired (Gas conversion 2029)	No change	2028
Dave Johnston 3	2027 (Clean air compliance)	No change	2027 (Clean air compliance)
Dave Johnston 4	Not retired	Not retired (Gas conversion 2030)	2039
Hunter 1	Not retired	2032	2031
Hunter 2 & 3	Not retired	Not retired (Alt. fuel conv. 2030)	2032
Huntington 1 & 2	Not retired	Not retired (Alt. fuel conv. 2030)	2032
Jim Bridger 1 & 2	Not retired (Gas conversion 2024)	No change	2037 (Gas conversion 2024)
Jim Bridger 3 & 4	2042 (CCS conversion 2030)	No change	2037 (Gas conversion 2030)
Naughton 1	2042 (Gas conversion 2026)	No change	2036 (Gas conversion 2026)
Naughton 2	Not retired (Gas conversion 2026)	No change	2036 (Gas conversion 2026)
Wyodak	Not retired	2032	2039

Minority-Owned Coal		
Unit	2025 IRP Retirement Year	2023 IRP Retirement Year
	As Input	As Input
Colstrip 3	2025 (Transfer capacity to unit 4)	2025 (Transfer capacity to unit 4)
Colstrip 4	2029 (PacifiCorp exit)	2029 (PacifiCorp exit)
Craig 1	2025 (Assumed end of life)	2025 (Assumed end of life)
Craig 2	2028 (Assumed end of life)	2028 (Assumed end of life)
Hayden 1	2028 (Assumed end of life)	2028 (Assumed end of life)
Hayden 2	2027 (Assumed end of life)	2027 (Assumed end of life)

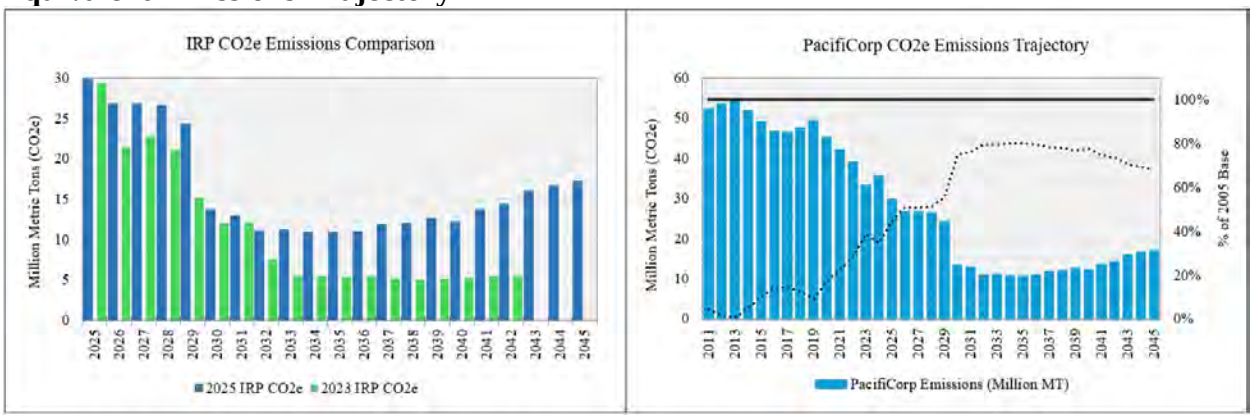
Carbon Dioxide Emissions

The 2025 IRP preferred portfolio demonstrates PacifiCorp's ongoing commitment to providing cost-effective clean energy solutions for its customers, continuing a trend of declining carbon dioxide (CO_2) and CO_2 equivalent (CO_2e) emissions over the next decade. Key drivers of this decline include PacifiCorp's participation in the Energy Imbalance Market (EIM), the ongoing transition to clean energy resources such as renewables, advanced nuclear, battery storage, and transmission, as well as compliance with Regional Haze regulations.

The chart on the left in Figure 1.10 compares projected annual CO_2e emissions between the 2025 IRP and 2023 IRP preferred portfolios. While the 2025 IRP emissions are projected to be slightly higher than those in the 2023 IRP, this difference stems from updates to modeling assumptions. The expected price-policy scenario in the 2025 IRP does not include a CO_2 price or the Ozone Transport Rule, both of which were included in the 2023 IRP. Increased emissions also result from higher unspecified market purchases, assigned a default emissions factor, although market-wide emissions are expected to decline with further renewable energy adoption. PacifiCorp is working with regulators to adjust this factor to reflect the evolving energy market landscape.

The chart on the right in Figure 1.10 presents historical emissions data, assigning emissions to unspecified market purchases, and indicates a long-term decline in system-wide CO2e emissions compared to the company's baseline, with a slight increase toward the end of the planning horizon due to the factors discussed in more detail in Chapter 9.

Figure 1.8 – 2025 IRP Preferred Portfolio CO_2 Equivalent Emissions and PacifiCorp CO_2 Equivalent Emissions Trajectory[1]



[1] PacifiCorp CO_2 equivalent emissions trajectory reflects actual emissions through 2023 from owned facilities, specified sources and unspecified sources. 2024 emissions were not forecasted in the 2025 IRP and therefore reflect the forecast from the 2023 IRP Update. From 2025 through the end of the 21-year planning period in 2045, emissions reflect those from the 2025 IRP preferred portfolio with emissions from specified sources reported in CO_2 equivalent. Market purchases are assigned a default emission factor (0.428 metric tons CO_2e/MWh) – emissions from sales are not removed.

Action Plan

The 2025 IRP action plan identifies specific actions PacifiCorp will take primarily over the next 2-4 years to deliver its preferred portfolio. Action items are based on the size, type and timing of resources in the preferred portfolio, findings from analysis completed over the course of portfolio modeling, and feedback received by stakeholders in the 2025 IRP public-input process. Table 1.3 details specific 2025 IRP action items by resource category.

Table 1.3 – 2025 IRP Action Plan

Action Item	1. Existing Resource Actions
1a	**Colstrip Units 3 and 4:** PacifiCorp will continue to work with co-owners to develop the most cost-effective path toward an exit from the Colstrip project in Montana by 2030.
1b	**Craig Unit 1:** PacifiCorp will continue to work closely with co-owners to seek the most cost-effective path forward toward the 2025 IRP preferred portfolio target exit date of December 31, 2025.
1c	**Naughton Units 1 and 2:** PacifiCorp will continue the process of converting Naughton Units 1 and 2 to natural gas as initiated in Q2 2023, including obtaining all required regulatory notices and filings. Natural gas operations are anticipated to commence spring of 2026. PacifiCorp will initiate the closure of the Naughton South Ash Pond no later than the end of December 2025 when coal operations cease, and will complete closure by October 17, 2028, as required under its pond closure extension submission.
1d	**Carbon Capture and Storage / Low Carbon Portfolio Standard:** PacifiCorp will continue to evaluate the economic and technical feasibility of carbon capture technology on Jim Bridger Units 3 and 4 to comply with Wyoming's low carbon portfolio standard.
1e	**Regional Haze Compliance:** Following the resolution of first planning period regional haze compliance disputes, and the EPA's determination of the states' second planning period regional haze state implementation plans, PacifiCorp will evaluate and model any emission control retrofits, emission limitations, or utilization reductions that are required for coal units. PacifiCorp will continue to engage with the EPA, state agencies, and stakeholders to achieve second planning period regional haze compliance outcomes that improve Class I visibility, provide environmental benefits, and are cost effective.

1f	**Natrium™ Demonstration Project:** By the end of 2025, PacifiCorp expects to finalize a commercial off-take agreement for the Natrium™ project. PacifiCorp will continue to monitor key TerraPower development milestones and will make regulatory filings, as applicable, including, but not limited to, a request for the Public Utility Commission of Oregon to explicitly acknowledge an alternative acquisition method consistent with OAR 860-089-0100(3)(c), and a request for a waiver of a solicitation for a significant energy resource decision consistent with Utah statute 54-17-501.
1g	**Ozone Transport Rule Compliance:** EPA finalized its approval of Wyoming's cross-state ozone state plan on December 19, 2023. This approval means PacifiCorp facilities in Wyoming are not subject to the federal ozone plan requirements. The Tenth Circuit granted a motion to stay EPA's disapproval of Utah's state ozone plan. Utah is not subject to federal ozone requirements while the stay is in place. The Utah ozone case was transferred to the D.C. Circuit in February of 2024, for adjudication of the merits, leaving the stay in place. PacifiCorp will continue to monitor developments in the Utah ozone case and adjust its plans accordingly in response to developments.
1h	**Natural Gas Emissions Compliance Strategies** The 2025 IRP indicates that changes in accounting and/or dispatch of existing natural gas resources may be a beneficial element of Oregon's HB 2021 compliance strategy and to align with evolving state policies. A range of implementation strategies exist, with intertwined implications on resource allocation, market participation, and compliance requirements. PacifiCorp will meet with impacted parties, program administrators, and regulators to enable a refined analysis of the available options to prepare for implementation no later than the start of 2030.
1i	**Federal Greenhouse Gas Emission Compliance:** EPA finalized its regulation for existing coal-fueled steam units under Clean Air Act Section 111(d) in April 2024, though the rule has been challenged in the D.C. Circuit. PacifiCorp will continue to update and evaluate alternatives for affected resources while the legal process continues.
1j	**Dave Johnston Units 1 and 2:** PacifiCorp will initiate the process of converting Dave Johnston Units 1 and 2 to natural gas, including obtaining all required regulatory notices and filings. Natural gas operations are anticipated to commence spring of 2029.

Action Item	2. New Resource Actions
2a	**Customer Preference Request for Proposals:** PacifiCorp is continuously receiving and evaluating requests for voluntary customer programs in Utah and Oregon. PacifiCorp may use the marginal resources from future request for proposals to fulfill customer need. In some cases, customer preference may necessitate issuance of a request for proposals to procure resources within the action plan window. Consistent with Utah Community Renewable Energy Act, PacifiCorp will continue to work with eligible communities to develop program to achieve goal of being net 100 percent renewable by 2030; PacifiCorp filed an application for approval of a resource solicitation process for the program with the Utah Public Service Commission in November 2024. PacifiCorp plans to file an application for the remainder of the program during Q1 2025.
2b	**2025 All-Source Request for Proposals:** PacifiCorp will initiate with individual jurisdictions the process to issue as appropriate by individual jurisdiction need, one or more independent Request for Proposals (RFP) to procure resources aligned with the 2025 IRP preferred portfolio that can achieve commercial operations by the end of December 2029.[3] Individual independent jurisdictional RFP filings will include timelines associated with the respective jurisdictions' process. Considering the differentiated resource needs by jurisdiction identified in the 2025 IRP, scope and targeted resource needs may vary by jurisdiction.

[3] Procurement strategy was a frequent topic during the 2025 IRP public input meeting process and stakeholder feedback. See Appendix M, stakeholder feedback form #17 (Public Utilities Commission of Oregon). A portion of cost-effective demand response resources identified in the 2025 preferred portfolio in 2025 represent planned volumes are expected to be acquired through a previously issued demand response RFP soliciting resources identified in the 2013 IRP. PacifiCorp will pursue all cost-effective demand response resources identified as incremental to existing resources or as an expansion of existing resources offered through approved programs.

Action Item	3. Transmission Action Items
3a	**Local Reinforcement Projects** Initiate Local Reinforcement Projects as identified with the addition of new resources per the preferred portfolio, and follow-on requests for proposal successful bids.
3b	**Gateway West Support** Continue permitting support for Gateway West segments D.3 and E. Initiate preliminary permitting and development activities for future transmission investments not currently included in the preferred portfolio. These future transmission projects can include development of additional Energy Gateway segments and exploration of new routes that have connections to other regions (i.e., connecting southern Oregon to the east with connections to the desert southwest). These activities will enable PacifiCorp to prepare for potential growth in new large loads seeking new service over the next decade.

<table>
<tr><th>Action Item</th><th>4. Demand-Side Management (DSM) Actions</th></tr>
<tr><td>a</td><td>

Energy Efficiency & Demand Response Targets:

PacifiCorp will acquire cost-effective energy efficiency resources targeting annual system energy and capacity selections from the preferred portfolio. PacifiCorp's state-specific processes for planning for DSM acquisitions is provided in Appendix D in Volume II of the 2025 IRP.

PacifiCorp will pursue cost-effective energy efficiency resources.

Year	First-Year Energy Efficiency (GWh)	Annual Capacity (MW)
2025	595	92
2026	573	89
2027	597	209
2028	648	220

PacifiCorp will pursue cost-effective demand response resources targeting annual system capacity selections from the preferred portfolio.[4] Capacity impacts for demand response include both summer and winter impacts within a year and are incremental to those already included as existing.[5]

Year	Annual Incremental Capacity (MW)
2025	18
2026	2
2027	0
2028	63

</td></tr>
</table>

[4] A portion of cost-effective demand response resources identified in the 2025 preferred portfolio in 2025 represent planned volumes are expected to be acquired through a previously issued demand response RFP soliciting resources identified in the 2013 IRP. PacifiCorp will pursue all cost-effective demand response resources identified as incremental to existing resources or as an expansion of existing resources offered through approved programs.

[5] See Appendix D, Table D.3 for the split out between summer and winter capacity.

Action Item	5. Market Purchases
5a	**Market Purchases:** PacifiCorp will acquire short-term firm market purchases for on-peak delivery from 2025-2027 consistent with the Risk Management Policy and Energy Supply Management Front Office Procedures and Practices. These short-term firm market purchases will be acquired through multiple means: Balance of month and day-ahead brokered transactions in which the broker provides a competitive price. Balance of month, day-ahead, and hour-ahead transactions executed through an exchange, such as the Intercontinental Exchange, in which the exchange provides a competitive price. Prompt-month, balance-of-month, day-ahead, and hour-ahead non-brokered bi-lateral transactions.

Action Item	6. Renewable Energy Credit (REC) Actions
6a	**Renewable Portfolio Standards (RPS):** PacifiCorp may pursue unbundled REC RFPs and purchases to meet its state RPS compliance requirements. PacifiCorp will issue RFPs seeking unbundled RECs that will qualify in meeting California RPS targets through 2026 and future compliance periods, as needed.
6b	**Renewable Energy Credit Sales:** Maximize the sale of RECs that are not required to meet state RPS compliance obligations.

CHAPTER 2 – INTRODUCTION

CHAPTER HIGHLIGHTS

- PacifiCorp files an Integrated Resource Plan (IRP) on a biennial basis with the state utility commissions of Utah, Oregon, Washington, Wyoming, Idaho, and California.
- This IRP fulfills the company's commitment to develop a long-term resource plan that considers cost, risk, uncertainty, and the long-run public interest.
- Regulatory staff, advocacy groups, and other interested parties influence the development of the IRP through a collaborative public input process.
- As the owner of the IRP and its action plan, all policy judgments and decisions concerning the IRP are made by PacifiCorp with respect to its obligations to customers, regulators, and shareholders.

INTRODUCTION

In recent integrated resource planning cycles, there has been increased focus on individual state jurisdictional outcomes aligned with both stakeholder and regulatory interest, and state legislation and rulemaking. To recognize and respect this trend, PacifiCorp's 2025 IRP enhances jurisdictional portfolio development and reporting leading to the integration of results into the preferred portfolio. Chapter 8 (Modeling and Portfolio Evaluation) describes the fundamental methodologies used to arrive at state-level initial portfolios and how they are subsequently integrated to form a single coherent plan.

PacifiCorp's selection of the 2025 IRP preferred portfolio is supported by comprehensive data analysis and an extensive public input process, described in the chapters that follow. Chapter 9 (Modeling and Portfolio Selection Results), shows that PacifiCorp's 2025 preferred portfolio continues to include substantial new renewables, facilitated by incremental transmission investments, demand-side management (DSM) resources, significant storage resources (including iron-air technology with 100- hour storage duration), and advanced nuclear.[1]

The 2025 IRP preferred portfolio is in addition to contracted resources, many of which are in Utah. The 100 MW Hornshadow I Solar and 200 MW Hornshadow Solar II facilities are set to come online in 2025, while two facilities combining solar and storage are set to come online in 2025 and 2026: Faraday with 525 MW solar and 150 MW storage and Green River with 400 MW solar and 400 MW storage. Finally, Oregon's Community Solar Program has ten small-scale solar facilities scheduled to come online in 2025 and 2026, totaling approximately 18 MW.

The 2025 IRP preferred portfolio includes the 500 MW advanced nuclear Natrium™ demonstration project, anticipated to achieve online status by summer 2030. Over the 21-year planning horizon, the 2025 IRP preferred portfolio includes 6,379 MW of new wind, 5,492 MW of new solar and 7,668 MW of new storage resources.

New storage includes five battery facilities totaling 520 MW are projected to come online ahead of the peak summer season in 2026: Dominguez BESS (200 MW), Enterprise BESS (80 MW),

[1] See Chapter 7 (Resource Options)

Escalante BESS (80 MW), Granite Mountain BESS (80 MW) and Iron Springs BESS (80 MW). These signed battery storage contracts were committed since the filing of the 2023 IRP update.

To facilitate the delivery of new renewable energy resources to PacifiCorp customers across the West, the preferred portfolio includes additional transmission projects which are described in Volume I, Chapter 1 (Executive Summary), Chapter 4 (Transmission), and Chapter 9 (Modeling and Portfolio Selection Results).

Other significant analysis to support the 2025 IRP includes:

- An updated demand-side management resource conservation potential assessment
- A distributed generation study for PacifiCorp's service territory
- A flexible reserve study
- An updated plant water consumption study
- An energy storage potential evaluation
- An assessment of grid enhancement technologies
- Historic weather years
- An updated load and resource balance

This chapter outlines the components of the 2025 IRP, summarizes the role of the IRP, and provides an overview of the public input process.

2025 Integrated Resource Plan Components

The basic components of PacifiCorp's 2025 IRP include:

- Assessment of the planning environment, market trends and fundamentals, legislative and regulatory developments, and current procurement activities; Volume I, Chapter 3 (Planning Environment)
- Description of PacifiCorp's transmission planning efforts and activities; Volume I, Chapter 4 (Transmission)
- Regional resource adequacy assessments, wildfire mitigation planning and the role of transmission in system reliability and incident recovery; Volume I, Chapter 5 (Reliability and Resiliency)
- Load and resource balance on a capacity and energy basis and determination of the load and energy positions for the front ten years of the twenty-year planning horizon; Volume I, Chapter 6 (Load and Resource Balance)
- Profile of resource options considered for addressing future capacity and energy needs; Volume I, Chapter 7 (Resource Options)
- Description of IRP modeling, including a description of the portfolio development process, cost and risk analysis, and preferred portfolio selection process; Chapter 8 (Modeling and Portfolio Evaluation)
- Presentation of IRP modeling results and selection of PacifiCorp's preferred portfolio; Volume I, Chapter 9 (Modeling and Portfolio Selection Results)
- Presentation of PacifiCorp's 2025 IRP action plan linking the company's preferred portfolio with specific implementation actions, including an accompanying resource acquisition path analysis and discussion of resource procurement risks; Volume I, Chapter 10 (Action Plan)

The IRP appendices, included as Volume II, contain the items listed below:

- Load Forecast (Volume II, Appendix A)
- Regulatory Compliance (Volume II, Appendix B)
- Public Input Process (Volume II, Appendix C)
- Demand-Side Management (Volume II, Appendix D)
- Grid Enhancement (Volume II, Appendix E)
- Flexible Reserve Study (Volume II, Appendix F)
- Plant Water Consumption Study (Volume II, Appendix G)
- Stochastics (Volume II, Appendix H)
- Capacity Expansion Results (Volume II, Appendix I)
- Capacity Contribution (Volume II, Appendix K)
- Distributed Generation Study (Volume II, Appendix L)
- Stakeholder Feedback Forms (Volume II, Appendix M)
- Washington Clean Energy Action Plan (Volume II, Appendix O)
- Oregon Clean Energy Update (Volume II, Appendix P)
- Renewable Portfolio Implementation Plan (Volume II, Appendix R)
- Acronyms (Volume II, Appendix Z)

PacifiCorp is also providing supporting workpapers for the 2025 IRP. These electronically provided materials support and provide additional details for the analysis described within the document. Supporting workpapers are generated for public, confidential, and highly confidential data to be provided as appropriate to each recipient. Confidential and highly confidential data access are provided separately under non-disclosure agreements, or specific protective orders in docketed proceedings. The "Highly Confidential" workpaper category, adopted in the prior 2023 IRP planning cycle, allows the company to provide the maximum amount of access to parties who are not participants in commercial developments or otherwise have direct conflicts of interest regarding commercially sensitive information.

The Role of PacifiCorp's Integrated Resource Planning

PacifiCorp's IRP establishes a proxy resource plan capable delivering adequate and reliable electricity supply at a reasonable cost and in a manner "consistent with the long-run public interest."[2] In this way, the IRP serves as a roadmap for determining and implementing PacifiCorp's long-term resource strategy. In doing so, it accounts for state commission IRP requirements, the current view of the planning environment, corporate business goals, and uncertainty. As a business planning tool, it supports informed decision-making on resource procurement by providing an analytical framework for assessing resource investment tradeoffs, including supporting request for proposal bid evaluation efforts. As an external communications tool, the IRP engages stakeholders in the planning process and guides them through the key decision points leading to PacifiCorp's preferred portfolio of generation, demand-side, and transmission resources.

[2] The Public Utility Commission of Oregon and Public Service Commission of Utah cite "long-run public interest" as part of their definition of integrated resource planning. Public interest pertains to adequately quantifying and capturing for resource evaluation any resource costs external to the utility and its ratepayers. For example, the Public Service Commission of Utah cites the risk of future internalization of environmental costs as a public interest issue that should be factored into the resource portfolio decision-making process.

Public Input Process

The IRP standards and guidelines for certain states require PacifiCorp to have a public input process allowing stakeholder involvement in all phases of plan development. PacifiCorp organized held nine public input meetings, spanning one or two days each, to facilitate information sharing, collaboration, and expectations for the 2025 IRP. The topics covered all facets of the IRP process, ranging from specific input assumptions to the portfolio modeling and risk analysis strategies employed.

In addition to the public input meetings, PacifiCorp used other channels to facilitate resource planning-related information sharing and stakeholder input throughout the IRP process. The IRP webpage is accessible using the following link:

www.pacificorp.com/energy/integrated-resource-plan.html

Messages relevant to PacifiCorp's IRP can sent to the following email address:

irp@pacificorp.com

Additionally, a stakeholder feedback form provides opportunities for stakeholders to submit additional input and ask questions throughout the 2025 IRP public input process. The submitted forms, as well as PacifiCorp's responses to these feedback forms are located on the PacifiCorp's IRP website:

www.pacificorp.com/energy/integrated-resource-plan/comments.html

Summaries of stakeholder feedback forms received, and company responses were provided throughout the public input meeting series and are also available in Appendix M (Stakeholder Feedback Forms). In the 2025 IRP, links to stakeholder feedback forms are provided in footnotes to further tie together stakeholder feedback with the development of the filed IRP. Appendix C (Public Input Process) reports additional details regarding engagement for the 2025 IRP.

CHAPTER 3 – PLANNING ENVIRONMENT

CHAPTER HIGHLIGHTS

- Federal and state tax credits continue to encourage the procurement of wind and solar resources, which will likely dominate U.S. capacity additions for the next decade. Flexible generation, transmission, new storage technologies, and market design changes will need to better integrate these resources into the grid.
- The federal Inflation Reduction Act (IRA) was enacted on August 16, 2022,, creating technology specific tax credits for projects placed in service after December 31, 2021, and technology neutral tax credits for projects placed in service after December 31, 2024. Eligible resources include any technology that generates electricity and does not emit greenhouse gases. The IRA is modeled in all 2025 IRP studies. As of December 2024, the future of some provisions of the IRA remains unknown under the new administration.
- 2024 saw significant new environmental regulation with potential impacts to PacifiCorp's generation resources. These included Greenhouse Gas (GHG) emission standards for existing coal-fired and new gas-fired plants, Mercury and Air Toxics Standards (MATS) revisions, Effluent Limitations Guidelines revisions, Coal Combustion Residuals legacy rule, and the NEPA Phase 2 rule.
- In 2019, the Washington Legislature approved the Clean Energy Transformation Act (CETA), which requires that 100% of retail electricity sales in Washington be 100% renewable and non-emitting by 2045. PacifiCorp filed its inaugural Clean Energy Implementation Plan (CEIP) in December 2021, and expects to file its second CEIP in October 2025, detailing the company's action plan for the next four-year period.
- In 2021, Washington passed the Climate Commitment Act, which established a cap-and-invest program that came into effect January 1, 2023. The Climate Commitment Act does not modify any of PacifiCorp's obligations under CETA, and utilities that are subject to CETA are allocated allowances commensurate with emissions associated with Washington retail load at no cost. The legislation allows – but does not require – linkage with cap-and-trade programs in jurisdictions outside of Washington State.
- In 2021, Oregon passed House Bill 2021, which directs utilities to reduce emissions levels below 2010-2012 baseline levels by 80% by 2030, 90% by 2035, and 100% by 2040. Utilities will also convene a Community Benefits and Impacts Advisory Group. The 2025 IRP includes modeling to support House Bill 2021 which will be expanded upon in PacifiCorp's Oregon Clean Energy Plan submission to be filed within 180 days of the 2025 IRP.
- PacifiCorp and the California Independent System Operator Corporation (CAISO) launched the voluntary western energy imbalance market (WEIM) November 1, 2014, the first western energy market outside of California. Since inception, The WEIM's footprint has grown significantly, generating $3.4 billion in monetary benefits to customers of participating entities. ($1.42 billion total footprint-wide benefits as of August 2, 2021). A significant contributor to EIM benefits is transfers across balancing authority areas, providing access to lower-cost supply, while factoring in the cost of compliance with greenhouse gas emissions regulations when energy is transferred into the CAISO balancing

authority area. Building on the success of WEIM, in 2022 PacifiCorp, along with CAISO and other stakeholders, collaborated to develop a market design for an extended day ahead market (EDAM) that CAISO plans to launch in 2025.

Introduction

This chapter profiles the major external influences that affect PacifiCorp's long-term resource planning and recent procurement activities. External influences include events and trends affecting the economy, wholesale power and natural gas prices, and public policy and regulatory initiatives that influence the environment in which PacifiCorp operates.

Major issues in the power industry include resource adequacy and associated standards for the Western Electricity Coordinating Council (WECC). Future natural gas prices, the role of gas-fired generation, the role of emerging technologies, and the net costs of renewables and battery technologies also factor into the selection of the portfolio that best achieves least-cost, least-risk planning objectives.

On the government policy and regulatory front, a further significant issue in the power industry and facing PacifiCorp continues to be planning for eventual, but highly uncertain, climate change policies. This chapter provides discussion on climate change policies as well as a review of significant policy developments for currently regulated pollutants. This chapter also provides updates on the status of renewable portfolio standards and resource procurement activities.

Wholesale Electricity Markets

PacifiCorp's system operates in conjunction with a multifaceted market. Operations and costs are tied to a larger electric system known as the Western Interconnection which functions, on a day-to-day basis, as a geographically dispersed marketplace. Each month, millions of megawatt-hours of energy are traded in the wholesale electricity market. These transactions yield economic efficiency by ensuring that resources with the lowest operating cost are serving demand throughout the region and by providing reliability benefits that arise from a larger portfolio of resources.

PacifiCorp actively participates in the wholesale market by making purchases and sales to minimize costs and to keep its supply portfolio in balance with customers' expectations. This interaction with the market takes place on time scales ranging from sub-hourly to years in advance. Without the wholesale market, PacifiCorp – or any other load serving entity – would need to construct or own an unnecessarily large margin of supplies that would go unused in all but the most unusual circumstances and would substantially diminish its capability to cost effectively match delivery patterns to the profile of customer demand.

The benefits of access to an integrated wholesale market have grown with the increased penetration of intermittent generation such as solar and wind. Intermittent generation can come online and go offline abruptly in congruence with changing weather conditions. Federal and state (where applicable) tax credits and improved technology performance have continued to place wind and solar energy generators "in the money" in areas of high resource potential. As such, wind and solar will continue to play a dominant role in power supply options over the next decade. To better integrate these resources into the larger grid requires more flexible generation, transmission, evolving storage technologies, and market design changes.

Regarding transmission, there are long-haul, renewable-driven transmission projects in advanced development in the U.S. WECC. These transmission lines ultimately connect areas of high renewable energy potential and low population density to areas of high population density with less renewable potential. This includes PacifiCorp's 416-mile high-voltage 500-kilovolt (kV) Gateway South project and the 59-mile high-voltage 230-kV Gateway West Segment D.1 project, brought in-service in late 2024. These transmission projects will provide greater system-wide flexibility transferring energy from Wyoming to load centers located in Utah.

The intermittency of renewable generation has also given rise to a greater need for fast-responding and long-duration storage, which is essential for grid stability and resiliency. Pumped storage has been the traditional storage option and there are multiple projects being developed throughout the West. Of remaining mechanical, thermal, and chemical storage options, lithium-ion (Li-ion) batteries have shown the most promise in terms of cost and performance. In 2013, the California Public Utility Commission (CPUC) required investor-owned utilities to procure 1,325 MW of storage by 2020; that requirement has been satisfied. As of 2022, nine states had implemented energy storage targets or mandates, with action being considered in at least one other.[1] In California, the Elkhorn Battery project became fully operational for Pacific Gas & Electric (PG&E) in April of 2022. The Moss Landing project in Monterey County includes 182.5 MW of Tesla Megapack energy storage.[2] Hybrid co-located solar photovoltaic (SPV) and battery systems are now in Utah, Hawaii, Arizona, Nevada, California, and Texas.

In 2018, the Federal Energy Regulatory Commission (FERC) directed regional transmission organizations (RTO) and independent system operators (ISO) to develop market rules for the participation of energy storage in wholesale energy, capacity, and ancillary services markets[3]. The FERC gave operators nine months to file tariffs and another year to implement – essentially opening wholesale markets to energy storage. Operators' proposed tariffs have varied substantially among regions with PJM requiring a 10-hour continuous discharge capability while New England requires a continuous 2-hour capability. Later, in May 2019, the FERC issued an order generally affirming the earlier order to establish reforms to remove barriers to the participation of electric storage resources in certain organized wholesale markets. PacifiCorp continues to evaluate the cost effectiveness of several energy storage systems, including pumped storage, stand-alone Li-ion batteries, flow batteries, iron-air storage and other long-duration storage, as well as energy storage co-located with generating resources.

Increased renewable generation has also contributed to the need for balancing sub-hourly demand and supply across a broader and more diverse market. For balancing purposes, PacifiCorp combined its resources with those of the CAISO through the creation of the Energy Imbalance Market (EIM). The EIM became operational November 1, 2014, and since that time has seen NV Energy, Puget Sound Energy, Arizona Public Service, Portland General Electric, Powerex, Idaho

[1] California, New Jersey, New York, Massachusetts, Oregon, Nevada, Virginia, Connecticut, and Maine have either mandated or set energy storage targets, while Arizona is considering the implementation of targets.
[2] In addition to Elkhorn, PG&E has contracts for more than 3,330 MW of battery storage being deployed statewide through 2024, more than 900 MW of which has been connected to California's electric grid. The Mercury News, March 8, 2023; PG&E ushers in landmark Tesla battery energy storage system at Moss Landing (mercurynews.com)
[3] 162 FERC ¶ 61,127 United States of American Federal Energy Regulatory Commission, 18 CFR Part 35 [Docket Nos. RM16-23-000; AD16-20-000; Order No. 841] *Electric Storage Participation in Markets Operated by Regional Transmission;* Organizations and Independent System Operator (Issued February 15, 2018)

Power, Balancing Authority of Northern California, Salt River Project, Seattle City Light, Los Angeles Department of Water and Power, Northwestern Energy, and Public Service Company of New Mexico, Avista Utilities, Tucson Electric Power, Turlock Irrigation District, Tacoma Power, Bonneville Power Administration, Avangrid Renewables, El Paso Electric, and Western Area Power Administration join the EIM. Black Hills Power plans to join the EIM in 2026. The multi-service area footprint brings greater resource and geographical diversity allowing for increased reliability and cost savings in balancing generation with demand using 15-minute interchange scheduling and five-minute dispatch. CAISO's role is limited to the sub-hourly scheduling and dispatching of participating EIM generators. CAISO does not have any other grid operator responsibilities for PacifiCorp's service areas. As part of other EIM participating entities, PacifiCorp is also participating in the CAISO stakeholder process to establish an Extended Day-Ahead Market (EDAM), which is currently in the phase of implementation activities and expected to onboard participants in 2026.

As with all markets, electricity markets face a wide range of uncertainties. In February 2021, winter storm Uri caused an unprecedented 24.1% decline in marketed natural gas production in Texas, a drop of 186.7 billion cubic feet (Bcf) compared to the previous month. This decline contributed to the largest monthly decline in natural gas production on record in the Lower 48 states. This weather event caused widespread disruptions in energy supply and demand, including extended electric power blackouts in Texas.

The Western United States experienced an excessive heat event during the first week of September 2022. As a result, record temperatures were recorded on September 4th through September 7th, reaching as high as 114º F in Sacramento, California, 110º F in Burbank, California, and 107º F in Salt Lake City, Utah. With these record setting temperatures, the West saw a widespread surge in electricity demand and correspondingly tight supply conditions. Maintaining reliability across the region during this period was a testament to the benefits of energy markets, geographic diversity across the West, and conservation efforts during extreme heat events.

Market participants routinely study demand uncertainties driven by weather and overall economic conditions. The North American Electric Reliability Corporation (NERC) publishes an annual assessment of regional power reliability, and any number of data services are available that track the status of new resource additions[4]. In NERC's latest release, the WECC region was classified as "elevated risk", in which shortfalls may occur in extreme conditions.

The Western Resource Adequacy Program (WRAP)[5] will also provide market participants insight into potential supply constraints and give participants some assurance that sufficient resources have been procured for the program to maintain a 1-in-10-year loss of load expectancy standard. In addition to binding load and resource showings for the upcoming season, the WRAP will conduct advisory two- and five-year resource adequacy assessments for the footprint that will allow participants to better plan for the future needs of their systems. The Forward Showing program will ensure participants procure sufficient resources to meet a footprint wide reliability standard, and the Ops Program will facilitate transfers between entities in a resource deficit and those with excess resources.

[4] 2020 Long-term Reliability Assessment, December 2020, North American Electric Reliability Assessment
[5] https://www.westernpowerpool.org/about/programs/western-resource-adequacy-program

In addition to reliability planning, there are externalities that can heavily influence the direction of future prices. One such uncertainty is the evolution of natural gas prices over the course of the IRP planning horizon. Natural gas-fired generation and gas prices have been a critical determinant of western electricity prices, and this is expected to continue over the term of this plan's decision horizon. While the share of natural gas in the resource western resource mix is expected to fall by the end of the horizon because of increasing renewable resource buildout, natural gas will remain on the margin in many hours, particularly critical hours when renewable resource output is limited. Another critical uncertainty that weighs heavily on the 2025 IRP, as in past IRPs, is the uncertainty surrounding future greenhouse gas policies, both federal and/or state. PacifiCorp's official forward price curve (OFPC) does not assume a federal carbon dioxide (CO_2) policy, but other price scenarios developed for the IRP consider impacts of potential future federal and state policies which drive additional costs and restrictions of emissions. However, PacifiCorp's OFPC does include enforceable state climate programs that have been signed into law[6].

Power Market Prices

Mild weather, strong production, and limited exports caused high storage levels in the fossil gas market, resulting in low gas prices throughout 2024. Low fuel prices coupled with mild demand led to an annually averaged 34% decrease in on-peak spot prices across the Non-CAISO WECC trading hubs in 2024, as seen in Table 3.1.

Table 3.1 - 2023 and 2024 Monthly Average On-Peak Spot Prices ($/MWh)

Month	2023	2024	Difference	Percent
Jan	135.23	137.27	2.05	2%
Feb	84.41	41.95	-42.46	-50%
Mar	76.51	25.05	-51.46	-67%
Apr	79.53	18.57	-60.97	-77%
May	21.60	20.48	-1.13	-5%
Jun	38.87	31.13	-7.74	-20%
Jul	93.02	67.88	-25.13	-27%
Aug	88.59	48.50	-40.09	-45%
Sep	51.76	52.55	0.78	2%
Oct	78.57	46.24	-32.33	-41%
Nov	70.90	35.19	-35.71	-50%
Dec	52.12	47.50	-4.62	-9%
Annual	**72.59**	**47.69**	**-24.90**	**-34%**

**As of December 16, 2024*

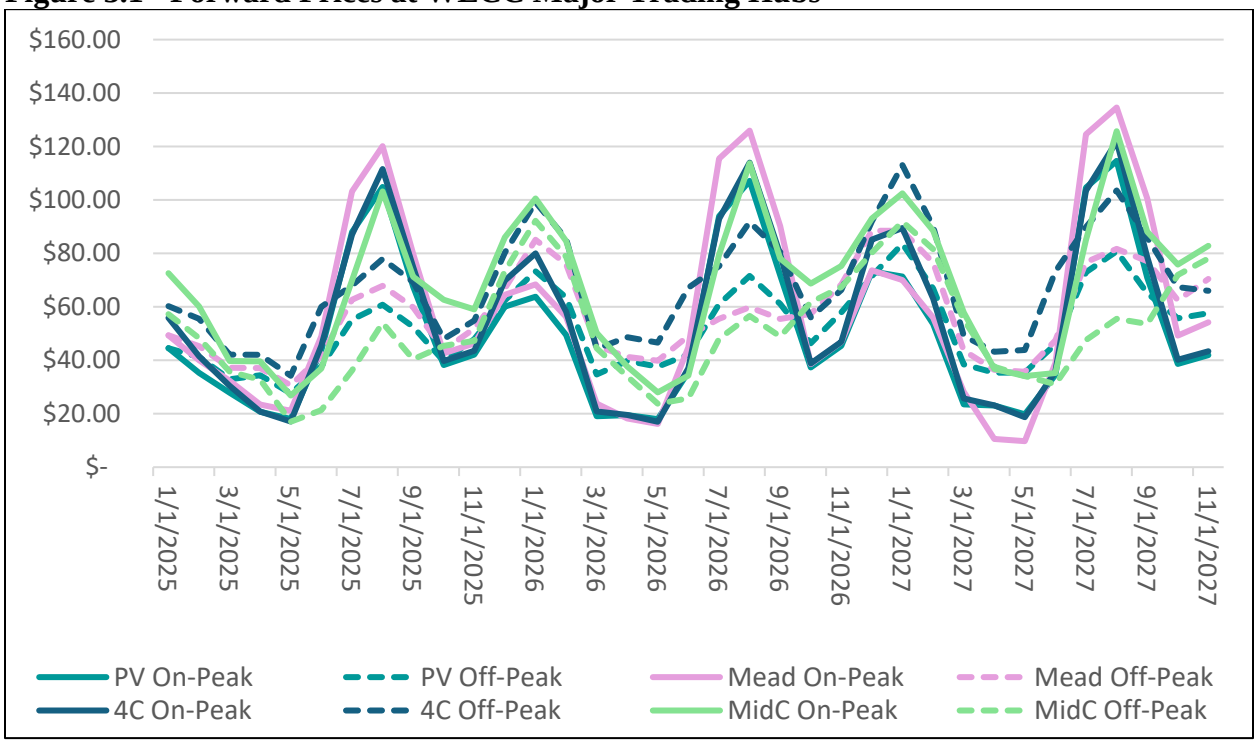
Source: SNL

Barring major geo-political disruptions or other sustained economic drivers, forecasted wholesale power prices are expected to increase slightly relative to 2024 peaks and will follow seasonal weather trends with higher prices over the summer months. Broker price spreads indicate August

[6] California and Washington carbon allowance price forecasts are applied when appropriate. Washington allowance prices assumed the forecast published by Vivid Economics, commissioned by Washington Department of Ecology as part of its CCA Regulatory Impact Analysis for WAC 173-446, which was the best available information at the time of modeling. Available at https://apps.ecology.wa.gov/publications/documents/2202047.pdf.

2025 On-Peak power prices at Palo Verde, Mead, Four Corners, and Mid-Columbia are all trading around $105-$120 per MWh.

Figure 3.1 - Forward Prices at WECC Major Trading Hubs



Source: OTC, Siemens PTI

Table 3.2 reports the quarterly on-peak and off-peak price spread across the major WECC hubs, driving the peaks and valleys observed in Figure 3.1 above.

Table 3.2 - 2025-2027 Forward Price Spread ($/MWh)

	Palo Verde		Mead		4 Corners		Mid-Columbia	
Date	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
1/1/2025	$ 44.57	$ 44.53	$ 49.32	$ 49.35	$ 55.87	$ 60.23	$ 72.60	$ 57.25
5/1/2025	$ 18.04	$ 27.62	$ 21.12	$ 30.62	$ 17.05	$ 34.20	$ 26.81	$ 17.02
8/1/2025	$104.89	$ 60.81	$120.14	$ 67.85	$111.56	$ 77.93	$103.20	$ 53.99
11/1/2025	$ 42.14	$ 47.94	$ 46.28	$ 51.86	$ 43.55	$ 54.89	$ 59.08	$ 47.28
1/1/2026	$ 63.81	$ 73.32	$ 68.41	$ 85.12	$ 79.99	$ 99.17	$100.52	$ 92.19
5/1/2026	$ 17.98	$ 37.62	$ 16.18	$ 39.84	$ 17.00	$ 46.59	$ 27.99	$ 23.71
8/1/2026	$107.13	$ 71.57	$125.96	$ 59.86	$113.94	$ 91.72	$113.74	$ 56.61
11/1/2026	$ 45.38	$ 57.92	$ 46.83	$ 68.32	$ 46.89	$ 66.32	$ 75.27	$ 67.37
1/1/2027	$ 71.36	$ 83.56	$ 70.01	$ 88.44	$ 89.44	$113.02	$102.48	$ 91.87
5/1/2027	$ 19.80	$ 35.40	$ 9.73	$ 35.70	$ 18.71	$ 43.83	$ 34.07	$ 34.10
8/1/2027	$114.63	$ 80.80	$134.58	$ 81.71	$121.91	$103.55	$125.72	$ 55.51
11/1/2027	$ 41.95	$ 57.62	$ 54.19	$ 70.41	$ 43.35	$ 65.97	$ 82.83	$ 78.10

Source: OTC

Power Market Dynamics

Non-CAISO WECC Generation and Capacity Mix

The generation mix in the non-CAISO WECC region reflects the influence of state RPS (renewable portfolio standard) and emissions policies. In 2023, natural gas resources provided about 31% of generated energy followed by hydro at 22%, coal at 18%, and wind at 12%. Natural gas and coal share is expected to decrease slightly, with non-hydro renewables expected to replace this energy throughout 2030.

Figure 3.2 - National RPS Targets

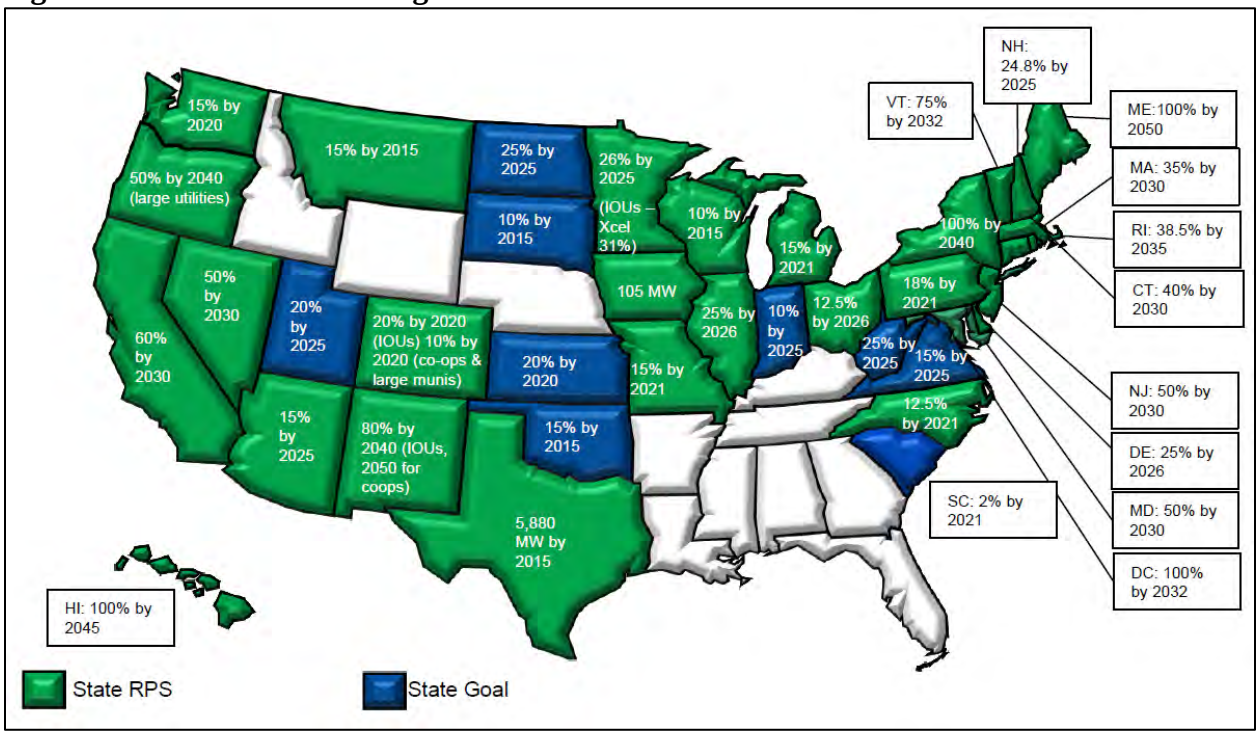
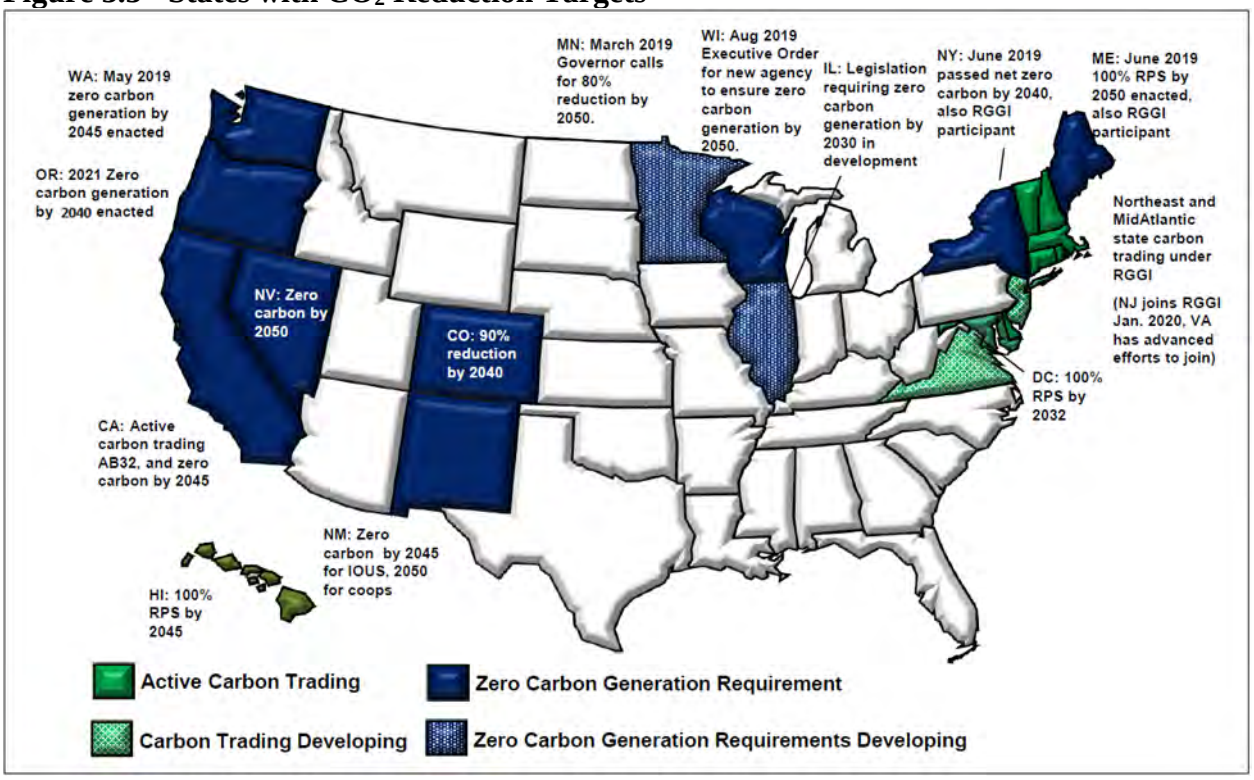
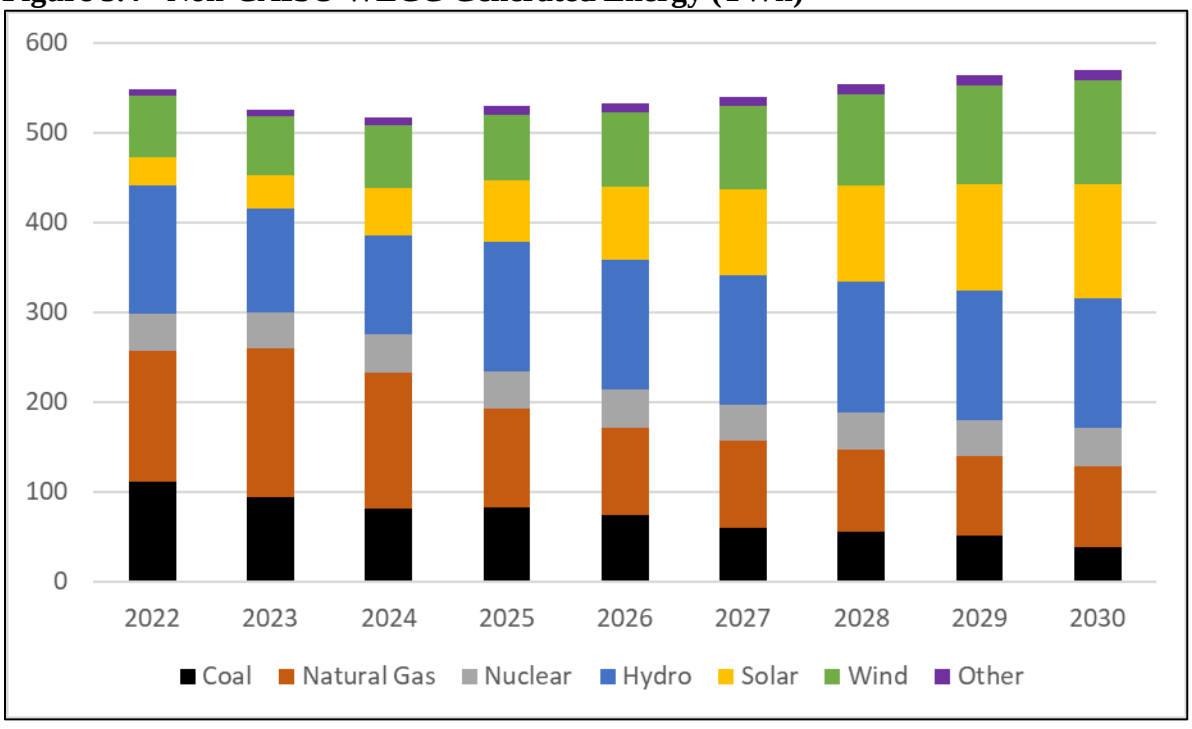


Figure 3.3 - States with CO_2 Reduction Targets



Source: Siemens PTI

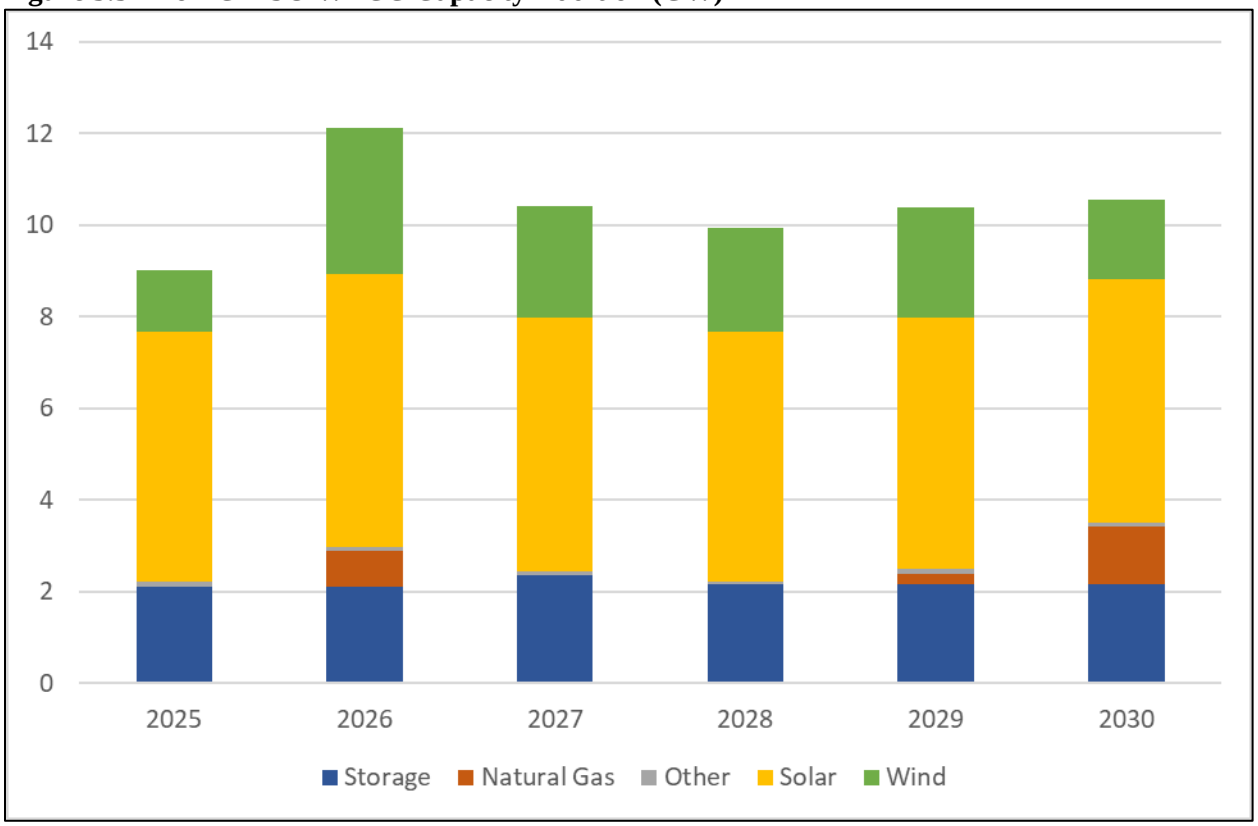
Figure 3.4 - Non-CAISO WECC Generated Energy (TWh)



Source: IHS Markit, SNL, Siemens PTI

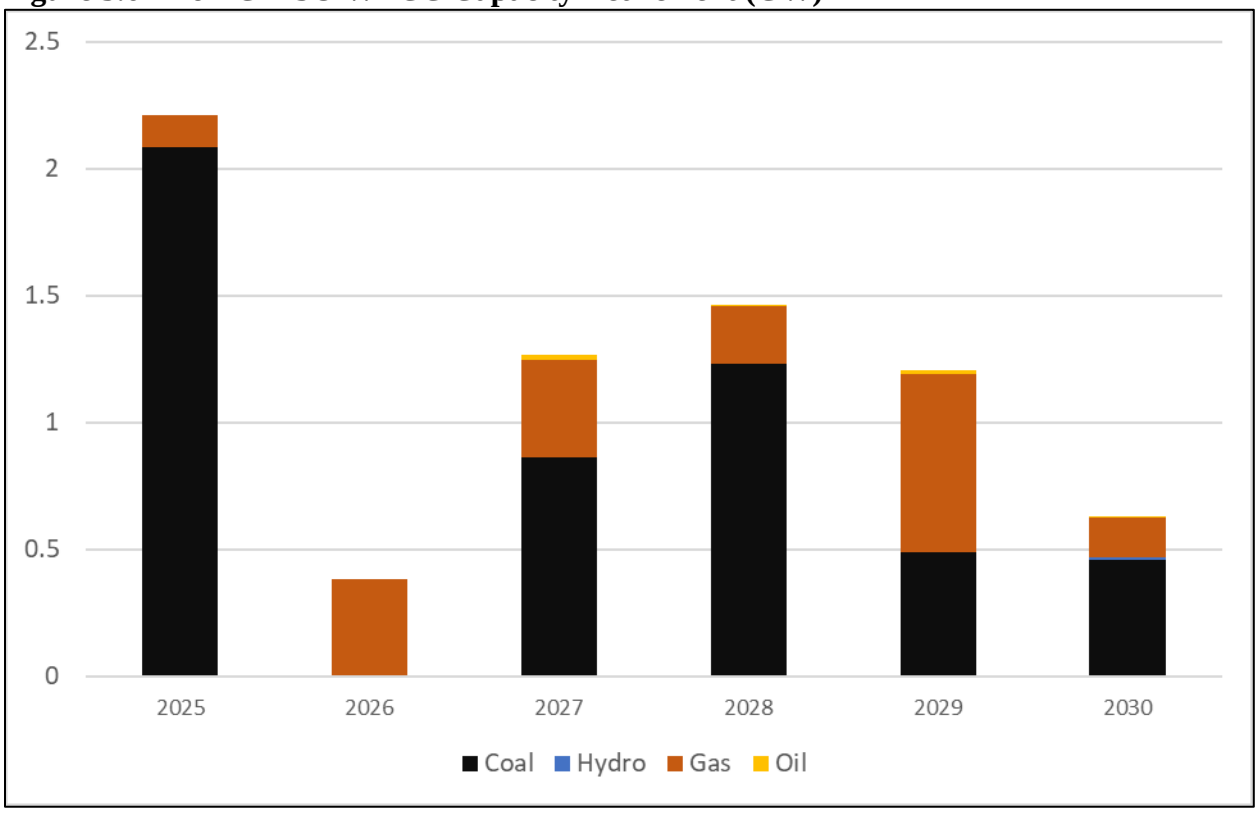
In 2023, 3.5 GW of solar resources and 600 MW of wind were added in the non-CAISO WECC, with similar quantities coming online through October 2024. Into 2025, Siemens expects approximately 3.6 GW of wind and 2.1 GW of solar to come online based on activity in regional interconnection queues. Storage capacity additions have also been significant, with 1.4 GW of storage capacity brought online in 2022 and 1.9 GW online through October 2024. Minimal fossil fuel capacity came online in 2023, and that trend may continue through 2030 if carbon reduction goals continue to drive renewable additions.

Figure 3.5 - Non-CAISO WECC Capacity Addition (GW)



Source: IHS Markit, SNL, Siemens PTI

Figure 3.6 - Non-CAISO WECC Capacity Retirement (GW)



Source: IHS Markit, SNL, Siemens PTI

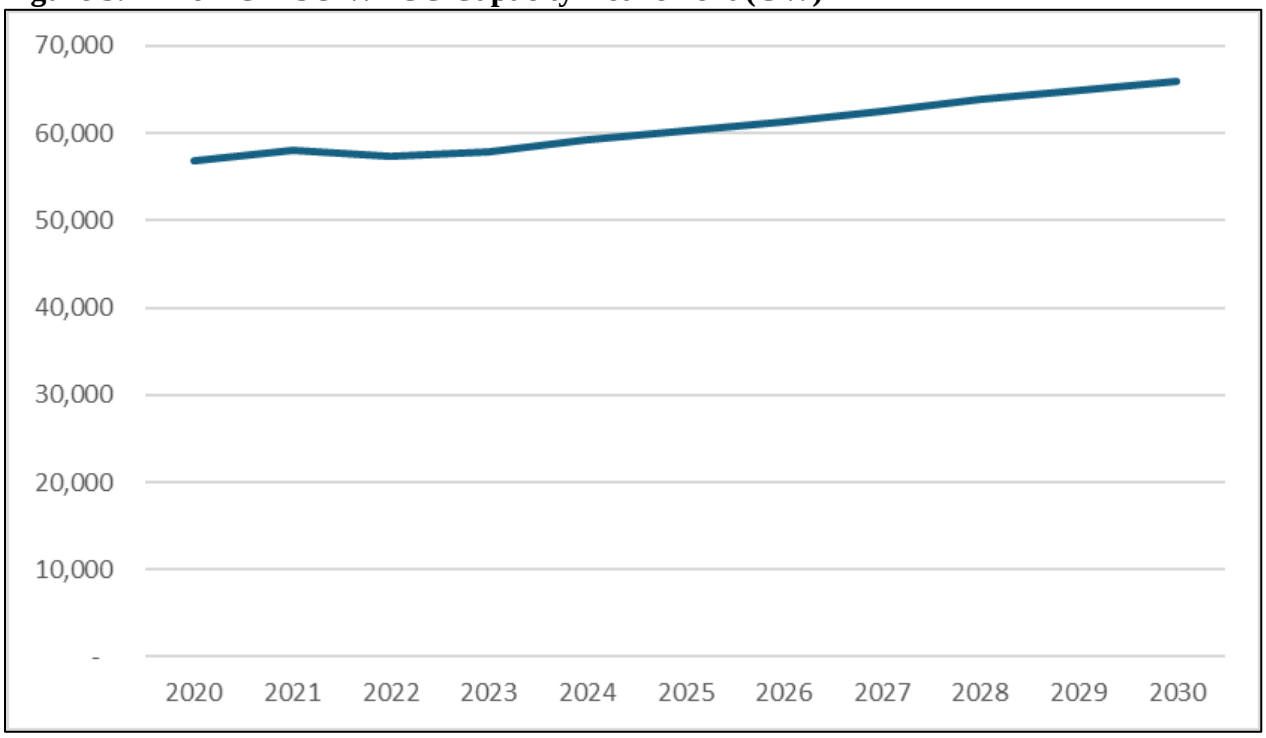
Emissions and Environment

Cool weather and low natural gas prices in 2023 led to decreased emissions and low demand for allowances. In addition, the finalization of the Good Neighbor Plan in March 2023 contributed to an 18% NOx emission reduction within the ten implemented states. On April 25, 2024, the U.S. Environmental Protection Agency (EPA) unveiled its final rule to regulate greenhouse gas (GHG) emissions from power plants under Section 111 of the Clean Air Act. The updated rule mandates that coal-fired baseload units achieve 90% carbon capture and storage (CCS) by 2032. It also provides an option for plants scheduled for retirement by 2039 to co-fire up to 40% natural gas as a transitional measure to reduce emissions.

Non-CAISO WECC Demand Forecast

After years of relatively stagnant demand nationwide, recent additions of loads—such as data centers, manufacturing facilities, and electrification initiatives—have caused load forecast projections to surge. According to regional outlooks, the non-CAISO WECC region is anticipated to experience a compound annual growth rate (CAGR) of 1.8% from 2024 to 2030. Recent Integrated Resource Plans (IRPs) from utilities across the region, including Nevada Energy, Arizona Public Service, show higher-than-usual load growth expectations, largely due to significant new load additions expected to come online in the coming years.

Figure 3.7 - Non-CAISO WECC Capacity Retirement (GW)



Source: Siemens PTI

Forward Influence of the IRA

In August 2022, the US Congress Passed the Inflation Reduction Act ("IRA"). The notable near-term impacts of the IRA are to allow all non-carbon emitting resources and energy storage resources to select either production tax credits or investment tax credits. Production tax credits are expected to provide greater benefits for wind, solar, and many other generation technologies and may contribute to suppressed market prices during periods of renewable resource oversupply as generators may be willing to accept negative attempt to avoid losing production tax credits.

As of November 2024, the future of some provisions of the IRA remains uncertain under the new administration. While a repeal of the IRA is unlikely as that would require congressional approval, the Trump administration could slow the payment of grants and loans or rescind or modify regulations and guidance issued to date on how to implement provisions of the IRA. This action would make it difficult for companies and individuals to plan with certainty with respect to claiming tax credits for investments in new renewable and non-emitting technologies including EVs and offshore wind. A US policy movement away from federal climate initiatives could also enhance China's global dominance in clean energy industries such as solar panels and EVs, while potential new import tariffs could hinder the deployment of energy generation and other technologies supported by the IRA.

Natural Gas Prices

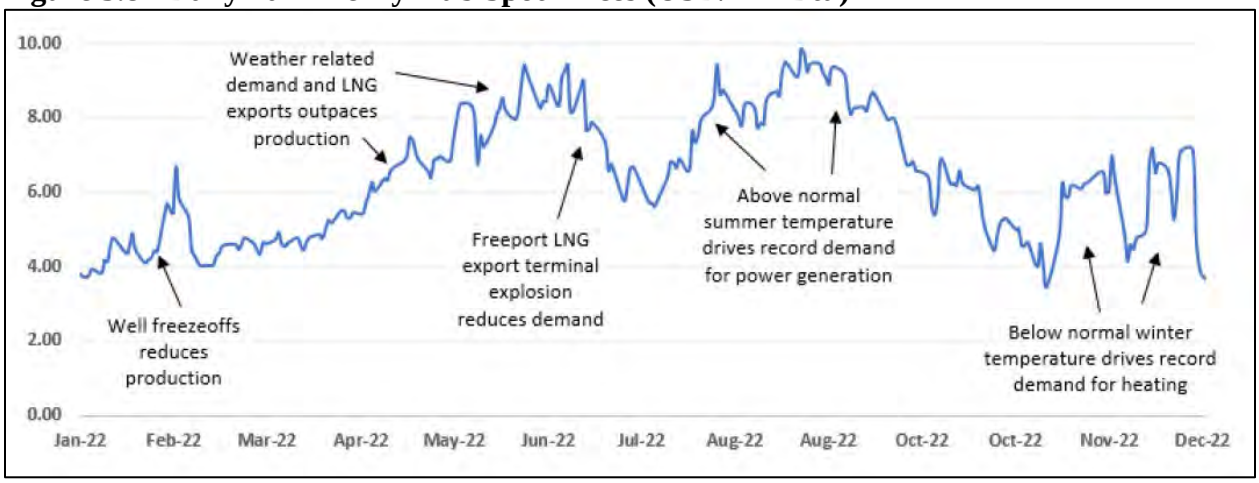
2022 Summary

In the first quarter of 2022, demand for natural gas surpassed production in the US due to well freeze-offs in January and February. High withdrawals of natural gas from storage during this time

caused prices to increase. Continued demand for U.S. liquified natural gas (LNG) exports into Europe due to Russia's war on Ukraine, as well as increasing weather-driven demand, caused upward price pressure.

In the second quarter, starting in May, weather-related demand for natural gas for electric generation as well as uncertainty around storage injections led to an increase in natural gas prices. The Henry Hub spot prices, as you can see in Figure 3.8, rose to over $9/MMBtu. However, in late June, the second largest LNG export terminal in the US, accounting for 17% of total LNG export capacity, suffered a tragic explosion which took it offline. As such prices fell to below $6/MMBtu. For the first half of 2022, the U.S. was the largest exporter of LNG in the world, and over two-thirds of the cargoes headed to Europe.

Figure 3.8 - Daily 2022 Henry Hub Spot Prices (USD/MMBtu)



Source: S&P Global, Siemens PTI

The price of natural gas quickly rebounded in July and August, because of a heat wave in many parts of The U.S., which resulted in record high demand for power generation. The Western States of the U.S. were particularly affected by this not only due to higher demand for power but also from reduced supply of hydro resources due to continuing drought.

Despite these challenges, US Lower 48 supply surpassed pre-pandemic levels in the first half of 2022, led by gas production growth as higher prices spurred increased rig activity. Rig activity was more pronounced in low-cost basins such as Permian (Texas/New Mexico) and Haynesville (Louisiana) as they have better infrastructure to access demand areas.

Production growth slowed over the second half of 2022 as inflation, labor, and materials shortages, and service sector constraints continued to impact producers, keeping overall domestic production hovering around 100 Bcf/d. Natural gas delivery in the US is complex due to the number of supply sources and pipelines that transport gas to various hubs around the country. As such prices at Henry Hub do impact prices in the West as the same source that supplies the gulf coast region can also supply the Western states.

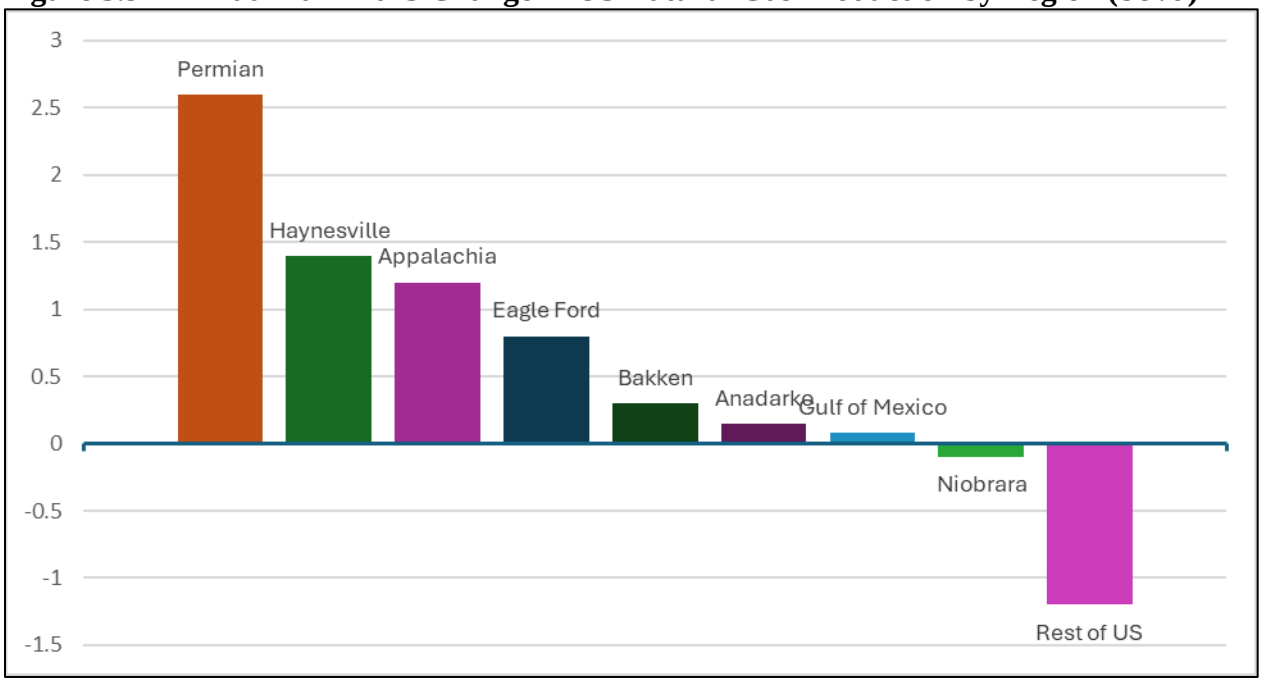
However, there may be regional differences in price due to pipeline constraints. For instance, in December 2022 and January 2023, while most of the country had above-normal temperatures, California experienced wet and below-normal cold temperatures that significantly increased

demand for natural gas. This higher demand, the constraint on pipelines, and reduce storage levels contributed to significantly higher prices that the west is currently experiencing.

2023 Summary

In 2023, U.S. natural gas prices saw a significant drop compared to the previous year, with the benchmark Henry Hub price averaging $2.57 per million British thermal units (MMBtu), a steep 62% decline from 2022. This price decline was largely driven by record-high production levels, which reached an average of 104 billion cubic feet per day (Bcf/d), 4% higher than the previous year. This production increase was particularly notable in key regions like the Permian, Haynesville, and Appalachia, where technological advancements and strong oil prices supported higher outputs.

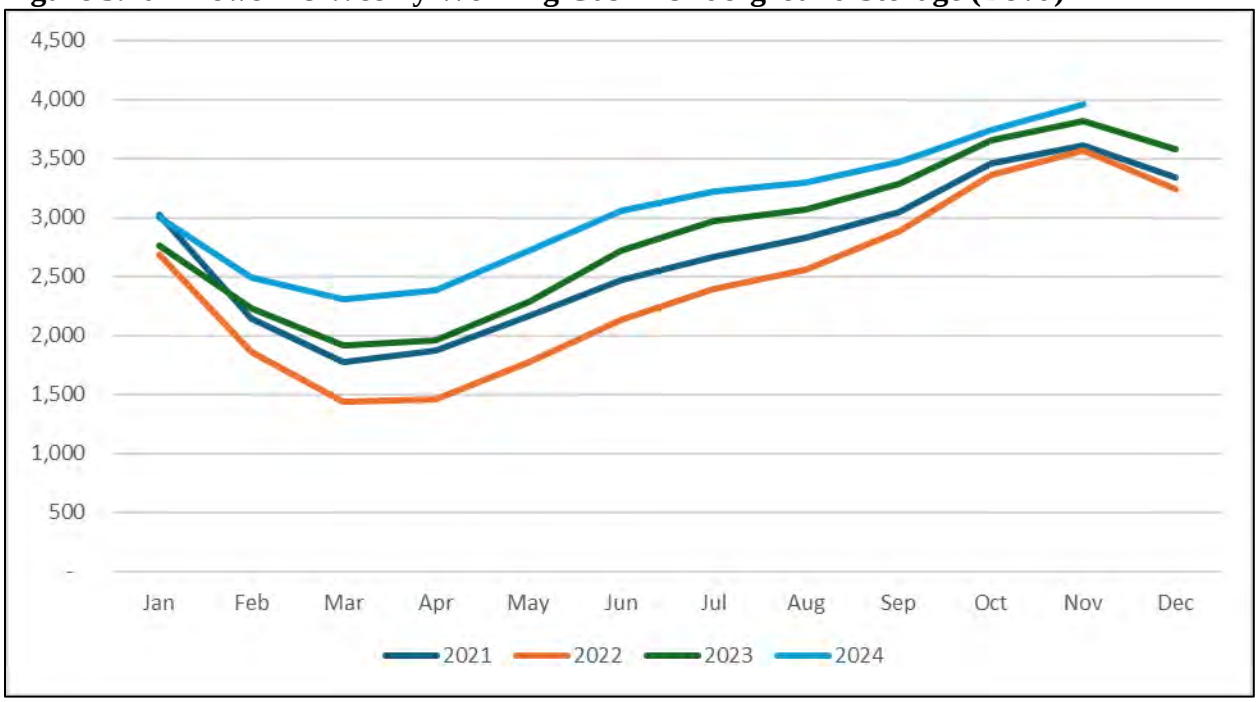
Figure 3.9 – Annual 2022-2023 Change in US Natural Gas Production by Region (bcf/d)



Source: EIA, Siemens PTI

Weather played a critical role in shaping the market. Warmer-than-average winter temperatures in January and February significantly reduced demand for natural gas in residential and commercial heating, particularly in the Midwest and Northeast, where natural gas is a primary heating source for most households. These mild conditions led to the lowest winter consumption levels in seven years and kept storage inventories above the five-year average for much of the year, further pressuring prices downward.

Figure 3.10 – Lower 48 Weekly Working Gas in Underground Storage (Bcf/d)



Source: EIA, Siemens PTI

On the West Coast, natural gas prices were influenced by unique regional factors. Severe winter storms early in the year disrupted supply chains and increased demand for heating in California and surrounding areas, creating temporary price spikes in localized markets. However, as weather conditions stabilized and milder temperatures returned, these pressures eased, and West Coast prices aligned more closely with the broader national trend of declining natural gas costs.

While domestic demand for natural gas remained relatively flat overall, there were notable increases in liquefied natural gas (LNG) exports, which rose by 12%, and pipeline exports, which increased by 9%. These exports helped offset some of the impact of reduced residential and commercial consumption. Despite this, the overall supply-demand balance remained tilted toward oversupply, with storage levels high and production continuing at record rates.

Adding to the dynamics was the gradual recovery of the Freeport LNG facility, which had been offline due to an outage in 2022 and returned to full operation in 2023. While this increased export capacity, it did not significantly alter the broader market trajectory, as domestic production remained the dominant factor. Prices remained under $3.00/MMBtu for most of the year, with May marking the lowest monthly average at $2.19/MMBtu, illustrating how robust supply and subdued demand combined to create one of the least volatile years for natural gas in recent history.

2024 Summary

In 2024, U.S. natural gas prices remained relatively low, with the Henry Hub averaging under $3.00 per MMBtu through November. Production levels, while slightly reduced compared to the previous year, remained robust at an average of 103.3 Bcf/d according to EIA. This marked the first annual production decline since 2020, driven by lower drilling activity because of subdued spot prices. Despite this, overall supply continued to outpace domestic demand, keeping inventories above the five-year average.

In the Permian Basin of western Texas and southeastern New Mexico, natural gas production, primarily as associated gas from oil wells, increased this year alongside rising oil production driven by oil prices, with expanding pipeline takeaway capacity, such as the Matterhorn pipeline, continuing to support higher production levels despite some volatility caused by periodic pipeline maintenance affecting Permian supply

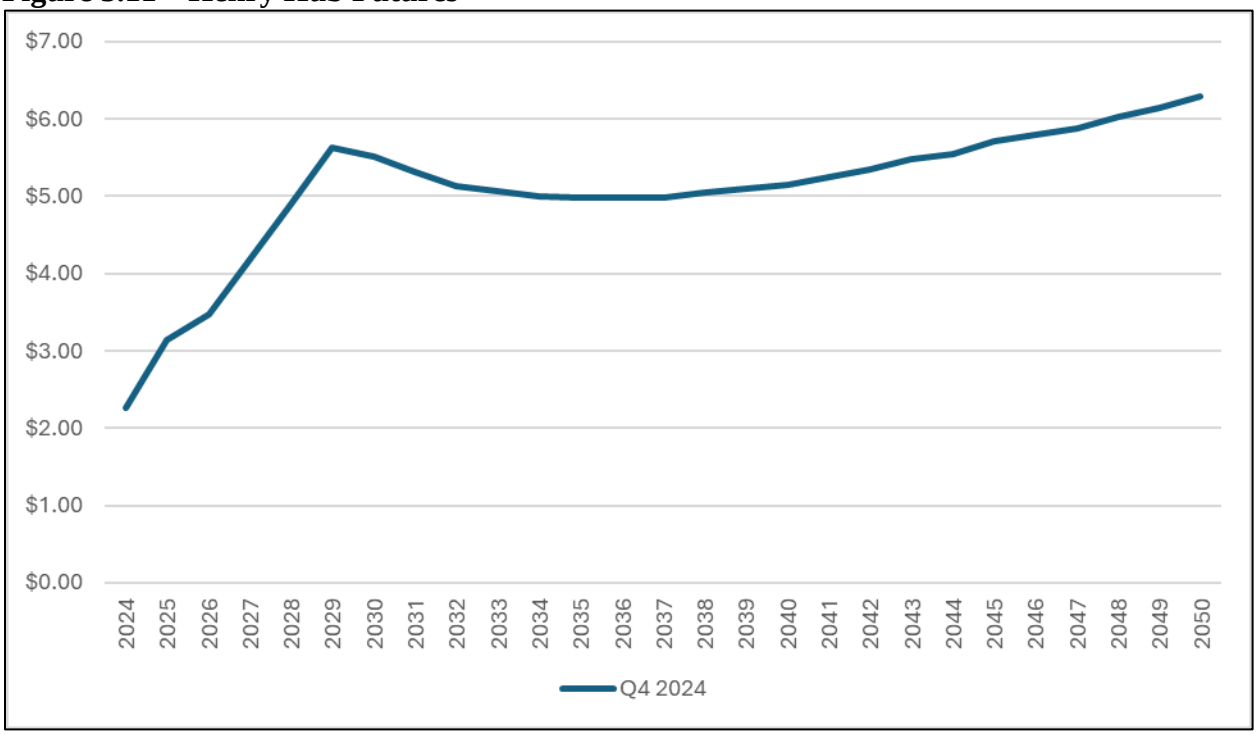
On the demand side, residential and commercial consumption increased due to a colder winter compared to 2023, reversing the trend of reduced heating needs observed in the prior year. LNG exports reached a record 12.1 Bcf/d as global demand for U.S. natural gas grew, particularly in Europe, where efforts to diversify energy sources remained a priority. However, higher exports were offset by stable industrial demand and moderate consumption for power generation, resulting in a balanced domestic market. Regional pricing saw temporary variations, particularly in the West, where localized weather events, including early-season storms, increased heating demand briefly. Despite these regional factors, the national market reflected a stable supply-demand balance with minimal volatility. This relative stability was further supported by the continued high storage levels, maintaining downward pressure on prices throughout the year.

2025-2032 Forward View

As we consider the 2025 to 2030 timeframe, our fundamental forecast for natural gas spot prices at Henry Hub indicates a steady upward trend, with prices expected to average in the mid-$4/MMBtu range in real terms by 2027. Total natural gas demand is projected to reach 122 Bcf/d by 2029, a 13% increase from 2023 levels, driven primarily by rising LNG exports and pipeline deliveries to Mexico. LNG exports are anticipated to double by 2027, as several terminals reach final investment decisions and expand capacity. Similarly, pipeline exports to Mexico are expected to grow significantly, fueled by increased demand for power generation and industrial use.

To meet this growing demand, U.S. natural gas production is expected to expand significantly, particularly from low-cost basins such as the Permian, Eagle Ford, and Haynesville. These regions are well-positioned to serve both domestic and export markets, benefiting from their proximity to demand centers and the development of new takeaway capacity through ongoing pipeline expansion projects. While the market may experience tightness through the middle of the decade due to accelerating LNG export growth, the combination of increased production and strategic infrastructure investments is expected to stabilize supply and support a balanced market by 2032.

Figure 3.11 – Henry Hub Futures



Source: Siemens PTI, GPCM

Conclusion

In summary, the natural gas market is poised for significant growth through the 2025–2030 timeframe, driven by surging export demand and supported by robust production from key basins and expanding infrastructure. While domestic demand shifts modestly, the market's stability will hinge on the alignment of production growth with expanding export capacity. Despite periods of tightness mid-decade, strategic investments and rising supply will position the market for long-term equilibrium, with Henry Hub prices reflecting this balance.

PacifiCorp's Multi-State Process

PacifiCorp is a multi-state utility that provides retail electric service to over 2 million customers across six states. The costs of providing this retail electric service to customers is recovered through retail rates established in regulatory proceedings in each state. To ensure states receive the appropriate allocation of costs and benefits from PacifiCorp's integrated system, the collaborative multi-state process (MSP) has been used to develop an allocation methodology. This collaborative process has led to the development and adoption of PacifiCorp's current inter-jurisdictional cost-allocation method.

The underlying principle of each of the historical inter-jurisdictional cost-allocation methods has been the use of PacifiCorp's system as a single whole. Except for distribution, all states are served from a common portfolio of generation and transmission assets, which enables the company to leverage economies of scale and take advantage of load diversity to plan and operate in a way that results in cost savings for all customers. Recently, state energy policies across the states served by the company have challenged this principle. For example, requirements to remove coal-fired generation from rates in certain states will necessarily result in some states being allocated the

costs and benefits of coal-fired generation while other states are not. Similarly, diverging state polices related to implementation of the Public Utilities Regulatory Policy Act of 1978, retail choice, private generation, and incorporation of societal externalities in resource planning challenge the long-standing practice of planning for a single, integrated system.

In December 2019, PacifiCorp filed the most recent inter-jurisdictional cost-allocation methodology, known as the 2020 PacifiCorp Inter-jurisdictional Allocation Protocol (2020 Protocol). Under the 2020 Protocol, five of PacifiCorp's six retail states would continue sharing all system resources, while Washington, which had previously only recognized resources in PacifiCorp's west Balancing Authority Area, would share in all system transmission and non-emitting resources. Signatories to the 2020 Protocol had been discussing the development of a future allocation methodology that would address all states' energy policy, while maintaining the benefits of PacifiCorp's system.

In 2024, PacifiCorp determined that a negotiated agreement was unlikely given the differences in state energy policies and data limitations for parties to compare alternatives. PacifiCorp will file a new allocation methodology for approval by all six state commissions in 2025 for implementation in 2026 and beyond. PacifiCorp's guiding principles in the development of the new allocation methodology will continue to be:

1. Provide a long-term, durable solution
2. Follow cost-causation principles
3. Minimize rate impacts at implementation
4. Allow for state autonomy for new resource portfolio selection
5. Maintain and optimize system-wide benefits and joint dispatch to the extent possible
6. Enable compliance with state policies
7. Ensure credit-supportive financial outcome
8. Provide the company with a reasonable opportunity to recover its costs

Environmental Regulation

The upcoming administration change featuring Republican control of the House, Senate, and presidency, sets the stage for significant shifts in federal energy policy that could influence PacifiCorp's portfolio selection process used in the development of future IRPs. PacifiCorp recognizes the potential for new legislative and regulatory priorities to impact the energy sector and resource planning. The company actively monitors federal legislative and regulatory developments and participates in rulemaking processes by submitting comments, engaging in hearings, and providing policy assessments to ensure alignment with evolving requirements.

Suggested upcoming legislative priorities under the new administration include changes to the Inflation Reduction Act and a reconciliation bill with energy as a focal point that could directly impact PacifiCorp's existing and potential generation portfolio.

Federal Policy Update

National Electric Vehicle Infrastructure Formula Program

$5 billion FY 2022-2026

The U.S. Department of Transportation's (DOT) Federal Highway Administration (FHWA) NEVI Formula Program will provide funding to states to strategically deploy electric vehicle (EV) charging stations and to establish an interconnected network to facilitate data collection, access, and reliability. Funding is available for up to 80% of eligible project costs, including:

- The acquisition, installation, and network connection of EV charging stations to facilitate data collection, access, and reliability
- Proper operation and maintenance of EV charging stations
- Long-term EV charging station data sharing

On February 6, 2025, the FHWA released a letter suspending approval of state electric vehicle infrastructure deployment plans pending review of the policies underlying the implementation of the NEVI Formula Program. The FHWA aims to have updated draft NEVI Formula Guidance published for public comment in the spring. After the public comment period has closed, FHWA will publish updated final NEVI Formula Guidance that responds to the comments received.

Section 11401 Grants for Charging and Fueling Infrastructure

$2.5 billion for FY 2022 – 2026

Competitive grant program to strategically deploy publicly accessible electric vehicle charging infrastructure and other alternative fueling infrastructure along designated alternative fuel corridors. At least 50 percent of this funding must be used for a community grant program where priority is given to projects that expand access to EV charging and alternative fueling infrastructure within rural areas, low- and moderate-income neighborhoods, and communities with a low ratio of private parking spaces. Opportunity to obtain funding through this grant closed on September 11, 2024.

New Credits and Considerations for Non-emitting Resources – Inflation Reduction Act

The Inflation Reduction Act of 2022 (IRA) is a comprehensive set of clean energy legislation signed into law in August 2022 by President Biden. Substantive details of how the legislation will be implemented are still being fleshed out in the form or regulations and other guidance. The IRA contains newly structured technology-specific and technology-neutral tax credits for electric generating facilities and other clean energy incentives such as credits for Energy Storage Technology, Carbon Capture Use and Sequestration (CCUS), and hydrogen production. Furthermore, the IRA contains incentives that may affect demand, such as tax credits for electric vehicles.

Features of the IRA include:

- The bill directs $437b in spending towards climate and healthcare investments with over $300b dedicated to deficit reduction.
- The bill extends existing and creates new energy investment and production tax credits and institutes a new technology-neutral zero emission generation tax credit in 2025, supplanting the extended generation-specific credits. Eligibility expires upon meeting

economy-wide emissions reduction targets. The bill also establishes a new 15% corporate minimum book tax and a new 1% excise tax on corporate stock buybacks.

- Key Energy Provisions:
  - Extends wind, geothermal, and solar investment and production tax credits at full value through December 31, 2024. Solar projects are newly eligible to apply the production tax credit to energy generated. Additional 10% bonus credits each are available for both locating projects in communities with retired coal operations and meeting certain domestic content requirements; achieving full credit value is also conditioned on meeting wage and apprenticeship requirements.
  - Establishes new tax credits for clean hydrogen, microgrids, electric vehicle purchases, existing nuclear generation, and the domestic manufacture of solar, wind, and battery components. Value and eligibility for existing carbon capture and sequestration credits are also enhanced and expanded.
  - Institutes a new technology-neutral, zero emission generation tax credit in 2025, supplanting the extended technology-specific credits. The technology-neutral credits phase down upon meeting economy-wide emissions reduction targets.

In the 2025 IRP, resources in designated areas are assumed to receive the 10% Energy Community bonus, resulting in a 110% PTC (wind, solar, other energy resources) or 40% ITC (energy storage and peaking resources)

New Credits and Considerations for Customer Resources–Inflation Reduction Act

Beginning January 1, 2023, the Clean Vehicle Credit (CVC) provisions remove manufacturer sales caps, expand the scope of eligible vehicles to include both EVs and FCEVs, and require a traction battery that has at least seven kilowatt-hours (kWh). An available tax credit under the CVC may be limited by the vehicle's MSRP and the buyer's modified adjusted gross income.

Once the Treasury Department issues the critical mineral and battery component guidance, vehicles that meet the critical mineral requirements are eligible for $3,750 tax credit, and vehicles that meet the battery component requirements are eligible for a $3,750 tax credit. Vehicles meeting both the critical mineral and the battery component requirements are eligible for a total tax credit of $7,500.

The IRA also extends the federal Investment Tax Credit (ITC) for small scale solar systems through 2034 and expands the credit to include standalone energy storage systems as well. Since the passage of the IRA, the ITC has been extended beyond its original expiration date for ten years. For facilities beginning construction before January 1, 2025, the bill will extend the ITC for up to 30 percent of the cost of installed equipment for ten years and will then step down to 26 percent in 2033 and 22 percent in 2034. For projects beginning construction after 2019 that are placed in service before January 1, 2022, the ITC is set at 26 percent. In addition to the new federal ITC schedule for generating facilities, the updated ITC includes credits for standalone energy storage with a capacity of at least 3 kWh for residential customers and 5 kWh for non-residential customers.

The IRA funds multiple programs and tax incentives to improve the energy efficiency for residential and non-residential buildings and equipment. For non-residential buildings, the IRA provides tax deductions of $0.50–5.00 per square foot (/sf) of floor area to owners of new and

improved energy-saving commercial buildings depending on the percentage of energy savings and whether the contractor pays prevailing wages. Even larger broad greenhouse gas emission reduction programs under the IRA could be used to reduce emissions from commercial buildings. The IRA also provides more than $25 billion for programs and tax incentives to improve the energy efficiency of existing and new homes. In addition to program funding, the IRA enhances the 25C Energy Efficient Home Improvement Credit. This long-standing federal tax credit applies to home energy improvements such as insulation, windows, heat pumps, and furnaces. Starting in 2023, IRA increases the credit to 30% of cost, with an annual cap of $1,200 along with smaller limits for most items, but it also allows up to $2,000 for a heat pump (in 2022 the credit is under the old rules, with lower amounts and a lifetime cap of $500).

New Source Performance Standards for Carbon Emissions from New and Existing Sources – Clean Air Act § 111(b) and (d)

New Source Performance Standards are established under the Clean Air Act for certain industrial sources of emissions determined to endanger public health and welfare, including thermal electric generating units. After two previous iterations, in April 2024, EPA finalized new rules addressing greenhouse gas emissions from new and reconstructed natural gas-fueled combustion turbines (Clean Air Act Section 111(b) rule) and existing coal- and gas- or oil-fueled steam units (Clean Air Act Section 111(d) rule).

For new combustion turbines, the final rule establishes three subcategories based on operating intensity as measured by capacity factor.

1. Base load turbines (operating above 40% of maximum annual capacity factor) must initially meet a standard reflective of an efficient combined cycle design and achieve 90% carbon capture by January 1, 2032.
2. Intermediate load turbines (operating between 20% and 40% of capacity factor) must meet a standard reflective of an efficient simple cycle design.
3. Low load turbines (operating below 20% capacity factor) must meet a standard based on using low-emitting fuels.

For existing coal-fired electric generating units (EGUs), the final rule subcategorizes plants based on the units intended operational timeline.

1. Long-term units (operating beyond January 1, 2039) must meet emission limits based on 90% carbon capture and storage (CCS) by January 1, 2032.
2. Medium-term units (retiring by January 1, 2039) must meet limits by January 1, 2030, using 40% natural gas co-firing.
3. Near-term units (closing before January 1, 2032) have no emission reduction obligations.

For existing gas- or oil-fueled steam units, the final rule subcategories units based on capacity factor.

1. Base load units (annual capacity factor greater than or equal to 45%) must maintain routine operations and maintenance, with no increase in emission rate (1,400 lb/MWh)
2. Intermediate load units (annual capacity factor between 8% and 45%) must maintain routine operations and maintenance, with no increase in emission rate (1,600 lb/MWh)
3. Low load units (annual capacity factor less than 8%) must meet a standard based on using low-emitting fuels.

States are required to submit implementation plans within two years of the rule's publication. These plans must show meaningful engagement with stakeholders, including affected communities and reliability authorities. States also have flexibility to consider factors like Remaining Useful Life, allow for emissions trading and averaging, and provide one-year compliance extensions for delays beyond an operator's control.

The rule has been challenged by multiple parties and is currently awaiting a decision from the D.C. Circuit Court of Appeals.

Credit for Carbon Oxide Sequestration – Internal Revenue Service § 45Q

In 2008, the Internal Revenue Service issued a tax credit for carbon oxide sequestration under section 45Q to incentivize carbon capture and sequestration (CCS) investments. The tax credit is computed per metric ton (tonne) of qualified carbon oxide captured and sequestered.[7] Carbon oxide can either be permanently disposed of in secure geological storage or the carbon oxide can be utilized – typically as a tertiary injectant in enhanced oil recovery (EOR).

The Bipartisan Budget Act of 2018 reformed 45Q for carbon capture equipment that is placed in service on or after February 9, 2018, increasing the credit amount from $10/tonne to $35/tonne for utilization and from $20/tonne to $50/tonne for storage.[8] This Act also removed the limit on the amount of tax credits that could be awarded for CCS, and, instead, requires a minimum amount of carbon oxide to be capture annually (500,000 tonnes per year for an electric generating facility) and is available for 12 years from the date the carbon capture equipment is originally placed into service. The Consolidated Appropriations Act of 2021 extended the date construction must begin to receive the tax credits by two years, from January 1, 2024, to January 1, 2026.

The Inflation Reduction Act made considerable changes to the 45Q tax credit in 2022. The tax credit amount increased to $60/tonne (use) and $85/tonne (storage), the construction window was extended to January 1, 2033, the minimum capture thresholds were lowered (18,750 tonnes per year for electric generating facilities) and the Act now requires 75% of a generating units CO_2 production to be captured, among other requirements.

Clean Air Act Criteria Pollutants – National Ambient Air Quality Standards

The Clean Air Act requires EPA to set National Ambient Air Quality Standards (NAAQS) for six criteria pollutants that have the potential of harming human health or the environment. The NAAQS are rigorously vetted by the scientific community, industry, public interest groups, and the public, and establish the maximum allowable concentration allowed for each "criteria" pollutant in outdoor air. The six pollutants are carbon monoxide, lead, ground-level ozone, nitrogen dioxide (NOX), particulate matter (PM), and sulfur dioxide (SO_2). The primary standards are set at a level that protects public health with an adequate margin of safety. The secondary standards are set to protect the public welfare from adverse effects including those related to effects on soils, water, crops, vegetation, anthropogenic materials, among other impacts. If an area is determined to be out of compliance with an established NAAQS standard, the state is required to develop a state implementation plan (SIP) to bring that area into compliance, and that plan must be approved by

[7] Before February 9, 2018, the tax credit was strictly for CO_2.
[8] The tax credit reaches $35/tonne and $50/tonne in 2026.

EPA. The plan is developed so that once implemented, the NAAQS for the pollutant of concern will be achieved.

Ozone NAAQS

In October 2015, EPA issued a final rule modifying both the primary and secondary 8-hour ozone from 75 parts per billion (ppb) to 70 ppb. In addition to meeting the ozone NAAQS for areas within a state, states must also conduct an analysis of cross-state air pollution to determine whether emissions from the state have a significant impact on neighboring states attaining or maintaining the ozone NAAQS. On April 6, 2022, EPA proposed its "Good Neighbor Rule" for the 2015 ozone NAAQS (the "Ozone Transport Rule" or "OTR"), which proposed a federal implementation plan (FIP) to eliminate interstate transport of ozone precursors from states that EPA identified as significantly contributing to downwind nonattainment or interfering with maintenance of the 2015 ozone NAAQS in other states. The proposed rule covered 26 states, including four western states included in the cross-state program for the first time – Wyoming, Utah, Nevada and California. Specifically, EPA proposed in that action to implement emissions reductions by requiring some sources within these states to participate in revised provisions of the Cross-State Air Pollution Rule (CSAPR). EPA applied the interstate transport framework developed in CSAPR, the CSAPR Update, the Revised CSAPR Update, and other previous ozone transport rules to propose to further limit NOx emissions from electric generating unit (EGU) sources within the borders of 25 states during the ozone season and to limit ozone season NOx emissions from non-EGU sources in 23 states to reduce interstate ozone transport.

On February 13, 2023, EPA finalized disapproval of interstate ozone transport SIP submissions for the 2015 8-hour ozone NAAQS for multiple states and issued a partial disapproval for two additional states. This included the SIP for Wyoming. In the same action, EPA deferred final action on its proposed disapproval for Wyoming. For both Utah and Wyoming, the agency determined that, among other failings, the states should have used a 1% threshold instead of the one ppb threshold despite EPA previously recognizing, in an August 2018 memorandum, that state may establish an alternative contribution threshold of 1 ppb. States, like Utah, for which EPA issued disapproval actions of their interstate ozone transport SIPs were required to comply with the interstate ozone transport FIP for the 2015 ozone standard upon finalization of that action on March 2023. Due to EPA's delayed final action on Wyoming's SIP submission, Wyoming was not required to comply with the final interstate ozone transport FIP for the 2015 8-hour ozone NAAQS.

Numerous states and industries, including PacifiCorp, challenged certain provisions of the ozone interstate transport SIP disapprovals and FIP for the 2015 ozone standard. The state of Utah and PacifiCorp filed petitions and motions for stay of EPA's denial of the Utah SIP with EPA and the U.S. Tenth Circuit Court of Appeals (Tenth Circuit), and the motion for stay was granted by the Tenth Circuit on July 27, 2023. The stay will remain in place while the case is litigated, or until further order of the court. The court held that the agency may not enforce the interstate transport FIP for the 2015 ozone NAAQS while the stay remains in place. In granting the stay, the court indicated that PacifiCorp and the other petitioners are likely to succeed on the merits. The EPA also issued several interim final rules stating that the federal rule will not take effect in states in which the SIP disapprovals have been stayed.

The EPA finalized approval of Wyoming's interstate ozone transport SIP on December 19, 2023. Given the approval of the Wyoming SIP, PacifiCorp facilities in Wyoming are not subject to the interstate ozone transport FIP. Given the court stay of EPA's disapproval of Utah's SIP, PacifiCorp

was not subject to the interstate ozone FIP requirements for the 2015 ozone NAAQS during the 2023 ozone season. The Utah ozone case was transferred to the D.C. Circuit on February 16, 2024, for adjudication on the merits, leaving the stay in place. Requirements for the 2024 ozone season and beyond will depend on the outcome of the litigation.

In addition to litigation over SIP disapprovals, numerous appeals of, and motions to stay, the interstate ozone FIP were filed in four different circuit courts. On September 25, 2023, the D.C. Circuit denied the motion to stay the interstate ozone transport FIP for the 2015 ozone standard that was filed by several state and industry parties. The states of Ohio, Indiana and West Virginia filed a request for an emergency stay of the interstate ozone transport FIP with the U.S. Supreme Court on October 13, 2023. Several industry groups representing utilities as well as pipeline, paper, cement, and other industries affected by the rule, filed supportive requests for a stay on the same day. The U.S. Supreme Court granted a stay of the FIP on June 27, 2024. Accordingly, states are not required to comply with the ozone transport FIP pending the stay.

On December 9, 2024, EPA signed a final rule to reclassify the Northern Wasatch front, which includes Salt Lake County, from moderate to serious nonattainment for the 2015 Ozone NAAQS. PacifiCorp's Gadsby facility is in the Northern Wasatch Front area and was previously identified as a major source subject to Utah's moderate nonattainment area SIP for Ozone. In anticipation of EPA's decision, the Utah Department of Environmental Quality (DEQ) requested that PacifiCorp submit a reasonably available control technology (RACT) analysis to the Utah DEQ's Division of Air Quality. PacifiCorp submitted the RACT analysis on January 9, 2024, and followed the top down RACT analysis process for each nitrogen oxide and volatile organic carbon emission source at the at the Gadsby plant. Plant emissions from 2017 were utilized to prepare cost effectiveness analyses for add-on controls; these analyses demonstrated that no additional controls are cost effective at this time.

Particulate Matter NAAQS

On October 17, 2006, EPA revised the level of the 24-hour $PM_{2.5}$ NAAQS from 65 micrograms per cubic ($\mu g/m^3$) meter to 35 $\mu g/m^3$. On May 10, 2017, the EPA Administrator signed a final action to reclassify the Salt Lake City and Provo $PM_{2.5}$ nonattainment areas from moderate to serious for the 2006 24-hour $PM_{2.5}$ NAAQS. PacifiCorp's Lake Side and Gadsby facilities were subject to major source requirements due to their emissions of PM2.5. On April 27, 2017, PacifiCorp submitted a Best Available Control Technology (BACT) determination for Lake Side and Gadsby to the Utah Division of Air Quality for review. On January 2, 2019, the Utah Air Quality Board adopted source specific emission limits and operating practices for the Lake Side and Gadsby facilities in the SIP.

On November 17, 2020, EPA finalized redesignation of the Salt Lake City and Provo nonattainment areas to attainment for the 2006 24-hour $PM_{2.5}$ NAAQS. On April 6, 2021, EPA reopened the comment period after adding supplemental information to the proposal. Re-designation to attainment would have no effect on current emissions and operating limits for the Lake Side and Gadsby facilities.

On March 6, 2024, EPA revised the primary annual $PM_{2.5}$ NAAQS from 12.0 $\mu g/m^3$ to 9.0 $\mu g/m^3$. EPA has not yet designated areas as attainment, nonattainment, unclassifiable/attainment, or unclassifiable under this new standard.

Regional Haze

Clean Air Act (CAA) Section 169A includes a program for protecting visibility in the nation's mandatory Class I Federal areas, which include national parks and wilderness areas. The CAA directs EPA to promulgate regulations to assure reasonable progress toward meeting the goal of protecting visibility. In 1990, CAA section 169B was added to further address visibility impairment, specifically, impairment from regional haze. EPA promulgated the Regional Haze Rule in 1999, which requires states to develop and implement plans to improve visibility, by 2064, in certain national park and wilderness areas. Many of these areas are in the western United States where PacifiCorp owns and operates several coal-fired generating units (Utah, Wyoming, Colorado, and Montana). The states are required to update their regional haze rule plans generally every ten years, with second planning period revisions due in August of 2023. Litigation over the first planning period requirements for both Utah and Wyoming are mostly concluded.

On July 6, 2005, EPA published final amendments to its regional haze rule to require emission controls known as Best Available Retrofit Technology (BART) for industrial facilities meeting certain regulatory criteria with emissions that have the potential to affect visibility. The regulated pollutants include PM, NOx, SO_2, certain VOCs, and ammonia. The 2005 amendments included BART guidelines for states to use in determining which facilities must install controls and presumptive controls for certain sources subject to BART. States were given until December 2007 to develop their implementation plans, in which states were responsible for identifying the facilities that would have to reduce emissions under BART guidelines, as well as establishing BART emissions limits for those facilities.

On August 20, 2019, EPA issued a final guidance document on the technical aspects of developing regional haze SIPs for the second implementation period of the regional haze program. EPA issued additional guidance on July 8, 2021, that discusses source selection, characterization of factors for emission control measures, decisions on what control measures are necessary to make reasonable progress, consideration of visibility in making control determinations, and the consideration of five additional factors, among other topics.

Utah Regional Haze

In May 2011, the state of Utah submitted to EPA a regional haze SIP for the first planning period requiring the installation of SO_2, NOx and PM controls on Hunter Units 1 and 2 and Huntington Units 1 and 2. In December 2012, EPA approved the SO_2 portion of the Utah regional haze SIP and disapproved the NOx and PM portions for Hunter Units 1 and 2 and Huntington Units 1 and 2. EPA's approval of the SO_2 SIP was appealed by environmental groups to the Tenth Circuit. In addition, PacifiCorp and the state of Utah appealed EPA's disapproval of the SIP on the basis that the NOx and PM BART determinations for the sources did not comply with the Regional Haze rules. PacifiCorp and the state's appeals were dismissed as was the appeal filed by environmental groups in the Tenth Circuit. In June 2015, Utah submitted a revised SIP to EPA for approval which included an alternative BART NOx analysis incorporating a requirement for PacifiCorp to retire Carbon Units 1 and 2 and crediting NOx emission reductions from Hunter Units 1, 2, and 3 and Huntington Units 1 and 2. On July 5, 2016, EPA published a final rule to partially approve and partially disapprove Utah's regional haze SIP and propose a FIP. The FIP established NOx emission limitations on Hunter Units 1 and 2 and Huntington Units 1 and 2 that are reflective of Selective Catalytic Reduction (SCR) and Low-NOx Burners (LNB) and Separated Overfire Air (SOFA). On September 2, 2016, the state of Utah and PacifiCorp filed petitions for administrative

and judicial review of EPA's final rule, followed by a motion to stay the effective date of the final rule.

On June 30, 2017, Utah and PacifiCorp provided new information to EPA, again requesting reconsideration. EPA responded on July 14, 2017, indicating its intent to reconsider its FIP. EPA also filed a motion with the Tenth Circuit to stay EPA's FIP and hold the litigation in abeyance pending the rule's reconsideration. On September 11, 2017, the Tenth Circuit granted the petition for stay and the request for abatement. The compliance deadline of the FIP as well as the litigation were stayed pending EPA's reconsideration, and EPA was required to file periodic status reports with the court.

Utah and PacifiCorp worked with EPA to develop a revised Utah regional haze SIP, based on new CAMx modeling. The Utah Air Quality Board approved the revised SIP on June 24, 2019, and the SIP revision was submitted to EPA for review on July 3, 2019. On December 3, 2019, Utah submitted a supplement to EPA that would require reporting of all deviations from compliance with the applicable requirements under BART and the BART Alternative, including the emission limits for Hunter and Huntington.

On January 22, 2020, EPA published its proposed approval of the Utah SIP revision and withdrawal of the FIP requirements that would have required emissions limitations for the Hunter and Huntington plants equivalent to SCR plus upgraded combustion controls (LNB/SOFA). EPA subsequently finalized approval of the SIP and withdrawal of the FIP as proposed on November 27, 2020. On January 11, 2021, the Tenth Circuit granted Utah, PacifiCorp and EPA's motion to dismiss the Utah regional haze petitions.

Environmental groups filed a petition for review in the Tenth Circuit on January 19, 2021, objecting to EPA's approval of Utah's regional haze SIP for the first planning period. After holding the case in abeyance at EPA's request, the Tenth Circuit lifted the abeyance and granted PacifiCorp and Hunter co-owners and Utah's pending motions to intervene. On August 14, 2023, the Tenth Circuit determined EPA properly approved the Utah regional haze SIP for the first planning period and denied environmental groups' petition.

On April 21, 2020, PacifiCorp submitted a Regional Haze Reasonable Progress Analysis for the second planning period to the Utah Department of Environmental Quality for PacifiCorp's Huntington and Hunter plants. The analysis was requested by the state as part of its second planning period SIP development process. PacifiCorp's analysis included a proposal to implement reasonable progress emission limits for NOx and SO_2 at the Hunter and Huntington units to meet second planning period requirements.

The Utah Air Quality Division proposed, and the Utah Air Quality Board approved, final adoption of a SIP for the regional haze second planning period on July 6, 2022, and submitted the SIP to EPA on August 2, 2022. The SIP differs from PacifiCorp's Reasonable Progress Analysis and requires updated mass-based NOx limits. The SIP also concluded that existing SO_2 limits in Hunter and Huntington's title V permits were necessary to make reasonable progress but required no further SO_2 emission limits for the plants.

On December 2, 2024, EPA finalized a final partial approval and partial disapproval for Utah's regional haze state implementation plan for the second planning period without simultaneously

finalizing a federal implementation plan. Specifically, EPA disapproved the long-term strategy, reasonable further progress goals, and federal land management (FLM) consultation components of the SIP. EPA's disapproval of Utah's long-term strategy is based, in part, on EPA's rejection of Utah's finding that installation of SCR or other physical NOx pollution controls for Hunter and Huntington is not necessary to achieve reasonable progress. There are no new compliance obligations for PacifiCorp at this time, as the disapprovals did not include a simultaneously finalized FIP. PacifiCorp filed a petition for reconsideration on EPA's disapproval action on January 30, 2025, and filed a petition for review in the Tenth Circuit the next day.

Wyoming Regional Haze

On January 30, 2014, EPA published a final rule partially approving and partially disapproving the Wyoming regional haze SIP for the first planning period and promulgating a FIP to address the deficiencies EPA found in the Wyoming SIP submission. As a result of the 2014 final rule and FIP, the following controls were required at PacifiCorp facilities for the regional haze first planning period:

- Naughton Units 1 and 2: LNB/OFA, with an emission limit of 0.28 lbs/MMBtu for each unit
- Naughton Unit 3 by December 31, 2014: SCR + LNB/SOFA, 0.07 lb/MMBtu (30-day rolling average).
- Jim Bridger Unit 3 by December 31, 2015: SCR, with an emission limit of 0.07 lb/MMBtu (30-day rolling average)
- Jim Bridger Unit 4 by December 31, 2016: SCR, with an emission limit of 0.07 lb/MMBtu (30-day rolling average)
- Jim Bridger Unit 2 by December 31, 2021: SCR, with an emission limit of 0.07 lb/MMBtu (30-day rolling average) and NOx emission limit of 0.26 lb/MMBtu by March 4, 2015
- Jim Bridger Unit 1 by December 31, 2022: SCR, with an emission limit of 0.07 lb/MMBtu (30-day rolling average) and NOx emission limit of 0.26 lb/MMBtu by March 3, 2015
- Dave Johnston Unit 3: Either a commitment to retire by 2027 and LNB/OFA, with an emission limit of 0.28 lbs/ MMBtu (30-day rolling average) or SCR + LNB/OFA, with an emission limit of 0.07 lbs/ MMBtu (30-day rolling average)
  Wyodak Unit 1: SCR+ LNB/SOFA, with an emission limit of 0.07 lb/ MMBtu (30-day rolling average)

Naughton – In its 2014 rule, EPA approved Wyoming's determination that NOx BART for Units 1 and 2 was LNB and OFA. While EPA approved Wyoming's NOx BART determination of SCR and LNB/OFA, with an emission limit of 0.07 lb/MMBtu (30-day rolling average) for Naughton Unit 3, EPA stated that it would approve limitations that reflect the conversion of Unit 3 to natural gas once Wyoming submitted the requisite SIP revision. On November 28, 2017, Wyoming submitted to EPA a source-specific revision to its regional haze SIP for the first planning period for the Naughton Unit 3 conversion. On March 7, 2017, Wyoming issued PacifiCorp a permit for Unit 3's conversion to natural gas, which allowed Unit 3 to operate on coal through January 30, 2019. PacifiCorp ceased coal operation on Unit 3 on January 30, 2019, as required by the permit. EPA's final rule approving Wyoming's SIP revision for Naughton Unit 3's gas conversion was published in the Federal Register on March 21, 2019, with an effective date of April 22, 2019. Naughton Unit 3 currently operates on natural gas. Environmental groups petitioned EPA's approval of LNB/OFA as NOx BART for Units 1 and 2 in the Tenth Circuit. On August 15, 2023, the court determined EPA properly approved Wyoming's Naughton determination and denied

environmental groups' petition.

Jim Bridger – In its 2014 rule, EPA approved Wyoming's determination that Jim Bridger Units 1 and 2 meet an emission limit of 0.07 lb/MMBtu (30-day rolling average) by 2022 and 2021, respectively. EPA also approved Wyoming's NOx BART determination that required Jim Bridger Units 1 and 2 to meet a NOx emission limit of 0.26 lb/MMBtu (30-day rolling average) by March 4, 2019. For Jim Bridger Units 3 and 4, EPA approved Wyoming's determination that the appropriate level of NO_X control for Units 3 and 4 for purposes of reasonable progress is the SCR-based emission limit in the SIP of 0.07 lb/MMBtu, with compliance dates of December 31, 2015, for Unit 3 and December 31, 2016, for Unit 4. Accordingly, SCR was installed on Jim Bridger Units 3 and 4 by the dates required by the Wyoming SIP. On February 5, 2019, PacifiCorp submitted to Wyoming an air permit application for monthly average plant-wide NOx and SO_2 emission limits, in addition to an annual combined NOx and SO_2 limit, on all four Jim Bridger boilers in lieu of the requirement to install SCR on Units 1 and 2. PacifiCorp proposed that the plantwide limits were more cost effective while leading to better modeled visibility than SCR installations on Units 1 and 2. Wyoming submitted a regional haze SIP revision to the EPA on May 14, 2020, that incorporated PacifiCorp's proposed emission limits in lieu of the requirement to install SCR on Jim Bridger Units 1 and 2. While EPA communicated that it would issue a proposed approval of Wyoming's Jim Bridger SIP, the proposal was not issued before the administration change in 2021.

When EPA failed to issue a determination by the statutory deadline in November 2021, the Governor of Wyoming issued a temporary emergency order on December 27, 2021, using authority granted by the Clean Air Act, suspending the existing SIP requirement for Jim Bridger Unit 2 to install SCR by December 31, 2021. The suspension was issued for four months due to the EPA's failure to act on the SIP revision submitted by Wyoming in 2020. EPA published a proposed disapproval of the Jim Bridger SIP revision on January 18, 2022. However, PacifiCorp negotiated a consent decree with Wyoming and an administrative consent order with EPA and the disapproval was not finalized. Under the Wyoming consent decree and EPA administrative consent order, PacifiCorp is required to comply with a compliance plan that allows continued operation of Jim Bridger Units 1 and 2 under the emission limits established by Wyoming in 2020 until they are converted to natural gas in 2024. The consent decree committed Wyoming to processing a SIP revision requiring the conversion and imposing post-conversion emission limits.

On December 30, 2022, Wyoming submitted to EPA for approval a revised regional haze SIP requiring natural gas conversion of Jim Bridger Units 1 and 2. The SIP conversion replaces the previous requirement for SCR at the units. Wyoming issued to PacifiCorp an air permit for the natural gas conversion of Jim Bridger Units 1 and 2 on December 28, 2022. PacifiCorp completed the conversion. On April 10, 2024, EPA proposed to approve Wyoming's December 2022 SIP revision for Jim Bridger Units 1 and 2. The SIP includes enforceable emissions and heat input limits at Jim Bridger Units 1 and 2, consistent with the conversion of those units to natural gas. EPA accepted comments on the proposed approval through May 10, 2024, but has not yet finalized the approval.

Dave Johnston – EPA's January 20, 2014, FIP action required either the installation of SCR on Dave Johnston Unit 3 or that the unit retire by the end of 2027. PacifiCorp opted not to install SCR. EPA approved Wyoming's NOx BART determination for Dave Johnston Unit 4 of an emission limit of 0.15 lb/MMBtu (30-day rolling average). EPA also approved Wyoming's NOx

reasonable progress determinations for Dave Johnston Units 1 and 2 that no controls were necessary.

Wyodak – EPA's January 20, 2014, FIP action determined SCR + LNB/SOFA to be NOx BACT. PacifiCorp and Wyoming petitioned EPA's FIP that would require SCR at Wyodak in the Tenth Circuit. On September 9, 2014, the Tenth Circuit stayed the NOx emission limits for Wyodak Unit 1 in the regional haze FIP pending court resolution of the petition. PacifiCorp subsequently submitted a request for reconsideration to EPA and engaged in a settlement process with EPA and Wyoming. EPA, Wyoming and PacifiCorp signed a Settlement Agreement for Wyodak on December 16, 2020. On January 4, 2021, EPA published the proposed settlement agreement in the Federal Register, requesting public comment. PacifiCorp submitted comments to EPA on March 5, 2021, in support of the Wyodak proposed settlement agreement. However, EPA did not proceed with final approval of the proposed settlement agreement but rather re-engaged with Wyoming and PacifiCorp in mediation through the Tenth Circuit. Litigation for the Wyodak case challenging EPA's denial of the Wyoming SIP and finalization of a FIP recommenced when the mediation process was not successful. On August 15, 2023, the Tenth Circuit found EPA's disapproval of Wyoming's SIP for Wyodak unlawful and remanded the SIP to EPA for further review in accordance with the requirements of the Clean Air Act.

Wyoming Regional Haze Second Planning Period – On March 31, 2020, PacifiCorp submitted a four-factor reasonable progress analysis to Wyoming which analyzed PacifiCorp's Naughton, Jim Bridger, Dave Johnston, and Wyodak plants. Wyoming incorporated the four-factor analyses in its SIP for the regional haze second planning period. Wyoming determined that emission limits and planned unit retirements met the reasonable progress goals for Regional Haze. Wyoming submitted the state's regional haze SIP for the second planning period to EPA on August 10, 2022.

On December 2, 2024, EPA finalized partial approval and partial disapproval of Wyoming's regional haze SIP for the second planning period. Specifically, EPA disapproved the long-term strategy, reasonable further progress goals, and federal land management consultation components of the state plan. EPA's disapproval of Wyoming's long-term strategy is based in part on the state's decision to forego a full four-factor analysis for units at Jim Bridger, Naughton, Dave Johnston, and Wyodak. There are no new compliance obligations for PacifiCorp at this time, as the disapproval action did not include a simultaneously finalized FIP. On January 30, 2025, the state of Wyoming submitted an "open letter" to EPA stating its concerns about the agency's disapproval of the regional haze second planning period plan for the state. On January 31, 2025, the state also filed a petition for review in the Tenth Circuit. PacifiCorp filed a petition for reconsideration with the agency on January 30, 2025, and petition for review in the Tenth Circuit the next day.

Colorado Regional Haze

Craig- The Colorado regional haze SIP for the first planning period established SO_2 BART emission limits on Craig Units 1 and 2 of 0.11 lb/MMBtu (30-day rolling average). Colorado incorporated NOx emission limits of 0.28 lb/MMBtu (30-day rolling average) for Craig Unit 1 and 0.08 lb/MMBtu (30-day rolling average) for Craig Unit 2 in the SIP. Although the state determined that SNCR was reasonable for BART for both Units 1 and 2, Tri-State and Colorado agreed to a NOx emission control plan for Unit 2 that reflected SCR and was therefore more stringent than the BART determination. Colorado determined that the PM BART emission limit is 0.03 lb/MMBtu (30-day rolling average) at Craig Units 1 and 2, which could be met through the operation of the existing fabric filter baghouses.

Hayden- In its regional haze SIP for the first planning period, Colorado determined that the SO_2 BART emission limit for Hayden Unit 1 is 0.13 lb/MMBtu (30-day rolling average) and for Unit 2 is 0.13 lb/MMBtu (30-day rolling average). These limits are met with the operation of the existing controls. For NOx, Colorado determined that the NO_X BART emission limit for Hayden Unit 1 is 0.08 lb/MMBtu (30-day rolling average) and for Unit 2 is 0.07 lb/MMBtu (30-day rolling average). These BART emission limits could be met through the installation and operation of SCR. Colorado determined that the PM BART emission limit is 0.03 lb/MMBtu (30-day rolling average) for Hayden Unit 1 and Unit 2. These PM emission limits can be met through the operation of the current fabric filter baghouses.

EPA found Colorado's determinations for the Craig and Hayden units to be approvable and finalized approval of the Colorado regional haze SIP for the first planning period on December 31, 2012. Environmental groups appealed EPA's action in February 2013, and PacifiCorp intervened in support of EPA. In July 2014, parties to the litigation other than PacifiCorp entered into a settlement agreement that requires installation of SCR equipment, with a NOx BART emission limit for Craig Unit 1 is 0.07 lb/MMBtu, calculated on a 30 boiler-operating-day rolling average at Craig Unit 1 by August 31, 2021, 2021.

On May 26, 2017, Colorado submitted a SIP amendment to EPA that reflected further agreement between the owners of Craig Unit 1, state and federal agencies, and parties to previous settlements The revised SIP required Craig Unit 1 to meet an annual NO_X emission limit of 4,065 tons per year by December 31, 2019. The SIP revision also required the unit to either convert to natural gas by August 31, 2023, and if converting to natural gas, comply with a NO_X emission limit of 0.07 lb/MMBtu (30-day rolling average) beginning August 31, 2021, or shut down by December 31, 2025. EPA approved the SIP on July 5, 2018.

Colorado Regional Haze Second Planning Period – Colorado's regional haze SIP for the second planning period was adopted in phases in 2020 and 2021 by the Colorado Air Quality Control Commission. The SIP includes retirements of Craig Units 1 and 2 by 2025 and 2028, respectively, and Hayden Units 1 and 2 by 2028 and 2027, respectively. Colorado submitted its second planning period regional haze SIP to EPA on March 22, 2021. However, EPA has not yet acted on the Colorado regional haze SIP for the second planning period. The Colorado SIP is part of the deadline suit filed by environmental groups in the federal D.C. District Court.

Mercury and Hazardous Air Pollutants

The Mercury and Air Toxics Standards (MATS) became effective April 16, 2012. The MATS rule required that coal- and oil-fired facilities achieve emission standards for mercury, acid gas hazardous air pollutants (HAPs), non-mercury HAP metals, and organic HAPs. Existing sources were required to comply with the new standards by April 16, 2015. However, individual sources may have been granted up to one additional year, at the discretion of the Title V permitting authority, to complete installation of controls. By April 2015, PacifiCorp had taken the required actions to comply with MATS across its generation facilities. On April 25, 2016, in response to a Supreme Court decision requiring consideration of costs, EPA published a Supplemental Finding that determined that it is appropriate and necessary to regulate coal- and oil-fired EGUs under the Clean Air Act.

On February 7, 2019, EPA published a reconsideration of the Supplemental Finding in which it proposed to find that it is not appropriate and necessary to regulate HAPs, reversing the Agency's

prior determination. On May 22, 2020, EPA published a reconsideration of its 2016 supplemental finding. In the reconsideration action, EPA determined that it is not appropriate and necessary to regulate HAP emissions from coal- and oil-fired EGUs. The rule was effective May 22, 2020. Several petitions for review were filed in the D.C. Circuit by parties challenging and supporting EPA's decision to rescind the appropriate and necessary finding. The court granted EPA's motion to hold the cases in abeyance while the agency reviewed the 2020 repeal. On March 6, 2023, EPA finalized a rule rescinding the 2020 revocation of the appropriate and necessary finding. The rule therefore reinstated the finding. Because PacifiCorp plants are in compliance with the MATS standards, the reinstatement of the finding has immediate impact on PacifiCorp's operations.

On April 25, 2024, EPA finalized revisions to the MATS rule following the agency's review of the 2020 Residual Risk and Technology Review. The final rule, effective July 8, 2024, tightens the standard for emissions of mercury from existing lignite-fired units by 70 percent and sets a more stringent standard for emissions of filterable particulate matter from existing coal-fired power plants. The rule also requires that continuous emissions monitoring be used to demonstrate compliance with the filterable PM standard.

Coal Combustion Residuals

On April 17, 2015, EPA finalized a rule to regulate the management and disposal of coal combustion residuals (CCR) under the Resource Conservation and Recovery Act (RCRA). The final rule became effective October 19, 2015. The rule establishes minimum nationwide standards for new and existing CCR landfills and surface impoundments as well as all lateral expansions consistent of location restrictions, design and operating criteria, groundwater monitoring and corrective action, closure requirements and post closure care, recordkeeping, notification, and internet posting requirements. In addition to other requirements, the rule requires existing unlined CCR surface impoundment that is contaminating groundwater to stop receiving CCR and either retrofit or close, except in limited circumstances. The rule also requires the closure of certain landfills and CCR impoundments. The first of these reports was posted to PacifiCorp's CCR compliance data and information websites in March 2018. Based on the results in those reports, additional action was required under the rule. At the time the rule was published in April 2015, PacifiCorp operated 18 surface impoundments and seven landfills that contained CCR. Before the effective date in October 2015, nine surface impoundments and three landfills were either closed or repurposed to no longer receive CCR and hence are not subject to the final rule.

On June 14, 2016, the United States Court of Appeals for the D.C. Circuit ordered the vacatur of the "early closure" provisions in the 2015 CCR rule which would have allowed inactive CCR surface impoundment units that had closed by a certain date to forgo groundwater monitoring or other requirements. In response to this decision, EPA published a direct final rule on August 5, 2016, to extend for certain inactive CCR surface impoundments the compliance deadlines established by the regulations for the disposal of CCR under RCRA.

On July 30, 2018, in response to further legal challenge, EPA finalized a rule to establish alternative performance standards for owners and operators of CCR units located in states that have approved permit programs or are otherwise subject to oversight through a permit program administered by EPA. The rule also revised groundwater protection standards for certain constituents. In addition to adopting alternative performance standards and revising groundwater performance standards for certain constituents, EPA extended the deadline by which facilities must

cease the placement of waste in CCR units closing for cause in certain instances. The first phase of the CCR rule amendments was made effective in August 2018 (the "Phase 1, Part 1 rule").

Following the March 2019 submittal of competing motions from environmental groups, EPA finalized its Holistic Approach to Closure: Part A rule ("Part A rule") on August 28, 2020. The rule reclassified compacted-soil lined surface impoundments from "lined" to "unlined," established a deadline of April 11, 2021, by which unlined surface impoundments that failed aquifer location restriction must initiate closure. In addition, the rule revised the alternative closure provisions to grant facilities additional time to develop alternative capacity to manage both CCR and/or non-CCR wastewater streams before they must stop receiving waste and initiate closure of their surface impoundments. Finally, the rule revised certain requirements related to the annual groundwater monitoring and corrective action report and the requirements for publicly accessible CCR internet sites. A provision in Part A allows demonstrations to be submitted to EPA allowing for operation of unlined CCR ponds beyond the April 11, 2021, deadline for initiation of closure. PacifiCorp has submitted alternative closure demonstrations for the Naughton South Ash Pond and the Jim Bridger flue gas desulfurization (FGD) Pond 2. On October 12, 2023, Jim Bridger FGD Pond 2 ceased receiving waste and the newly constructed FGD Pond 3 was placed into service. EPA was notified on October 12, 2023, of PacifiCorp's withdrawal of its pending Part A alternative storage capacity demonstration request.

On November 12, 2020, EPA published the final Holistic Approach to Closure: Part B rule ("Part B rule"). The Part B rule finalizes a two-step process that allows facilities to request approval to continue operating an existing unlined CCR surface impoundment with an alternate liner system. The other provisions that were contained in the Part B proposal, including (1) options to use CCR during closure of a CCR unit, (2) an additional closure-by-removal option and (3) new requirements for annual closure progress reports, were not finalized with the Part B rule. EPA proposed these options as part of a subsequent proposal on March 3, 2020. On February 20, 2020, EPA published a proposed rule to establish a federal CCR permit program in accordance with the requirements of the Water Infrastructure Improvements for the Nation (WIIN) Act. Until the proposals are finalized and fully litigated, PacifiCorp cannot determine whether additional action may be required.

Separately, on August 15, 2017, EPA published a request for comment on its proposed permitting guidance which describes EPA’s interpretation of the WIIN Act provisions and how EPA will review states' CCR permit programs The state of Utah adopted the federal final rule in September 2016 and issued the final permit for Huntington Power Plant CCR Landfill on March 21, 2023, and for Hunter Power Plant CCR Landfill on May 15, 2024. It is anticipated that Utah will submit an application to EPA for approval, but the timing of the submission remains uncertain. EPA rejected Wyoming’s application due to concerns about the state’s ability to meet federal standards for the safe management of coal ash.

On May 8, 2024, EPA finalized the legacy surface impoundments rule to (1) extend federal CCR regulatory requirements to CCR surface impoundments and landfills that closed prior to the effective date of the 2015 CCR rule, inactive CCR landfills, and other areas where CCR is managed directly on the land (CCR management units or CCRMUs) and (2) allow for alternative closure provisions that allow a facility to complete the closure by removal in two stages. The final rule, which became effective on November 8, 2024, includes exemptions and establishes new categories

where regulation is deferred for applicable units, including CCRMU containing less than 1,000 tons of CCR, CCRMU located beneath critical infrastructure or large buildings or structures vital to the continuation of current site activities, and CCRMU that were closed prior to the effective date of the new rule. Affected facilities must conduct a facility evaluation and report to determine the presence of CCRMUs and/or legacy surface impoundments. The first phase of such a report is due February 2026. Because the facility evaluation and report requirement will determine the magnitude of compliance obligations, PacifiCorp cannot assess the full impacts of the rule at this time.

On August 5, 2024, Utah, Wyoming and other Republican-led states filed a petition for review in the D.C. Circuit on EPA's May 2024 legacy rule, arguing that EPA acted arbitrarily and beyond its authority when enacting the new rule. On February 3, 2025, these same petitioners as well as power companies, utilities and trade groups filed their opening brief in a consolidated case contesting the rule in the D.C. Circuit.

Water Quality Standards

Cooling Water Intake Structures

The federal Water Pollution Control Act (Clean Water Act) establishes the framework for maintaining and improving water quality in the United States through a program that regulates, among other things, discharges to, and withdrawals from, waterways. The Clean Water Act requires that cooling water intake structures reflect the "best technology available for minimizing adverse environmental impact." In August 2014, EPA published a final rule, effective October 2014, under section 316(b) of the Clean Water Act to regulate cooling water intakes at existing facilities. The final rule establishes requirements that apply to existing power generating facilities that withdraw more than two million gallons per day, based on total design intake capacity, of water from Waters of the United States (WOTUS) and use at least 25 percent of the withdrawn water exclusively for cooling purposes. The rule includes standards to address impingement (i.e., when fish and other aquatic organisms are trapped against screens when water is drawn into a facility's cooling system) mortality standards and entrainment (i.e., when organisms are drawn into the facility). The standards will be set on a case-by-case basis to be determined through site-specific studies and will be incorporated into each facility's discharge permit. PacifiCorp's Dave Johnston generating facility withdraws more than two million gallons per day of water from WOTUS for once-through cooling applications. Jim Bridger, Naughton, Gadsby, Hunter, and Huntington generating facilities currently use closed-cycle cooling towers and withdraw more than two million, but less than 125 million, gallons of water per day.

Rule-required permit application requirements (PARs) have been submitted to the appropriate permitting authorities for the Jim Bridger, Naughton, Gadsby, Hunter and Huntington plants. As the five facilities utilize closed-cycle recirculating cooling water systems (cooling towers) exclusively for equipment cooling, it is expected that state agencies will require no further action from PacifiCorp to comply with the rule-required standards. Because Dave Johnston utilizes once-through cooling with withdrawal rates greater than 125 million gallons per day, the facility has been required to conduct more rigorous PARs.

Effluent Limit Guidelines

In November 2015, EPA published final effluent limitation guidelines and standards (ELG) for the steam electric power generating sector which, among other things, regulate the discharge of bottom

ash transport water, fly ash transport water, combustion residual leachate and non-chemical metal cleaning wastes. These guidelines, which had not been revised since 1982, were revised in response to the EPA's concerns that the addition of controls for air emissions has changed the effluent discharged from coal- and natural gas-fueled generating facilities. Under the originally promulgated guidelines, permitting authorities were required to include the new limits in each impacted facility's National Pollutant Discharge Elimination System (NPDES) permit upon renewal with the new limits to be met as soon as possible, beginning November 1, 2018, and fully implemented by December 31, 2023.

On April 5, 2017, a request for reconsideration and administrative stay of the guidelines was filed with EPA. EPA granted the request for reconsideration and extended certain compliance dates for FGD wastewater and bottom ash transport water limits until November 1, 2020. On November 22, 2019, EPA proposed updates to the 2015 rule, specifically addressing FGD wastewater and bottom ash transport water. Those proposals were formalized in rule when the EPA administrator signed the Reconsideration Rule, and it was published in the Federal Register on October 13, 2020. The rule eases selenium limits on FGD wastewater, eases the zero-discharge requirements on bottom ash transport water associated with blowdown of ash handling systems, allows a two-year time extension to meet FGD wastewater requirements and includes additional subcategories to both wastewater categories.

On May 9, 2024, EPA finalized the Supplemental ELG and Standards for the Steam Electric Generating Point Source Category (2024 ELG Rule), which includes a new subcategory for EGUs permanently ceasing coal combustion by 2034. The 2024 ELG Rule also imposes a zero liquid discharge requirement at coal-based generating units for bottom ash transport water, flue gas desulfurization wastewater, and coal combustion residual leachate. The rule also eliminates 2020 ELG Rule's less stringent BAT requirements for two subcategories: high-flow facilities and low-utilization electric generating units (LUEGUs), except to the extent they apply to one new permanent cessation of coal combustion subcategory. The rule maintains, however, the 2020 ELG Rule subcategory for EGUs permanently ceasing the combustion of coal by 2028 and oil-fired and small (50 megawatts (MW) or less) EGUs established in the 2015 rule. The rule finalizes additional reporting and recordkeeping requirements and zero-discharge limitations applicable after EGUs cease coal combustion, as well as procedural requirements for affected facilities to demonstrate permanent cessation of coal combustion or that permanent retirement will occur.

Most of the issues raised by the 2024 ELG Rule are already being addressed at PacifiCorp facilities through compliance with the CCR rule and will not impose significant additional requirements on the facilities. In October 2021, the Dave Johnston plant submitted a notice of planned participation in subcategorization for units ceasing coal combustion by December 31, 2028. Participation in the subcategory allows continued management of bottom ash transport water using impoundments and discharge of the waste stream. The plant requested that the option to transfer to the installation and operation of a bottom ash recycle system be included in the new NPDES permit.

Renewable Generation Regulatory Framework

Regulatory and permitting requirements for renewable energy projects are addressed at federal, state, and local levels. All wind projects in the United States must comply with federal regulations for wildlife impacts, aviation safety, clean water, communication systems, and Department of Defense impacts. Eagle Incidental Take Permits (EITPs), including associated surveys,

monitoring, and compensatory mitigation, are necessary for wind projects that may result in take of bald or golden eagles. State and county regulations often address localized topics such as road and traffic concerns, community economic impacts, viewshed requirements, sage-grouse stipulations, wind turbine location guidelines, and land use and zoning restrictions. Solar projects must comply with federal and state regulations that restrict disturbance of certain flora and fauna and are subject to local planning and zoning regulations for land use. Storm water pollution prevention plans for renewable projects are usually required on a state level to control sediment runoff during construction and all renewable projects must comply with the Clean Water Act rules which are controlled at the federal level. Renewable energy projects located on federally managed lands or that receive federal funding are subject to National Environmental Policy Act (NEPA) review, which may include cultural and biological resource surveys, assessment of potential impacts, public comment periods, and avoidance/minimization/mitigation efforts. Power lines associated with renewable energy projects, including collector lines at the project site and grid-connecting transmission lines, may also be subject to environmental regulations, review, stipulations, or permits.

The wind projects (TB Flats, Ekola Flats, and Cedar Springs) constructed as part of PacifiCorp's Energy Vision 2020 initiative, for example, were required to obtain permits from the State of Wyoming's Industrial Siting Division, which required extensive studies of the conditions of the site, coordination with state agencies in the development process, and forecast of impacts from the project. Renewable energy projects in the State of Wyoming that meet the Industrial Siting Division's size or capital thresholds must obtain approval before they can begin construction. Most wind project developers coordinate with federal and/or state authorities to evaluate and mitigate potential impacts to birds or other wildlife species, particularly eagles, migratory birds, and bats, during the wind turbine siting process to minimize wildlife impacts and potential operational risks. Greater sage-grouse are currently managed by the states, and renewable energy projects and associated transmission lines require state agency review; stipulations or mitigation requirements vary by state and project impacts. Because the generation capabilities of renewable energy projects are site specific and can vary greatly between different sites, understanding the specific permit requirements for each site is critical to developing a successful project.

State Policy Update

California

Under the authority of the Global Warming Solutions Act, the California Air Resources Board (CARB) adopted a greenhouse gas cap-and-trade program in October 2011, with an effective date of January 1, 2012; compliance obligations were imposed on regulated entities beginning in 2013. PacifiCorp is required to sell, through the auction process, its directly allocated allowances and purchase the required allowances necessary to meet its compliance obligations.

In May 2014, CARB approved the first update to the Assembly Bill (AB) 32 Climate Change scoping plan, which defined California's climate change priorities for the next five years and set the groundwork for post-2020 climate goals. In April 2015, Governor Brown issued an executive order to establish a mid-term reduction target for California of 40 percent below 1990 levels by 2030. CARB has subsequently been directed to update the AB 32 scoping plan to reflect the new interim 2030 target and previously established 2050 target. CARB's 2022 Scoping Plan was

adopted laying out a path to achieve targets for carbon neutrality and reduce anthropogenic greenhouse gas emissions by 85 percent below 1990 levels no later than 2045, as directed by Assembly Bill 1279, passed in 2022.

CARB adopted the Advanced Clean Cars II Rule in August of 2022. The rulemaking establishes that by 2035 all new passenger cars, trucks and SUVs sold in California will be zero emissions. The Advanced Clean Cars II regulations take the state's already growing zero-emission vehicle market and robust motor vehicle emission control rules and augments them to meet more aggressive tailpipe emissions standards and ramp up to 100% zero-emission vehicles.

In 2002, California established a RPS requiring investor-owned utilities to increase procurement from eligible renewable energy resources. California's RPS requirements have been accelerated and expanded several times since its inception. In September 2018, Governor Brown signed into law Senate Bill (SB) 100, which requires utilities to procure 60 percent of their electricity from renewables by 2030 and enabled all the state's agencies to work toward a longer-term planning target for 100 percent of California's electricity to come from renewable and zero-carbon resources by December 31, 2045. The California Energy Commission, California Public Utilities Commission, and California Air Resources Board have not introduced rules on if and how electric utilities will demonstrate compliance with SB 100. Interim targets for the carbon-free target were subsequently adopted by SB 1020 in 2022.

Idaho

In 2007, Idaho released its State Energy Plan, focusing on developing of a broad range of power generation options, improving energy efficiency, diversifying the state's energy portfolio, and reducing dependency on fossil fuels. The plan outlined strategies for energy conservation, the development of renewable energy sources, and improvements to transmission infrastructure within the state, aiming to balance growth with environmental stewardship and promote both economic development and sustainable energy practices.

In 2012, Idaho updated its 2007 plan to address new energy challenges and opportunities, emphasizing five core objectives: 1) a secure and stable energy system for Idaho's citizens and businesses, 2) maintaining Idaho's low-cost energy supply, 3) protecting public health and conserving natural resources, 4) promoting economic growth, job creation, and rural economic development, and 5) ensuring Idaho's energy policy can adapt to changing circumstances.

In October of 2020, Governor Brad Little issued Executive Order 2020-17, continuing the role of the Office of Energy and Mineral Resources (OEMR) as the central coordinator for Idaho's energy policy. The OEMR manages energy production, conservation, and policy alignment, ensuring the state's energy resources remain stable and cost-effective.

Oregon

In 2007, the Oregon Legislature passed House Bill (HB) 3543 – Global Warming Actions, which establishes greenhouse gas reduction goals for the state that: (1) end the growth of Oregon greenhouse gas emissions by 2010; (2) reduce greenhouse gas levels to ten percent below 1990 levels by 2020; and (3) reduce greenhouse gas levels to at least 75 percent below 1990 levels by 2050. In 2009, the legislature passed SB 101, which requires the Public Utility Commission of

Oregon (OPUC) to submit a report to the legislature before November 1 of each even-numbered year regarding the estimated rate impacts for Oregon's regulated electric and natural gas companies of meeting the greenhouse gas reduction goals of ten percent below 1990 levels by 2020 and 15 percent below 2005 levels by 2020. The OPUC submitted its most recent report November 1, 2014.

In 2007, Oregon enacted Senate Bill (SB) 838 establishing an RPS requirement in Oregon. Under SB 838, utilities are required to deliver 25 percent of their electricity from renewable resources by 2025. On March 8, 2016, Governor Kate Brown signed SB 1547-B, the Clean Electricity and Coal Transition Plan, into law. SB 1547-B extends and expands the Oregon RPS requirement to 50 percent of electricity from renewable resources by 2040 and requires that coal-fueled resources are eliminated from Oregon's allocation of electricity by January 1, 2030. The increase in the RPS requirements under SB 1547-B is staged as follows: 27 percent for 2025-2029, 35 percent for 2030-2034, 45 percent for 2035-2039, and 50 percent for 2040 and every subsequent year thereafter. The bill changes the renewable energy certificate (REC) life to five years, while allowing RECs generated from the effective date of the bill passage until the end of 2022 from new long-term renewable projects to have unlimited life. The bill also includes provisions to create a community solar program in Oregon and encourage greater reliance on electricity for transportation.

On March 10, 2020, Oregon Governor Kate Brown issued Executive Order 20-04 (EO 20-04), which directs state agencies to take actions to reduce and regulate greenhouse gas emissions.

EO 20-04 establishes emissions reduction goals for Oregon and directs certain state agencies to take specific actions to reduce emissions and mitigate the impacts of climate change. EO 20-04 also provides overarching direction to state agencies to exercise their statutory authority to help achieve Oregon's climate goals.

In 2021, Oregon passed House Bill 2021, which directs utilities to reduce emissions levels below 2010-2012 baseline levels by 80% by 2030, 90% by 2035, and 100% by 2040. HB 2021 also expanded the capacity standard for Small Scale Renewables from 8% to 10%. PacifiCorp filed its first Clean Energy Plan (CEP) on May 31, 2023, which included possible pathways towards compliance with HB 2021 emissions reduction goals, inclusive of the Small-Scale Renewable (SSR) targets and with emphasis on community-based actions. As also directed by HB 2021, PacifiCorp convened a Community Benefits and Impacts Advisory Group in the fall of 2022. An Oregon Tribal Nations Clean Energy-specific engagement series was started in March of 2023 after six months of direct outreach. The engagement series was formatted by informed feedback from outreach to Oregon Tribal Nations members with whom PacifiCorp had an existing relationship, and through new Tribal Nations relationship building.

In December 2022, Oregon Department of Environmental Quality adopted the Advanced Clean Cars II Rulemaking on Low and Zero Emission Vehicles which requires 100% of new light-duty vehicles (LDVs) be zero-emission vehicles (ZEVs) or PHEVs by 2035, ramping up from an initial requirement that 35% of new LDVs be ZEVs in 2026 this follows the CARB rulemaking. In Jan of 2022, HB 2165 passed requiring that all electricity companies (with ≥25,000 retail customers) recover the cost of prudent infrastructure investments in transportation electrification. Furthermore, in November 2021, Oregon adopted California's emission standards for HMDV via

the Advanced Clean Truck Rules 2021, paving the way for Oregon to adopt a target of 100% of new MHDV sales being ZEVs by 2050.

Washington

In November 2006, Washington voters approved Initiative 937 (I-937), the Washington Energy Independence Act, which imposes targets for energy conservation and the use of eligible renewable resources on electric utilities. Under I-937, utilities must supply 15 percent of their energy from renewable resources by 2020 and every year thereafter. Utilities must also set and meet energy conservation targets starting in 2010.

In 2008, the Washington Legislature approved the Climate Change Framework E2SHB 2815, which establishes the following state greenhouse gas emissions reduction limits: (1) reduce emissions to 1990 levels by 2020; (2) reduce emissions to 25 percent below 1990 levels by 2035; and (3) by 2050, reduce emissions to 50 percent below 1990 levels or 70 percent below Washington's forecasted emissions in 2050.

In 2019, the Washington Legislature passed the Clean Energy Transformation Act (CETA) which requires utilities to eliminate coal-fired resources from Washington rates by December 31, 2025, be carbon neutral by January 1, 2030, and establishes a target of 100 percent of its retail electricity sales be supplied from renewable and non-emitting resources by 2045. PacifiCorp submitted its inaugural Clean Energy Implementation Plan (CEIP) on December 30, 2023, establishing a trajectory towards CETA compliance both for the current CEIP period, 2022 – 2025, and across the next two decades.

In 2021, Washington Legislature passed the Climate Commitment Act, which establishes a cap-and-invest program that came into effect January 1, 2023. The Climate Commitment Act does not modify any of PacifiCorp's obligations under CETA, and utilities that are subject to CETA are allocated allowances within the cap-and-trade program at no cost, for emissions associated with serving Washington retail load. The legislation allows – but does not require – linkage with cap-and-trade programs in jurisdictions outside of Washington State.

In December 2022, Department of Ecology adopted the Advanced Clean Cars II Rulemaking on Low and Zero Emission Vehicles which requires 100% of new light-duty vehicles (LDVs) be zero-emission vehicles (ZEVs) or PHEVs by 2035, ramping up from an initial requirement that 35% of new LDVs be ZEVs in 2026 this follows the CARB rulemaking. Furthermore, in December 2021, Washington adopted California's emission standards for HMDV via the Advanced Clean Truck Rules 2021. In 2022, Department of Ecology passed the Clean Fuel Standard law requires fuel suppliers to gradually reduce the carbon intensity of transportation fuels to 20% below 2017 levels by 2034. There are several ways for fuel suppliers to achieve these reductions, including:

- Improving the efficiency of their fuel production processes
- Producing and/or blending low-carbon biofuels into the fuel they sell
- Purchasing credits generated by low-carbon fuel providers, including electric vehicle charging providers

Utah[9]

In March 2008, Utah enacted the Energy Resource and Carbon Emission Reduction Initiative, which includes provisions to require utilities to pursue renewable energy to the extent that it is cost effective. It sets out a goal for utilities to use eligible renewable resources to account for 20 percent of their 2025 adjusted retail electric sales.

In April 2019, the Utah Legislature passed HB 411, Community Renewable Program, which allowed cities and municipalities in Utah to elect to participate on behalf of their residents. The Community Renewable Program is an opt-out program with the goal of being 100% net renewable by 2030. Customers within a participating community may opt out of the program and maintain existing rates. The legislation prohibits cost shifting to non-participating customers. By the end of 2019, 23 Utah communities passed a resolution as required by the legislation to participate in the program. Program design efforts are underway and ongoing.

On March 11, 2020, the Utah Legislature passed HB 396, Electric Vehicle Charging Infrastructure Amendments, which enables PacifiCorp to create an Electrical Vehicle Infrastructure Program, with a maximum funding from customers of $50 million for all costs and expenses. The legislation allows PacifiCorp to own and operate electric vehicle charging stations and to provide investments in make-ready infrastructure to interested customers. The Public Service Commission of Utah approved the Electric Vehicle Infrastructure Program on December 20, 2021, for implementation on January 1, 2022. The program construct will undergo regulatory review every three years through 2032.

In March 2024, the Utah Legislature passed SB 224, Energy Independence Amendments, that modifies the factors the Public Service Commission must consider when evaluating certain proposed energy resource decisions, establishes parameters for an affected electrical utility's recovery of costs associated with proven dispatchable generation resources located within the state, and encourages the commission to evaluate the purchase of excess proven dispatchable generation capacity.

In March 2024, the Utah Legislature passed HB 191, Electrical Energy Amendments, which requires the Public Service Commission to act in accordance with the state energy policy and make certain determinations before authorizing the early retirement of an electrical generation facility.

Wyoming

On March 8, 2019, Wyoming Senate File 0159 (SF 159) was passed into law. SF 159 limits the recovery costs for the retirement of coal fired electric generation facilities, provides a process for the sale of an otherwise retiring coal fired electric generation facility, exempts a person purchasing an otherwise retiring coal fired electric generation facility from regulation as a public utility;

[9] Significant Utah legislative activity gathered interest in the 2025 IRP public input meeting series and stakeholder feedback. Regarding Utah SB-224, see Appendix M, stakeholder feedback form #13 (Emma Verhamme). Portfolio planning is currently not directly impacted by Utah SB-224, however variant and sensitivity studies may reflect this potential, such as the Low-Cost Renewables case and the No Coal 2032 case. Additional discussion of Utah activity is addressed in Appendix M, stakeholder feedback form #37 (Utah Citizens Advocating Renewable Energy).

requires purchase of electricity generated from purchased retiring coal fired electric generation facility (as specified in final bill); and provides an effective date.

Cost recovery associated with electric generation built to replace a retiring coal fired generation facility shall not be allowed by the Wyoming Public Service Commission unless the Commission has determined that the public utility made a good faith effort to sell the facility to another person prior to its retirement and that the public utility did not refuse a reasonable offer to purchase the facility or the Commission determines that, if a reasonable offer was received, the sale was not completed for a reason beyond the reasonable control of the public utility.

Under SF 159 electric public utilities, other than cooperative electric utilities, shall be obligated to purchase electricity generated from a coal fired electric generation facility purchased under agreement approved by the Commission, provided the otherwise retiring coal fired electric generation facility offers to sell some or all of the electricity from the facility to an electric public utility, the electricity is sold at a price that is no greater than the purchasing electric utility's avoided cost, the electricity is sold under a power purchase agreement, and the Commission approves a 100 percent cost recovery in rates for the cost of the power purchase agreement and the agreement is 100 percent allocated to the public utility's Wyoming customers unless otherwise agreed to by the public utility.

In March 2020, the Wyoming legislature passed House Bill 200 (HB 200), Reliable and Dispatchable Low-Carbon Energy Standards. HB 200 required the Wyoming Public Service Commission to put in place a standard for each public utility specifying a percentage of electricity to be generated from coal-fired generation utilizing carbon capture technology by 2030. The requirement applies to generation allocated to Wyoming customers. HB 200 requires each public utility to demonstrate in its IRP the steps taken to achieve the electricity generation standard established by the Commission and will allow rate recovery of costs incurred by a public utility that utilizes coal-fired generation with carbon capture technology installed. The Wyoming Public Service Commission implemented new administrative rules Low-Carbon Energy Portfolio Standards that went into effect in January 2022 requiring public utilities to file an initial plan to establish intermediate standards and requirements no later than March 31, 2022. A final plan must be filed by March 31, 2023, and include a low-carbon energy portfolio standard of no less than 20 percent unless it is not economically or technically feasible. During the 2024 legislative session the Reliable and Dispatchable Low-Carbon Energy Standard statute was amended through SF 42, which extended the deadline for compliance with the Low-Carbon Energy Standards from July 1, 2030, to July 1, 2033.

In 2024, the Wyoming legislature passed SF 0023 Public Utilities-Energy Resource Procurement (SF 23) and SF 0024 Public Service Commission-Integrated Resource Plans (SF 24). SF 23 requires public utilities to conduct a solicitation process that is approved by the Wyoming Public Service Commission to acquire or construct a significant energy resource after July 1, 2024. A significant energy resource consists of 100 megawatts or more of new utility-owned generating capacity or utility-contracted generating capacity that has a dependable life or contract term of 10 or more years. SF 24 requires the Wyoming Public Service Commission to engage in long-range planning regarding public utility regulatory policy to facilitate the well-planned development and conservation of utility resources and requires the Commission to adopt rules providing a process for the review and acknowledgement of an action plan within an IRP.

Greenhouse Gas Emission Performance Standards

California, Oregon and Washington have greenhouse gas emission performance standards applicable to all electricity generated in the state or delivered from outside the state that is no higher than the greenhouse gas emission levels of a state-of-the-art combined cycle natural gas generation facility. The standards for Oregon and California are currently set at 1,100 lb CO_2/MWh, which is defined as a metric measure used to compare the emissions from various greenhouse gases based on their global warming potential. Effective February 2025, the Washington Department of Commerce issued a new rule lowering the emissions performance standard to 876 lb GHG/MWh.

PacifiCorp purchased Chehalis in 2008 and this change in ownership is the act that triggered the applicability of the standard. Because the EPS was 1,100 lb GHG/MWh during the time of triggered applicability, that is the standard that Chehalis complies with. It isn't until Chehalis undergoes a change in ownership, upgrade, or new or renewed long-term financial commitment with anyone other than Bonneville Power Administration that applicability to the lowered standard would be triggered.

Renewable Portfolio Standards

An RPS requires a retail seller of electricity to include in its resource portfolio a certain amount of electricity from renewable energy resources, such as wind, geothermal and solar energy. The retailer can satisfy this obligation by using renewable energy from its own facilities, purchasing renewable energy from another supplier's facilities, using Renewable Energy Credits (RECs) that certify renewable energy has been generated, or a combination of all of these.

RPS policies are currently implemented at the state level and vary considerably in their renewable targets (percentages), target dates, resource/technology eligibility, applicability of existing plants and contracts, arrangements for enforcement and penalties, and use of RECs.

In PacifiCorp's service territory, California, Oregon, and Washington have each adopted a mandatory RPS, and Utah has adopted a RPS goal. Each of these states' legislation and requirements are summarized in Table 3.3, with additional discussion below.

Table 3.3 – State RPS Requirements

	California	Oregon	Washington	Utah
Legislation	• Senate Bill 1078 (2002) • Assembly Bill 200 (2005) • Senate Bill 107 (2006) • Senate Bill 2 First Extraordinary Session (2011) • Senate Bill 350 (2015) • Senate Bill 100 (2018)	• Senate Bill 838 Oregon Renewable Energy Act (2007) • House Bill 3039 (2009) • House Bill 1547-B (2016)	• Initiative Measure No. 937 (2006) • SB 5400 (2013)	• Senate Bill 202 (2008)
Requirement or Goal	• 20% by December 31, 2013 • 25% by December 31, 2016 • 33% by December 31, 2020 • 44% by December 31, 2024 • 52% by December 31, 2027 • 60% by December 31, 2030 and beyond • Planning target of 100% renewable and zero-carbon by 2045 * Based on the retail load for a three-year compliance period	• 5% by December 31, 2011 • 15% by December 31, 2015 • 20% by December 31, 2020 • 27% by December 31, 2025 • 35% by December 31, 2030 • 45% by December 31, 2035 • 50% by December 31, 2040 * Based on the retail load for that year	• 3% by January 1, 2012 • 9% by January 1, 2016 • 15% by January 1, 2020 and beyond * Annual targets are based on the average of the utility's load for the previous two years	• Goal of 20% by 2025 (must be cost effective) • Annual targets are based on the adjusted[10] retail sales for the calendar year 36 months before the target year

California

California originally established its RPS program with passage of SB 1078 in 2002. Several bills have since been passed into law to amend the program. In the 2011 First Extraordinary Special Session, the California Legislature passed SB 2 (1X) to increase California's RPS to 33 percent by 2020.[11] SB 2 (1X) also expanded the RPS requirements to all retail sellers of electricity and publicly owned utilities. In October 2015, SB 350, the Clean Energy and Pollution Reduction Act, was signed into law.[12] SB 350 established a greenhouse gas reduction target of 40 percent below 1990 levels by 2030 and 80 percent below 1990 levels by 2050 and expanded the state's renewables portfolio standard to 50 percent by 2030. In September 2018, the signing of SB 100, the Clean Energy Act of 2018, further expanded and accelerated the California RPS to 60 percent by 2030 and directed the state's agencies to plan for a longer-term goal of 100 percent of total retail sales of electricity in California to come from eligible renewable and zero-carbon resources by December 31, 2045.

SB 2 (1X) created multi-year RPS compliance periods, which were expanded by SB 100. The California Public Utilities Commission approved compliance periods and corresponding RPS procurement requirements, which are shown in Table 3.4 below.

[10] Adjustments for generated or purchased from qualifying zero carbon emissions and carbon capture storage and DSM.
[11] www.leginfo.ca.gov/pub/11-12/bill/sen/sb_0001-0050/sbx1_2_bill_20110412_chaptered.pdf
[12] leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350

Table 3.4 – California Compliance Period Requirements

Compliance Period	Procurement Quantity Requirement Calculation
Compliance Period 1 (2011-2013)	(20% * 2011 Retail Sales) + (20% * 2012 Retail Sales) + (20% * 2013 Retail Sales)
Compliance Period 2 (2014-2016)	(21.7% * 2014 Retail Sales) + (23.3% * 2015 Retail Sales) + (25% * 2016 Retail Sales)
Compliance Period 3 (2017-2020)	(27% * 2017 Retail Sales) + (29% * 2018 Retail Sales) + (31% * 2019 Retail Sales) + (33% * 2020 Retail Sales)
Compliance Period 4 (2021-2024)	(35.75% * 2021 Retail Sales) + (38.5% * 2022 Retail Sales) + (41.25% * 2023 Retail Sales) + (44% * 2024 Retail Sales)
Compliance Period 5 (2025-2027)	(46.67% * 2025 Retail Sales) + (49.33% * 2026 Retail Sales) + (52% * 2027 Retail Sales)
Compliance Period 6 (2028-2030)	(54.67% * 2028 Retail Sales) + (57.33% * 2029 Retail Sales) + (60% * 2030 Retail Sales)

SB 2 (1X) established new "portfolio content categories" for RPS procurement, which delineated the type of renewable product that may be used for compliance and set minimum and maximum limits on certain procurement content categories that can be used for compliance.

Portfolio Content Category 1 includes eligible renewable energy and RECs that meet either of the following criteria:

> Have a first point of interconnection with a California balancing authority, have a first point of interconnection with distribution facilities used to serve end users within a California balancing authority area, or are scheduled from the eligible renewable energy resource into a California balancing authority without substituting electricity from another source; or
>
> Have an agreement to dynamically transfer electricity to a California balancing authority.

Portfolio Content Category 2 includes firmed and shaped eligible renewable energy resource electricity products providing incremental electricity and scheduled into a California balancing authority.

Portfolio Content Category 3 includes eligible renewable energy resource electricity products, or any fraction of the electricity, including unbundled renewable energy credits that do not qualify under the criteria of Portfolio Content Category 1 or Portfolio Content Category 2.[13]

Additionally, the CPUC established the balanced portfolio requirements for contracts executed after June 1, 2010. The balanced portfolio requirements set minimum and maximum levels for the Procurement Content Category products that may be used in each compliance period as shown in Table 3.5.

[13] A REC can be sold either "bundled" with the underlying energy or "unbundled" as a separate commodity from the energy itself into a separate REC trading market.

Table 3.5 – California Balanced Portfolio Requirements

California RPS Compliance Period	Balanced Portfolio Requirement
Compliance Period 1 (2011-2013)	Category 1 – Minimum of 50% of Requirement Category 3 – Maximum of 25% of Requirement
Compliance Period 2 (2014-2016)	Category 1 – Minimum of 65% of Requirement Category 3 – Maximum of 15% of Requirement
Compliance Period 3 (2017-2020) Compliance Period 4 (2021-2024) Compliance Period 5 (2025-2027) Compliance Period 6 (2028-2030)	Category 1 – Minimum of 75% of Requirement Category 3 – Maximum of 10% of Requirement

In December 2011, the CPUC confirmed that multi-jurisdictional utilities, such as PacifiCorp, are not subject to the percentage limits in the three portfolio content categories. PacifiCorp is required to file annual compliance reports with the CPUC, and annual procurement reports with the California Energy Commission (CEC). Neither SB 350 nor SB 100 changed the portfolio content categories for eligible renewable energy resources, or the portfolio balancing requirements exemption provided to PacifiCorp. For utilities subject to the portfolio balancing requirements, the CPUC extended the compliance period 3 requirements through 2030.

The full California RPS statute is listed under Public Utilities Code Section 399.11-399.32. Additional information on the California RPS can be found on the CPUC and CEC websites. Qualifying renewable resources include solar thermal electric, photovoltaic, landfill gas, wind, biomass, geothermal, municipal solid waste, energy storage, anaerobic digestion, small hydroelectric, tidal energy, wave energy, ocean thermal, biodiesel, and fuel cells using renewable fuels. Renewable resources must be certified as eligible for the California RPS by the CEC and tracked in the Western Renewable Energy Generation Information System (WREGIS).

Oregon

In June of 2007, Oregon established a comprehensive renewable energy policy, including RPS, with the passage of SB 838, the Oregon Renewable Energy Act. [14] Subject to certain exemptions and cost limitations established in the Oregon Renewable Energy Act, PacifiCorp and other qualifying electric utilities must meet a target of at least 25 percent renewable energy by 2025. In March 2016, the Legislature passed SB 1547,[15] also referred to as Oregon's Clean Electricity and Coal Transition Act. In addition to requiring Oregon to transition off coal by 2030, the new law doubled Oregon's RPS requirements, which are set at 27 percent by 2025, 35 percent by 2030, 45 percent by 2035, and 50 percent by 2040 and beyond. Other components of SB 1547 include:

- Development of a community solar program with at least 10 percent of the program capacity reserved for low-income customers.
- A requirement that by 2025, at least eight percent of the aggregate electric capacity of the state's investor-owned utilities must come from small-scale renewable projects under 20 megawatts.

[14] www.leg.state.or.us/07reg/measpdf/sb0800.dir/sb0838.en.pdf
[15] olis.leg.state.or.us/liz/2016R1/Downloads/MeasureDocument/SB1547/Enrolled

- Creates new eligibility for pre-1995 biomass plants and associated thermal co-generation. Under the previous law, pre-1995 biomass was not eligible until 2026.
- Direction to the state's investor-owned utilities to propose plans encouraging greater reliance on electricity in all modes of transportation, to reduce carbon emissions.
- Removal of the Oregon Solar Initiative mandate.[16]

SB 1547 also modified the Oregon REC banking rules as follows:

- RECs generated before March 8, 2016, have an unlimited life.
- RECs generated during the first five years for long-term projects coming online between March 8, 2016, and December 31, 2022, have an unlimited life.
- RECs generated on or after March 8, 2016, from resources that came online before March 8, 2016, expire five years beyond the year the REC was generated.
- RECs generated beyond the first five years for long-term projects coming online between March 8, 2016, and December 31, 2022, expire five years beyond the year the REC is generated.
- RECs generated from projects coming online after December 31, 2022, expire five years beyond the year the REC is generated.
- Banked RECs can be surrendered in any compliance year regardless of vintage (eliminates the "first-in, first-out" provision under SB 838).

To qualify as eligible, the RECs must be from a resource certified as Oregon RPS eligible by the Oregon Department of Energy and tracked in WREGIS. Qualifying renewable energy sources can be located anywhere in the United States portion of the Western Electricity Coordinating Council geographic area, and a limited amount of unbundled renewable energy credits can be used toward the annual compliance obligation. Eligible renewable resources include electricity generated from wind, solar photovoltaic, solar thermal, wave, tidal, ocean thermal, geothermal, certain types of biomass and biogas, municipal solid waste, and hydrogen power stations using anhydrous ammonia.

Electricity generated by a hydroelectric facility is eligible if the facility is not located in any federally protected areas designated by the Pacific Northwest Electric Power and Conservation Planning Council as of July 23, 1999, or any area protected under the federal Wild and Scenic Rivers Act, P.L. 90-542, or the Oregon Scenic Waterways Act, ORS 390.805 to 390.925; or if the electricity is attributable to efficiency upgrades made to the facility on or after January 1, 1995, and up to 50 average megawatts of electricity per year generated by a certified low-impact hydroelectric facility owned by an electric utility and up to 40 average megawatts of electricity per year generated by certified low-impact hydroelectric facilities not owned by electric utilities.

PacifiCorp files an annual RPS compliance report by June 1 of every year. In addition, after the passage of Oregon House Bill 3161, effective January 1, 2024, ORS 469A.075 now aligns the filing of a renewable plan (formally called the Renewable Portfolio Implementation Plan or RPIP) with the filing of the IRP. Please see Appendix R for detailed information on PacifiCorp's 2025

[16] In 2009, Oregon passed House Bill 3039, also called the Oregon Solar Initiative, requiring that on or before January 1, 2020, the total solar photovoltaic generating nameplate capacity must be at least 20 megawatts from all electric companies in the state. The Public Utility Commission of Oregon determined that PacifiCorp's share of the Oregon Solar Initiative was 8.7 megawatts.

RPS Renewable Plan, including annual targets, list of resources, applicable requirements, and assumptions and methodologies. These RPS compliance reports and plans are available on PacifiCorp's website.[17]

The full Oregon RPS statute is listed in Oregon Revised Statutes (ORS) Chapter 469A and the solar capacity standard is listed in ORS Chapter 757. The Public Utility Commission of Oregon rules are in Oregon Administrative Rules (OAR) Chapter 860 Division 083 for the RPS and OAR Chapter 860 Division 084 for the solar photovoltaic program. The Oregon Department of Energy rules are under OAR Chapter 330 Division 160.

Utah

In March 2008, Utah's governor signed Utah SB 202, the Energy Resource and Carbon Emission Reduction Initiative, later codified in Utah Code Title 54 Chapter 17.[18] This law provides that, beginning in the year 2025, 20 percent of adjusted retail electric sales of all Utah utilities be supplied by renewable energy if it is cost effective. Retail electric sales will be adjusted by deducting the amount of generation from sources that produce zero or reduced carbon emissions and for sales avoided because of energy efficiency and demand side management programs. Qualifying renewable energy sources can be located anywhere in the Western Electricity Coordinating Council areas, and unbundled renewable energy credits can be used for up to 20 percent of the annual qualifying electricity target.

Eligible renewable resources include electricity from a facility or upgrade that becomes operational on or after January 1, 1995, that derives its energy from wind, solar photovoltaic, solar thermal electric, wave, tidal or ocean thermal, certain types of biomass and biomass products, landfill gas or municipal solid waste, geothermal, waste gas and waste heat capture or recovery, and efficiency upgrades to hydroelectric facilities if the upgrade occurred after January 1, 1995. Up to 50 average megawatts from a certified low-impact hydro facility and in-state geothermal and hydro generation without regard to operational online date may also be used toward the target. To assist solar development in Utah, solar facilities located in Utah receive credit for 2.4 kilowatt-hours of qualifying electricity for each kWh of generation.

Under the Carbon Reduction Initiative, PacifiCorp is required to file a progress report by January 1 of each of the years 2010, 2015, 2020 and 2024.

PacifiCorp filed its most recent progress report on December 29, 2023. This report showed that the company is positioned to meet its 20 percent target requirement of approximately 5.0 million megawatt-hours of renewable energy in 2025 from existing company-owned and contracted renewable energy sources.

In 2027, the legislation requires a commission report to the Utah Legislature, which may contain any recommendation for penalties or other action for failure to meet the 2025 target. The legislation requires that any recommendation for a penalty must provide that the penalty funds be used for demand side management programs for the customers of the utility paying the penalty.

[17] www.pacificpower.net/ORrps
[18] le.utah.gov/~2008/bills/sbillenr/sb0202.pdf

Washington

In November 2006, Washington voters approved I-937, a ballot measure establishing the Energy Independence Act, which is an RPS and energy efficiency requirement applied to qualifying electric utilities, including PacifiCorp.[19] The law requires that qualifying utilities procure at least three percent of retail sales from eligible renewable resources or RECs by January 1, 2012 through 2015; nine percent of retail sales by January 1, 2016 through 2019; and 15 percent of retail sales by January 1, 2020, and every year thereafter.

Eligible renewable resources include electricity produced from water, wind, solar energy, geothermal energy, landfill gas, wave, ocean, or tidal power, gas from sewage treatment facilities, biodiesel fuel with limitation, and biomass energy based on organic byproducts of the pulp and wood manufacturing process, animal waste, solid organic fuels from wood, forest, or field residues, or dedicated energy crops. Qualifying renewable energy sources must be located in the Pacific Northwest or delivered into Washington on a real-time basis without shaping, storage, or integration services. The only hydroelectric resource eligible for compliance is electricity associated with efficiency upgrades to hydroelectric facilities. Utilities may use eligible renewable resources, RECs, or a combination of to meet the RPS requirement.

PacifiCorp is required to file an annual RPS compliance report by June 1 of every year with the Washington Utilities and Transportation Commission (WUTC) demonstrating compliance with the Energy Independence Act. PacifiCorp's compliance reports are available on PacifiCorp's website.[20]

The WUTC adopted final rules to implement the initiative; the rules are listed in the Revised Code of Washington (RCW) 19.285 and the Washington Administrative Code (WAC) 480-109.

REC Management Practices

PacifiCorp provides the following summary of REC management practices in compliance with Order 20-186 in Oregon. The company intends to maximize the value of RECs for customers either through retirement for compliance purposes or monetization through sales. As a multi-state utility, PacifiCorp has Renewable Portfolio Standards in Washington, Oregon, and California, and a Renewable Portfolio Goal in 2025 in Utah. PacifiCorp generally retains and retires RECs allocated to Washington, Oregon, and California for compliance purposes, but requests flexibility to manage its RECs based on opportunities it sees in the market, which may include selling RECs at a favorable price and acquiring RECs at a lower price. The company maximizes the sale of RECs allocated to Utah, Idaho, and Wyoming and allocates the revenue from those sales to those states. One exception to REC sales is a special contract for one industrial customer where the customer foregoes REC sales revenue in exchange for a REC retirement to maintain renewable claims for corporate sustainability goals. An expansion of this program is currently under development to be offered under a new tariff in Utah, Idaho and Wyoming.

[19] www.secstate.wa.gov/elections/initiatives/text/I937.pdf
[20] www.pacificpower.net/report

Clean Energy Standards

Washington

In 2019, Governor Jay Inslee signed into law Senate Bill 5116, the Clean Energy Transformation Act (CETA). Under the law, Washington utilities are required to be carbon neutral by January 1, 2030, and institute a planning target of 100 percent clean electricity by 2045. The bill establishes four-year compliance periods beginning January 1, 2030, and requires utilities to use electricity from renewable resources and non-emitting electric generation in an amount equal to 100 percent of the retail electric sales over each compliance period. Through December 31, 2044, an electric utility may satisfy up to 20 percent of its compliance obligation with an alternative compliance option such as the purchase of unbundled RECs.

Oregon

As noted under State Policy Updates, above, in July 2021, Oregon Governor Kate Brown signed into law House Bill 2021, which set emissions reduction targets for utilities and electricity providers. Under the law, retail electricity providers shall reduce greenhouse gas emissions by 80 percent below baseline emissions levels by 2030, by 90 percent below baseline emissions level by 2035, and by 100 percent below baseline emissions levels by 2040.

California

In 2018, California passed Senate Bill 100 – known as the "100 percent Clean Energy Act of 2018," which sets a 2045 goal of powering all retail electricity sold in California with renewable and zero-carbon resources. The law also updates the state's Renewables Portfolio Standard to ensure that by 2030 at least 60 percent of California's electricity is renewable.

In 2022, California passed Senate Bill 1020, the Clean Energy, Jobs, and Affordability Act of 2022. This bill established interim targets to the previously established SB 100. It requires that eligible renewable energy resources and zero-carbon resources supply:

- 90% of all retail sales of electricity to California end-use customers by December 31, 2035
- 95% of all retail sales of electricity to California end-use customers by December 31, 2040
- 100% of all retail sales of electricity to California end-use customers by December 31, 2045
- 100% of electricity procured to serve all state agencies by December 31, 2030

In 2022, California passed Senate Bill 1158. This bill requires the State Energy Resources Conservation and Development Commission to adopt guidelines for the reporting and disclosure of electricity sources by the hour. The bill includes hourly power source reporting as a new set of reporting requirements at the Energy Commission and allows for the commission to modify those requirements for small entities with under 60,000 customers in California, like Pacific Power. In February 2025, the Commission adopted final rules that exempted multijurisdictional electric companies with 60,000 or fewer customers in California from compliance with the hourly reporting requirement.

Wyoming

In July 2020, House Bill 200 (HB 200), Reliable and Dispatchable Low-Carbon Energy Standards went into effect requiring the Wyoming Public Service Commission to put in place a standard for each public utility specifying a percentage of electricity to be generated from coal-fired generation utilizing carbon capture technology by 2030. The Wyoming Public Service Commission implemented rules for Low-Carbon Energy Portfolio Standards that went into effect in January 2022 requiring public utilities to file an initial plan to establish intermediate standards and requirements no later than March 31, 2022. A final plan must be filed by March 31, 2023, and include a final low-carbon energy portfolio standard of no less than 20 percent unless it is not economically or technically feasible. The Company requested an extension and filed the final plan on March 29, 2024 that included a proposal to: conduct additional technical and economic analyses for an Allam Fetvedt Cycle Project at either the Dave Johnston or Wyodak facilities by conducting a pre-FEED study in conjunction with SK and 8 Rivers; conduct additional technical and economic analyses by conducting a front-end engineering and design (FEED) study at the Jim Bridger facility; and no determination of a low-carbon portfolio standard at this time since CCUS continues to be evaluated for its technical and economic feasibility. The Commission approved the Company's final plan in public deliberations held on September 19, 2024. The statute also allows electric utilities to implement a surcharge not to exceed 2% of customer bills to recover costs to comply with the standard.

Transportation Electrification

The electric transportation market continues to strengthen since 2022. Overall, light duty battery electric vehicle sales have grown since 2022 resulting in a market share of about 9% in the United States[21]. PacifiCorp states, especially west coast states continue to outpace the US market share percentage, California is number one, with Oregon and Washington close behind[22]. By 2030 EVs (LDV) are expected to reach 7.7 million or 46% of sales[23]. EV sales still comprise a small portion of overall sales, however this will shift as medium-duty/heavy-duty (MD/HD) customers continue to expand. PacifiCorp also hosts major interstates and traffic corridors that will see continued electrification through policies discussed above. Furthermore, many businesses are moving to electrify their fleets from port authorities, transit agencies, etc. which will increase load over time.

This rapidly evolving market represents a potential driver of future load growth, and those impacts managed proactively, provide an opportunity to increase the efficiency of the electrical system and provide benefits for all PacifiCorp customers. In addition, increased adoption of electric transportation could improve air quality, reduce noise pollution, reduce greenhouse gas emissions, improve public health and safety, and create financial benefits for drivers, which can be a particular benefit for low- and moderate-income populations.

Current EV adoption numbers indicate that there is still an enormous opportunity for growth in the EV market. To develop a prospective forecast of EV adoption, PacifiCorp developed a model to assess trends for light duty vehicles (LDVs) and medium-duty and heavy-duty vehicles (MD/HDVs). To inform a future vehicle adoption curve, the Company reviewed three national EV

[21] October 2024 auto sales volume to hold steady in the US | S&P Global
[22] Electric vehicle market and policy developments in U.S. states, 2023 - International Council on Clean Transportation
[23] Electric Vehicle Sales and the Charging Infrastructure Required Through 2035

forecasts, each representing varying degrees of aggressiveness. While these forecasts represent national trends, the adoption curves themselves are quite different and can be adjusted to reflect state-specific parameters such as current market conditions, light duty truck saturation, and EV policies adopted in the state. PacifiCorp monitors vehicle adoption in each state on an annual basis and adjusts forecasts accordingly as new data is made available.

To help manage and understand the potential future load growth impacts of electric transportation PacifiCorp is investing to support EV fast chargers along key corridors, develop commercial and residential charging programs, research new rate designs and implement time-of-use pricing programs and managed charging pilots, create partnerships for smart mobility programs and develop opportunities for customers in our rural communities.

In California, Pacific Power's Electric Vehicle Infrastructure Rule 24 will pay for and coordinate the design and deployment of service extensions from our electrical distribution line facilities to the service delivery point for separately metered electric vehicle charging stations.[24] Pacific Power continues to provide programs funded by the Oregon Clean Fuels program as well as the recent HB 2165 legislation passed that created a transportation electrification benefits charge to support infrastructure development in the state of Oregon. As of November 2022, the Washington Utility and Transportation Commission approved Pacific Power's Transportation Electrification Plan which sets out an estimated spend of $3.5 million over the next five years to support TE in Washington state.

In Utah, PacifiCorp is implementing the $50 million Electric Vehicle Infrastructure Program that has four core components: Company-owned public fast chargers, customer incentives, innovative projects, and outreach and education efforts. In June 2024, the first four locations with Company-owned public direct current fast chargers (DCFC) became operational. It is anticipated that there will be roughly 20 locations with an estimated 100 DCFC stations throughout Utah by the end of the program. As of the end of 2023, PacifiCorp had supported installation of over 4,800 EV ports throughout the territory.

Electric vehicle load is reflected in the Company's load forecast. PacifiCorp continues to actively engage with local, regional, and national stakeholders and participate in state regulatory processes that can inform future planning and load forecasting efforts for electric vehicles.

Hydroelectric Relicensing

The issues involved in relicensing hydroelectric facilities are multifaceted. They involve numerous federal and state environmental laws and regulations, and the participation of numerous stakeholders including agencies, Native American tribes, non-governmental organizations, and local communities and governments.

The value of relicensing hydroelectric facilities is continued availability of energy, capacity, and ancillary services associated with hydroelectric generation. Hydroelectric projects can often provide unique operational flexibility because they can be called upon to meet peak customer demands almost instantaneously and back up intermittent renewable resources such as wind and solar with carbon-free generation. In addition to operational flexibility, hydroelectric generation

[24] California Electric Vehicle Infrastructure Line Extensions (pacificpower.net)

does not have the emissions concerns of thermal generation. Hydroelectric projects can also often provide important ancillary services, such as spinning reserve and voltage support, to enhance the reliability of the transmission system.

As of December 31, 2024, PacifiCorp has 15 FERC licensed hydroelectric projects. Each license may contain a single or multiple hydro developments (e.g., dams and powerhouses). PacifiCorp is currently seeking new licenses for the Cutler (30 MW) and Ashton (7.85 MW) hydroelectric projects. A new license for Cutler is expected in 2025, and a new license for Ashton in 2027. The next project to undergo the FERC relicensing process is the Bear River hydroelectric project (77 MW). That project's FERC license expires in 2033.

The FERC hydroelectric relicensing process can be extremely political and often controversial. The process itself requires that the project's impacts on the surrounding environment and natural resources, such as fish and wildlife, be scientifically evaluated, followed by development of proposals and alternatives to mitigate those impacts. Tribal and interested party consultation is conducted throughout the process. If resolution of issues cannot be reached in this process, litigation often ensues, which can be costly and time-consuming. The usual alternative to relicensing is decommissioning. Both choices, however, can involve significant costs.

FERC has sole jurisdiction under the Federal Power Act to issue new operating licenses for non-federal hydroelectric projects on navigable waterways, federal lands, and under other criteria. FERC must find that the project is in the broad public interest. This requires weighing, with "equal consideration," the impacts of the project on fish and wildlife, cultural resources, recreation, land use, and aesthetics against the project's energy production benefits. Because some of the responsible state and federal agencies could place mandatory conditions in the license, FERC is not always in a position to balance the energy and environmental equation. For example, the National Oceanic and Atmospheric Administration Fisheries agency and the U.S. Fish and Wildlife Service have the authority in the relicensing process to require installation of fish passage facilities (fish ladders and screens) and to specify their design. This is often the largest single capital investment that will be considered in relicensing and can significantly impact project economics. Also, because a myriad of other state and federal laws come into play in relicensing, most notably the Endangered Species Act and the Clean Water Act, agencies' interests may compete or conflict with each other, leading to potentially contrary or additive licensing requirements. PacifiCorp has generally taken a proactive approach towards achieving the best possible relicensing outcome for its customers by engaging in negotiations with stakeholders to resolve complex relicensing issues. In some cases, settlement agreements are achieved which are submitted to FERC for incorporation into a new license. FERC welcomes license applications that reflect broad involvement or that incorporate measures agreed upon through multi- party settlement agreements. History demonstrates that with such support, FERC generally accepts proposed new license terms and conditions reflected in settlement agreements.

Potential Impact

Relicensing hydroelectric facilities involves significant process costs. The FERC relicensing process takes a minimum of five years and may take longer, depending on the characteristics of the project, the number of stakeholders, and issues that arise during the process. As of December 31, 2023, PacifiCorp had incurred approximately $33 million in costs for license implementation and ongoing hydroelectric relicensing, which are included in construction work-in-progress on

PacifiCorp's Consolidated Balance Sheet. As current or upcoming relicensing and settlement efforts continue for the Cutler, Ashton and other hydroelectric projects, additional process costs are being or will be incurred that will need to be recovered from customers. Hydroelectric relicensing costs have and will continue to have a significant impact on overall hydroelectric generation cost. Such costs include capital investments and related operations and maintenance costs associated with fish passage facilities, recreational facilities, wildlife protection, water quality, cultural and flood management measures. Project operational and flow-related changes, such as increased in-stream flow requirements to protect aquatic resources, can also directly result in lost generation. Much of these relicensing implementation and settlement costs relate to PacifiCorp's two largest hydroelectric projects: Lewis River and North Umpqua.

Treatment in the IRP

The known or expected operational impacts related to FERC orders and settlement commitments are incorporated in the projection of existing hydroelectric resources discussed in Chapter 7.

PacifiCorp's Approach to Hydroelectric Relicensing

PacifiCorp continues to manage the hydroelectric relicensing process by pursuing interest-based resolutions or negotiated settlements as part of relicensing. PacifiCorp believes this proactive approach, which involves meeting Tribal, agency and others' interests through creative solutions, is the best way to achieve environmental and social improvements while balancing customer costs and risks. PacifiCorp also has reached agreements to decommission projects where that has been the most cost-effective outcome for customers.

Rate Design

Current rate designs in Utah have evolved over time based on orders and direction from the Public Service Commission of Utah and settlement agreements between parties during general rate cases. Most recently, current rates and rate design changes were adopted in Docket No 20-035-04 The goals for rate design are (generally) to reflect the cost to serve customers and to provide price signals to encourage economically efficient usage. This is consistent with resource planning goals that balance consideration of costs, risk, and long-run public policy goals. PacifiCorp currently has several rate design elements that take into consideration these objectives, in particular, rate designs that reflect cost differences for energy or demand during different time periods and that support the goals of acquiring cost-effective energy efficiency.

Residential Rate Design

Residential rates in Utah are comprised of a customer charge and energy charges. The customer charge is a monthly charge that provides limited recovery of customer-related costs incurred to serve customers regardless of usage and is broken into separate charges for residential customers who live in single family and multi-family dwellings All other remaining costs are recovered through volumetric- based energy charges. Energy charges for residential customers are designed with an inclining-tier rate structure so high usage during a billing month is charged a higher rate. Additionally, energy charges are differentiated by season with higher rates in the summer when the costs to serve are higher. Residential customers also have an option for time-of-day rates. Time-of-

day rates have a surcharge for usage during the on-peak periods and a credit for usage during the off-peak periods. This rate structure provides an additional price signal to encourage customers to use less energy during the daily on-peak periods when energy costs are higher. As of December 2023, less than one percent of customers have opted to participate in the time-of-day rate option.

As part of the STEP legislation enacted in SB 115, the company developed a pilot time-of-use program to encourage off-peak charging of electric vehicles for residential customers. The results of this pilot may inform future rate design offerings. Any changes in standard residential rate design or institution of optional rate options to support energy efficiency or time-differentiated usage should be balanced with the recovery of fixed costs to ensure price signals are economically efficient and do not unduly shift costs to other customers.

Commercial and Industrial Rate Design

Commercial and industrial rates in Utah include customer charges, facilities charges, power charges (for usage over 15 kW) and energy charges. As with residential rates, customer charges and facilities charges are generally intended to recover costs that do not vary with energy usage. Power charges are applied to a customer's monthly demand on a kW basis and are intended to recover the costs associated with demand or capacity needs. Energy charges are applied to the customer's metered usage on a kWh basis. All commercial and industrial rates employ seasonal variations in power and/or energy charges with higher rates in the summer months to reflect the higher costs to serve during the summer peak period. Additionally, for customers with load 1,000 kW or more, rates are further differentiated by on-peak and off-peak periods for both power and energy charges. For commercial and industrial customers with load less than 1,000 kW, the company offers an optional time-of-day rates—one that differentiates energy rates for on- and off-peak usage,

Irrigation Rate Design

Irrigation rates in Utah are comprised of an annual customer charge, a monthly customer charge, a seasonal power charge, and energy charges. The annual and monthly customer charges provide some recovery of customer-related costs incurred to serve customers regardless of usage. All other remaining costs are recovered through a seasonal power charge and energy charges. The power charge is for the irrigation season only and is designed to recover demand-related costs and to encourage irrigation customers to control and reduce power consumption. Energy charges for irrigation customers are designed with two options. One is a time-of-day program with higher rates for on-peak consumption than for off-peak consumption. Irrigation customers also have an option to participate in a third-party operated Irrigation Load Control Program. Customers are offered a financial incentive to participate in the program and give the company the right to interrupt service to the participating customers when energy costs are higher.

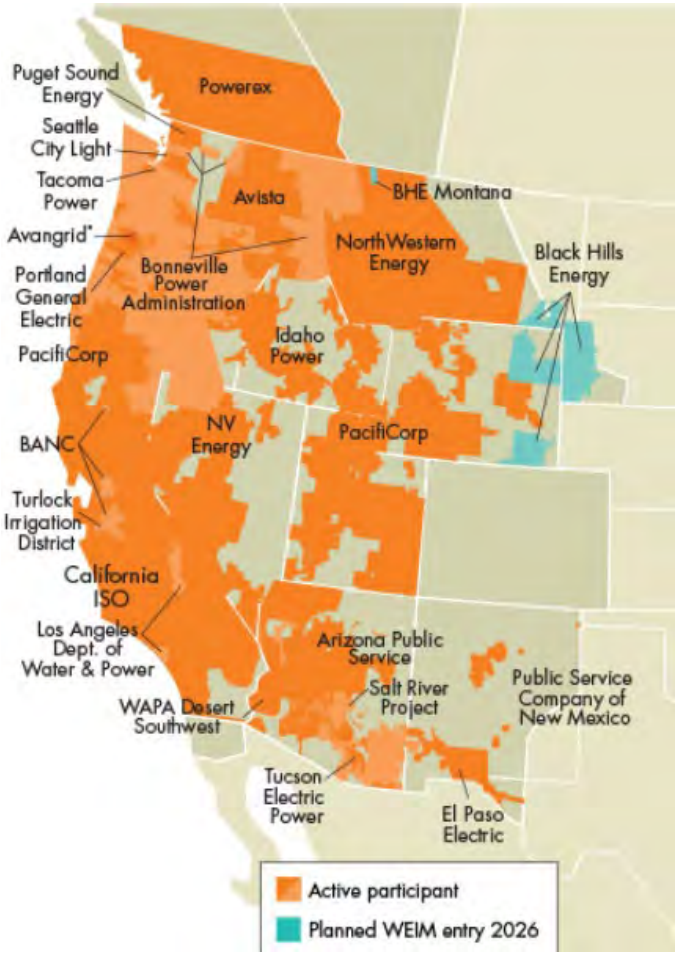
Electricity Market Development Update

PacifiCorp and the CAISO launched the Western Energy Imbalance Market (WEIM) on November 1, 2014. The WEIM is a voluntary market and the first western energy market outside of California. NV Energy (NVE) began participating in December 2015, Arizona Public Service

(APS) and Puget Sound Energy (PSE) began participating in October 2016, and Portland General Electric (PGE) began participating in October 2017. Idaho Power and Powerex began participating in April 2018, and the Balancing Authority of Northern California (BANC)[1] began participating in April 2019. Seattle City Light (SCL) and Salt River Project (SRP) began participating in April 2020, and 2021 saw the addition of NorthWestern Energy, Los Angeles Department of Water & Power (LADWP), Public Service Company of New Mexico (PNM), and Turlock Irrigation District (TID). Avista Utilities, Tucson Electric Power (TEP), Tacoma Power and Bonneville Power Administration (BPA) officially became a participant in the EIM in 2022. El Paso Electric (EPE), Western Area Power Administration Desert Southwest (WAPA DSW) and Avangrid (AVR) entered in April 2023. In 2026, Black Hills Montana and Berkshire Hathaway Energy Montana (BHE Montana) have planned entry into the WEIM.

The WEIM footprint now includes portions of Arizona, California, Idaho, Nevada, Oregon, Texas, New Mexico, Utah, Washington, Wyoming, and British Columbia which make up almost eighty percent of the Western Energy Coordinating Council (WECC) load and will expand to include Montana in 2026. PacifiCorp continues to work with the CAISO, existing and prospective WEIM entities, and stakeholders to enhance market functionality and support market growth.

Figure 3.12 – Western Energy Imbalance Market Expansion



The WEIM has produced approximately $5.85B in monetary benefits since inception for participating utilities, quantified in the following categories: (1) more efficient dispatch, both inter- and intra-regional, by automating dispatch every fifteen and five minutes within and across the WEIM footprint based on the most economical solution; (2) reduced renewable energy curtailment by allowing balancing authority areas to export or reduce imports of renewable generation that would otherwise need to be curtailed; and (3) reduced need for flexible reserves in all WEIM balancing authority areas which reduces cost by aggregating load, wind, and solar variability and forecast errors of the WEIM footprint.

A significant contributor to WEIM benefits is transfers across balancing authority areas, providing access to lower-cost supply, while factoring in the cost of compliance with greenhouse gas emissions regulations that exist in states with a price on carbon (i.e., California and Washington). Generally, transfer quantities are based on transmission and interchange rights between participating balancing authority areas.

After development and expansion of the WEIM in the west, a natural next question was – are there continued opportunities to increase economic efficiency and renewable integration beyond the scope of WEIM but short of a full regional transmission organization? PacifiCorp believes the answer is 'yes'.

Over the duration of 2022, the CAISO held a robust stakeholder process to develop the market design of the Extended Day-Ahead Market (EDAM). With stakeholder feedback, the final EDAM proposal was released in early December 2022. On December 8th, PacifiCorp announced that it intends to join EDAM. The final EDAM design was approved by the CAISO Board of Governors and WEIM Governing Body in early February 2023 and received FERC approval on December 28, 2023. EDAM is scheduled to go live on May 1, 2026, and to date, PacifiCorp and Portland General Electric have signed their EDAM implementation agreements.

The Southwest Power Pool (SPP) has also been developing a day-ahead market offering, called Markets+. Markets+ introduces a potential risk to WEIM benefits through a shrinking WEIM footprint as stakeholders who want to participate in Markets+ would need to exit WEIM. In addition to a smaller WEIM footprint, day-ahead markets with different design elements and requirements for participation exacerbate the seams issue which already exist throughout the west. SPP and stakeholders filed their tariff with FERC on March 29, 2024, and received a deficiency letter on July 31, 2024, that SPP is currently working through to remedy FERC's clarification and additional information request due at the end of November 2024. SPP does not believe the SPP Markets+ timeline will be impacted for their projected spring 2027 go-live target and stakeholders must be vigilant to ensure the markets work as cohesively as possible.

Recent Resource Procurement Activities

PacifiCorp's past procurement efforts have resulted in a number of contracts for new resources that have recently come online or are projected to come online through 2026 as summarized in Table 3.6.[25] These resources are also included in the resource tables presented in Chapter 6.

[25] See Appendix M, stakeholder feedback form #59 (Renewable Northwest)

Table 3.6 – PacifiCorp's Recent and Upcoming New Resource Additions

Resource	Type	Resource Capacity (MW)	Storage Capacity (MW)	Year contracted	Commercial operation	Source
Appaloosa Solar	Solar	200	n/a	2020	Jan 2024	Customer program: UT Sch 34
Rocket Solar	Solar	80	n/a	2020	Feb 2024	Customer program: UT Sch 34
Castle Solar	Solar	40	n/a	2020	Apr 2024	Customer program: UT Sch 32
Horseshoe Solar	Solar	75	n/a	2020	Apr 2024	Customer program: UT Sch 34
Elektron Solar	Solar	80	n/a	2020	Apr 2024	Customer program: UT Sch 34
Oregon Institute of Tech. BESS	Battery Storage	n/a	2	n/a (owned)	Mar 2025	OR HB 2193 (2015)
Rock River Wind	Wind	50	n/a	n/a (owned)	Sep 2024	Repowering of existing site
Cedar Creek Wind	Wind	151.8	n/a	2022	Mar 2024	2020 AS RFP
Anticline Wind	Wind	190	n/a	2022	Dec 2024	2020 AS RFP
Boswell Wind	Wind	100.5	n/a	2022	Dec 2024	2020 AS RFP
Cedar Springs Wind IV	Wind	320	n/a	2022	Jan 2025	2020 AS RFP
Rock Creek Wind I	Wind	350.4	n/a	n/a (owned)	Dec 2024	2020 AS RFP
Rock Creek Wind II	Wind	400	n/a	n/a (owned)	Sep 2025	2020 AS RFP
Green River Energy Center	Solar + Battery	400	400	2022	May 2026	2020 AS RFP: amended to increase storage capacity in 2023
Faraday Solar and Storage	Solar + Battery	525	150	2023	Sep 2025	Customer program: UT Sch 34
Hornshadow Solar	Solar	300	n/a	2023	Jun 2025	Customer program: OR Sch 272
Dominguez Grid	Battery Storage	n/a	200	2024	Jun 2026	Negotiated after 2022 AS RFP
Enterprise Storage	Battery Storage	n/a	80	2024	Jun 2026	Negotiated after 2022 AS RFP
Escalante BESS	Battery Storage	n/a	80	2024	Jun 2026	Negotiated after 2022 AS RFP
Granite Mountain BESS East	Battery Storage	n/a	80	2024	Jun 2026	Negotiated after 2022 AS RFP
Iron Springs BESS	Battery Storage	n/a	80	2024	Jun 2026	Negotiated after 2022 AS RFP
Oregon Comm. Solar (aggregate)	Solar	38.8	n/a	various	various	Oregon Community Solar Program
Total		**3,301**	**1,072**			

PacifiCorp issued and will issue multiple requests for proposals (RFP) to secure resources or transact on various energy and environmental attribute products. Table 3.7 summarizes recent RFP activities.

Table 3.7 – PacifiCorp's Requests for Proposal Activity

RFP	RFP Objective	Status	Issued	Completed
Renewable energy credits (Purchase)	Excess system RECs	Ongoing	Based on specific need	Ongoing
Renewable energy credits (Purchase)	California compliance needs	Ongoing	Based on specific need	Ongoing
Short-term Market (Sales)	System balancing	Ongoing	Based on specific need	Ongoing
2024 Utah Renewables Community RFP	Seeking resources consistent to the Community Clean Energy Act (Utah Code 54-17-901 to -909)	Ongoing	Expected November 2024	Expected October 2025

2022 All-Source RFP

On April 1, 2024, PacifiCorp published the company's 2023 Integrated Resource Plan Update. The 2023 IRP Update preferred portfolio demonstrated that with limited procurement of battery resources in the near-term, which can be achieved outside of a request for proposals process, there is material customer benefit to scaling down and delaying resource acquisition until after 2030. As such, the 2022 All-Source Request for Proposals was terminated. PacifiCorp's 2025 IRP will inform the next steps for incremental resource acquisition.

2024 Utah Renewables Community RFP

The 2024 Utah Renewable Communities' Request for Proposals for renewable energy resources (2024 URC RFP) is administered by the Community Renewable Energy Agency (Agency) on behalf of customers that participate in the Community Clean Energy Program (Program). The 2024 URC RFP is seeking cost-competitive bids for energy produced by wind, photovoltaic (PV) solar, geothermal, or hydroelectric resources and interconnecting with PacifiCorp's transmission system. The Agency is seeking to purchase energy from renewable resources pursuant to the Community Clean Energy Act (Act (Utah Code 54-17-901 to -909)) and in support of the Program created by the Act and the Utah Public Service Commission (Commission).

2025 All-Source RFP

PacifiCorp will seek to file the 2025 All Source RFP ("2025AS RFP") based on results identified in the 2025 IRP preferred portfolio. Further updates on the status and schedule of the 2025AS RFP will be provided as they become available.

Recent Resource Procurement/DSM Procurement

In 2023, PacifiCorp issued a Request for Proposals to re-procure program delivery services for the Home Energy Savings and Wattsmart Business energy efficiency programs in Washington and California. As a result of the re-procurement, new contracts for Washington and California were signed in 2024. For Washington specifically, PacifiCorp followed its Competitive Procurement Framework,[26] including seeking Washington DSM Advisory Group input and posting a notice on the Company website prior to releasing the Request for Proposals. In 2024, PacifiCorp issued a Request for Proposals to re-procure program delivery services for Wattsmart Business in Utah, Idaho and Wyoming, and contracting is underway.

In 2024, PacifiCorp also issued an RFP for energy efficiency implementation services for a commercial new construction program in its Utah service area. The procurement and subsequent contracting steps are still underway.

[26] 2022-2023 Biennial Conservation Plan, Appendix 6 (Docket UE-201830)
The current Competitive Procurement Framework for Washington Conservation and Efficiency Resources is available in Appendix 6 to the 2024-2025 Biennial Conservation Plan (Docket UE-230904).

CHAPTER 4 – TRANSMISSION

CHAPTER HIGHLIGHTS

- PacifiCorp's planned transmission projects help facilitate a transitioning resource portfolio and comply with reliability requirements, while providing sufficient flexibility necessary to ensure existing and future resources can meet customer demand cost effectively and reliably.
- Given the long lead time needed to site, permit, and construct new transmission lines, these projects need to be planned well in advance of resource additions.
- PacifiCorp's transmission planning and benefits evaluation efforts adhere to regulatory and compliance requirements and respond to commission and stakeholder requests for a robust evaluation process and clear criteria for evaluating transmission additions.
- The 2025 IRP preferred portfolio includes the following notable transmission upgrades:[1]
    - A series of upgrades to increase transfer capability between southern Utah and the Wasatch Front, projected to come online between 2026 and 2036.
    - New transmission from the Walla Walla substation near Walla Walla, Washington to the Wine Country substation near Sunnyside, Washington, projected to come online in 2031.
    - 120 miles of new transmission from the Fry substation near Albany, Oregon to a new substation in Deschutes County, Oregon, projected to come online in 2032.
    - New transmission including lines from the Fry substation near Albany, Oregon and from the Dixonville substation near Roseburg, Oregon, each connecting to a substation near Lebanon, Oregon, projected to come online in 2036.
    - A second 416-mile transmission line from the Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah (Energy Gateway South 2), projected to come online in 2036.
- Further, the 2025 IRP preferred portfolio includes near-term transmission upgrades across PacifiCorp's transmission system including investment in infrastructure in Oregon, Utah, and Washington that will facilitate continued and long-term growth in new resources needed to serve PacifiCorp's customers.

Introduction

PacifiCorp's bulk transmission network is a high-value asset that is designed to reliably transport electric energy from a broad array of generation resources (owned or contracted generation including market purchases) to load centers. There are many benefits associated with a robust transmission network, some of which are set forth below:

[1] Two significant transmission projects have been placed in-service since the 2023 IRP, and are therefore included in the 2025 IRP base modeling:

- The Energy Gateway South transmission line - a new 416-mile, high-voltage 500 –kilovolt (kV) transmission line and associated infrastructure running from the Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah. This transmission line was placed in service in Q4-2024.
- The Energy Gateway West Subsegment D1 project - a new high-voltage 230-kilovolt transmission line and a rebuild of an existing 230 kV transmission line from the Shirley Basin substation in southeastern Wyoming to the Windstar substation near Glenrock, Wyoming. These lines were placed in service in Q4-2024.

1. Reliable delivery of diverse energy supply to continuously changing customer demands under a wide variety of system operating conditions.
2. Ability to always meet aggregate electrical demand and customers' energy requirements, considering scheduled outages and the ability to maintain reliability during unscheduled outages.
3. Ability to meet changing regulatory requirements as states move towards a carbon free energy future.
4. Economic dispatch of resources within PacifiCorp's diverse system.
5. Economic transfer of electric power to and from other systems as facilitated by the company's participation in the market, which reduces net power costs and provides opportunities to maintain resource adequacy at a reasonable cost.
6. Access to some of the nation's best wind and solar resources, which provides opportunities to develop geographically diverse low-cost renewable assets.
7. Resiliency to protect against system and market disruptions where limited transmission can otherwise constrain energy supply.
8. Ability to meet obligations and requirements of PacifiCorp's Open Access Transmission Tariff (OATT).

PacifiCorp's transmission network is highly integrated with other transmission systems in the west and provides the critical infrastructure needed to serve our customers cost effectively and reliably. Consequently, PacifiCorp's transmission network is a critical component of the IRP process. PacifiCorp has a long history of providing reliable service in meeting the bulk transmission needs of the region. This valued asset will become even more critical as the regional resource mix transitions to accommodate increasing levels of variable generation from renewable resources that will be used to serve the growing energy needs of our customers.

This chapter provides:

- An overview of PacifiCorp's regulatory requirements including recent updates to PacifiCorp's generation interconnection procedures.
- Support for PacifiCorp's plan to continue permitting the balance of Gateway West;
- Key background information on the evolution of the Energy Gateway Transmission Expansion Plan; and
- An overview of PacifiCorp's investments in recent short-term system improvements that have improved reliability, helped to maximize efficient use of the existing system, and enabled the company to defer the need to invest in larger-scale transmission infrastructure.

Regulatory Requirements

Open Access Transmission Tariff

Consistent with the requirements of its OATT, approved by the Federal Energy Regulatory Commission (FERC), PacifiCorp plans and builds its transmission system based on two customer-type agreements—network customer or point-to-point transmission service. For network customers, PacifiCorp uses ten-year load-and-resource (L&R) forecasts supplied by the customer, as well as network transmission service requests to facilitate development of transmission plans. Each year, PacifiCorp solicits L&R data from each of its network customers to determine future L&R requirements for all transmission network customers. The bulk of PacifiCorp's network customer needs comes from the company's Energy Supply Management (ESM) function, which

supplies energy and capacity for PacifiCorp's retail customers. Other network customers include Utah Associated Municipal Power Systems, Utah Municipal Power Agency, Deseret Power Electric Cooperative (including Moon Lake Electric Association), Bonneville Power Administration (BPA), Basin Electric Power Cooperative, Tri-State Generation & Transmission, the United States Department of the Interior Bureau of Reclamation, and the Western Area Power Administration.

PacifiCorp uses its customers' L&R forecasts and best available information, including transmission service and generation interconnection requests, as factors to determine the need and timing for investments in the transmission system. If customer L&R forecasts change significantly, PacifiCorp may consider alternative deployment scenarios or schedules for transmission system investments, as appropriate. In accordance with FERC guidelines, PacifiCorp is able to reserve transmission network capacity based on this data. PacifiCorp's experience, however, is that the lengthy planning, permitting and construction timeline required to deliver significant transmission investments, as well as the typical useful life of these facilities, is well beyond the 10-year timeframe of L&R forecasts.[2] A 20-year planning horizon and ability to reserve transmission capacity to meet existing and forecasted need over that timeframe is more consistent with the time required to plan for and build large-scale transmission projects, and PacifiCorp supports clear regulatory acknowledgement of this reality and corresponding policy guidance.

For point-to-point transmission service, the OATT requires PacifiCorp to grant service on existing transmission infrastructure using existing capacity or to build transmission system infrastructure as required to provide the service. The required action is determined with each point-to-point transmission service request through FERC-approved study processes that identify the transmission need.

Reliability Standards

PacifiCorp is required to meet mandatory FERC, North American Electric Reliability Corporation (NERC), and Western Electricity Coordinating Council (WECC) reliability standards and planning requirements. The operation of PacifiCorp's transmission system also responds to requests issued by California Independent System Operator (CAISO) RC West as the NERC reliability coordinator. The company conducts annual system assessments to confirm minimum levels of system performance during a wide range of operating conditions, from serving loads with all system elements in service to extreme conditions where portions of the system are out of service. Factored into these assessments are load growth forecasts, operating history, seasonal performance, resource additions or removals, new transmission asset additions, and the largest transmission and generation contingencies. Based on these analyses, PacifiCorp identifies any potential system deficiencies and determines the infrastructure improvements needed to reliably meet customer loads. NERC planning standards define reliability of the interconnected bulk electric system in terms of adequacy and security. Adequacy is the electric system's ability to always meet aggregate electrical demand for customers. Security is the electric system's ability to withstand sudden disturbances or unanticipated loss of system elements. Increasing transmission capacity often requires redundant facilities to meet NERC reliability criteria.

[2] For example, PacifiCorp's application to begin the Environmental Impact Statement process for the Gateway West segment of its Energy Gateway Transmission Expansion Project was filed with the Bureau of Land Management in 2007. A partial Record of Decision (ROD) was received in late April 2013, and a supplemental ROD was received in January 2017.

Generation Interconnection Study Methodology Changes

In 2022 PacifiCorp filed a request with FERC to modify its large generator interconnection procedure to allow PacifiCorp to study new standalone storage resources as not discharging during high generation of other resources in the region. The request was approved by FERC in March 2022 and the new assumptions were implemented into generation interconnection studies starting with Cluster 2. The new operating assumptions have allowed PacifiCorp to use more realistic study assumptions for storage resources which in some circumstances should alleviate the need for additional network upgrades to interconnect new resources.

In 2023 FERC released Order 2023 which required modifications of all transmission provider's including PacifiCorp's, generator interconnection procedures. Several notable changes were included in Order 2023. First, FERC required all transmission providers to move to a first ready, first serve cluster study process which PacifiCorp had already transitioned to in 2020. Second, FERC required all transmission providers to use a distribution factor analysis to assign cost responsibility to specific interconnection customer requests driving the need for network upgrades. This change to PacifiCorp's procedures will allow for projects sited in locations that have smaller impacts on the transmission system, avoiding cost responsibility for upgrades in the region that its project does not cause. Other aspects of the Order 2023 include requiring 100 percent of site control for proposed generating facilities with the initial application and substantial withdrawal penalties at the facilities study stage both of which should disincentivize speculative projects. PacifiCorp will implement a transition process in which existing interconnection requests that have not yet proceeded far enough in the study process will have the opportunity to be studied in a transition cluster study or be withdrawn. PacifiCorp's next application window for new generation interconnection requests will open in 2026.

Aeolus to Mona/Clover (Gateway South – Segment F)

The Energy Gateway South transmission line is a new 416-mile, high-voltage 500-kV transmission line and associated infrastructure running from the Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah. The transmission line is currently under construction and scheduled to come online by the end of 2024.

Windstar-Populus (Gateway West – Segment D)

The Windstar-to-Populus transmission project consists of three key sub-segments:

Figure 4.1 - Segment D

- D1—Recently placed in service, a single-circuit 230-kV line running approximately 59 miles between the existing Windstar and Aeolus substations while looping in and out of Shirley Basin substation in eastern Wyoming.
- D2—A single-circuit 500-kV line completed October 2020 and energized November 2020.
- D3—A single-circuit 500-kV line running approximately 200 miles between the new Anticline substation and the Populus substation in southeast Idaho.

Populus-Hemingway (Gateway West - Segment E)

The Populus-to-Hemingway transmission project consists of two single-circuit 500-kV lines that run approximately 500 miles between the Populus substation in eastern Idaho to the Hemingway substation in western Idaho.

While PacifiCorp is not requesting acknowledgement of a plan to construct these segments in this IRP, the company will continue to permit the projects specifically transmission segment between Midpoint-to-Hemingway portion of Segment E.

Figure 4.2 - Segment E

The Gateway West Segment E project would enable PacifiCorp to more efficiently dispatch system resources, improve performance of the transmission system (i.e., reduce line losses), improve reliability, and enable access to a diverse range of new resource alternatives over the long term.

Plan to Continue Permitting – Gateway West

The Gateway West transmission projects continue to offer benefits under multiple, future resource scenarios. To ensure the company is well positioned to advance the projects, it is prudent for PacifiCorp to continue to permit the balance of Gateway West transmission projects. The record of decision (ROD) and right-of-way grants contain many conditions and stipulations that must be met and accepted before a project can move to construction. PacifiCorp will continue the work necessary to meet these requirements and will continue to meet regularly with the Bureau of Land Management (BLM) to review progress.

Boardman-Hemingway (Segment H)

Boardman-to-Hemingway (B2H) is an approximately 290-mile high-voltage 500-kV transmission line capable of coming online in 2027. PacifiCorp is continuing to coordinate with regional transmission providers and retail customers to evaluate options for this project.

PacifiCorp continues to participate in the project under the Joint Funding Permitting Agreement with Idaho Power. In accordance with this agreement, PacifiCorp is responsible for its share of the costs associated with federal and state permitting activities and other pre-construction activities agreed to in the updated agreement.

Idaho Power's 2023 IRP identified the B2H as a preferred resource to meet its capacity needs, reflecting a need for the project in 2026 to avoid a deficit in load-serving capability in peak-load periods. Given the status of ongoing permitting activities and the construction period, Idaho Power expects the in-service date for the transmission line to be in 2027 or beyond.

The BLM released its record of decision ROD for B2H on November 17, 2017. The ROD allows BLM to grant right-of-way to Idaho Power for the construction, operation, and maintenance of the

B2H Project on BLM-administered land. The BLM right-of-way grant was executed on January 9, 2018.

The U.S. Forest Service (USFS) issued a separate ROD on November 9, 2018, for lands administered by the USFS based on the analysis in the final environmental impact statement. The USFS ROD approves the issuance of a special-use authorization for a portion of the project that crosses the Wallowa-Whitman National Forest. The U.S. Department of the Navy issued a ROD on September 25, 2019, in support of construction of a portion of the B2H project on 7.1-miles of the Naval Weapons Systems Training Facility in Boardman, Oregon.

On September 27, 2022, Oregon's Energy Facility Siting Council approved the Oregon site certificate completing Oregon's permit actions that provide for the construction of the project across private lands in Oregon. Following this action an appeal was made to the Oregon Supreme court challenging the approval. On March 8, 2023, the court affirmed the site certificate which finalized the site certificate.

In January of 2022 Idaho Power, BPA and PacifiCorp agreed in a non-binding term sheet to negotiate Bonneville's exit of the project with Idaho Power acquiring Bonneville's share responsibility of the project. This will provide Idaho Power with a 45 percent share of the project and retain PacifiCorp's 55 percent share. Additional terms under negotiations include changes in transmission service between PacifiCorp and BPA, between BPA and Idaho Power, as well as the purchase and sale of certain assets between Idaho Power and PacifiCorp. The Boardman to Hemingway amended Permit Funding Agreement removing Bonneville and updating the agreement to capture additional pre-construction tasks was executed on March 23, 2023. The Joint Purchase and Sale agreement between Idaho Power and PacifiCorp provides Idaho Power with certain assets allowing service to BPA customers in southeast Idaho via the B2H line, and capacity from the Four Corners substation in New Mexico to the Populus substation in southern Idaho. Associated with the term sheet is the Hemingway project construction agreement, construction agreements for upgrades that provide PacifiCorp additional capacity across Idaho Power's transmission system and a construction agreement that provides PacifiCorp additional capacity to serve central Oregon loads. These agreements were all executed on March 23, 2023.

Idaho Power has applied for Certificates of Public Convenance and Necessity (CPCN) in Oregon and Idaho. Issuance of both certificates were received in June of 2023. PacifiCorp received a CPCN in Idaho in June 2023 and in Wyoming in August 2023.

The current project schedule includes projected completion in 2027.

At this time, PacifiCorp is reevaluating the timing and needs analysis underlying B2H because of factors such as changed native load growth and a lack of capacity available on neighboring transmission systems to deliver to load pockets.

Spanish Fork – Mercer 345-kV line

The 2025 preferred portfolio includes the construction of a new, approximately 50-mile, 345-kV transmission line between Spanish Fork Substation and Mercer substation in Utah, with an identified in-service date of 2036, based on projected interconnection requirements. Load-service and reliability requirements may bring this date forward, as could accelerated generator

interconnection demand. PacifiCorp has begun the permitting process for this new transmission line and is currently targeting an in-service date of 2027 for the line.

Other Transmission System Improvements

The 2025 IRP preferred portfolio also includes near-term transmission upgrades across its transmission system. Ongoing investment in transmission infrastructure in Idaho, Oregon, Utah, Washington, and Wyoming will facilitate continued and long-term growth in new renewable resources and increased reliability for its customers.

Energy Gateway Transmission Expansion Plan

Introduction

Given the long–lead time required to successfully site, permit, and construct major new transmission lines, these projects need to be planned well in advance. The Energy Gateway Transmission Expansion Plan is the result of several robust local and regional transmission planning efforts that are ongoing and have been conducted multiple times over a period of several years. The purpose of this section is to provide important background information on the transmission planning efforts that led to PacifiCorp's proposal of the Energy Gateway Transmission Expansion Plan.

Background

Until PacifiCorp's announcement of Energy Gateway in 2007, its transmission planning efforts traditionally centered on new resource additions identified in the IRP. With timelines of seven to ten years or more required to site, permit, and build transmission, this traditional planning approach was proving to be problematic, leading to a perpetual state of transmission planning and new transmission capacity not being available in time to be viable for meeting customer needs. The existing transmission system has been at capacity for several years, and new capability is necessary to enable new resource development.

The Energy Gateway Transmission Expansion Plan, formally announced in May 2007, has origins in numerous local and regional transmission planning efforts discussed further below. Energy Gateway was designed to ensure a reliable, adequate system capable of meeting current and future customer needs. Importantly, given the changing resource picture, its design supports multiple future resource scenarios by connecting resource-rich areas and major load centers across PacifiCorp's multi-state service area. In addition, the ability to use these resource-rich areas helps position PacifiCorp to meet current state renewable portfolio requirements and other state-specific policy goals. Energy Gateway has since been included in all relevant local, regional and interconnection-wide transmission studies.

Planning Initiatives

Energy Gateway is the result of robust local and regional transmission planning efforts. PacifiCorp has participated in numerous transmission planning initiatives, both leading up to and since Energy Gateway's announcement. Stakeholder involvement has played an important role in each of these initiatives, including participation from state and federal regulators, government agencies, private and public energy providers, independent developers, consumer advocates, renewable energy

groups, policy think tanks, environmental groups, and elected officials. These studies have shown a critical need to alleviate transmission congestion and move constrained energy resources to regional load centers throughout the west, and include:

- **Rocky Mountain Area Transmission Study**
  Recommended transmission expansions overlap significantly with Energy Gateway configuration, including:
  - Bridger system expansion is like Gateway West.
  - Southeast Idaho to southwest Utah expansion akin to Gateway Central, Segment B, Segment C and Sigurd to Red Butte (in service 2015).
  - Improved east-west connectivity like Energy Gateway Segment H alternatives.

> "The analyses presented in this Report suggest that well-considered transmission upgrades, capable of giving LSEs greater access to lower cost generation and enhancing fuel diversity, are cost-effective for consumers under a variety of reasonable assumptions about natural gas prices."

- **Western Governors' Association Transmission Task Force Report**
  Examined the transmission needed to deliver the largely remote generation resources contemplated by the Clean and Diversified Energy Advisory Committee. This effort built upon the transmission previously modeled by the Seams Steering Group-Western Interconnection and included transmission necessary to support a range of resource scenarios, including high efficiency, high renewables and high conventional resource scenarios. Again, for PacifiCorp's system, the transmission expansion that supported these scenarios closely resembled Energy Gateway's configuration.

> "The Task Force observes that transmission investments typically continue to provide value even as network conditions change. For example, transmission originally built to the site of a now obsolete power plant continues to be used since a new power plant is often constructed at the same location."

- **NorthernGrid Regional Transmission Plan Reports**
  In the 2020-2021 NorthernGrid Regional Transmission Plan, sub segments of Energy Gateway (both Gateway West and Gateway South) were listed as necessary to provide acceptable system performance. The study also established that the amount of new Wyoming wind generation that is added over time can impact the transmission system reliability west of Wyoming. Additionally, three interregional projects were included in the study: the Southwest Inter-tie Project (SWIP North), Cross Tie and TransWest Express, which showed that all three projects relied on Energy Gateway to attain their full transfer capability rating.

> "After analyzing the steady-state performance of stressed conditioned cases, a rigorous contingency analysis commenced… then, NTTG's Technical Committee determined additional facilities would be needed to meet the reliability criteria…."

The NorthernGrid 2022-2023 Regional Transmission Plan identified the regional combination consisting of Gateway West (Segment D.3 and Segment E) and B2H as the most efficient and cost-effective set of projects for the NorthernGrid 10-year planning horizon. Gateway South was considered as an in-service project in all cases, including the selected regional combination.

- **WECC/Reliability Assessment Committee (RAC) Annual Reports and Western Interconnection Transmission Path Utilization Studies**
  These analyses measure the historical use of transmission paths in the west to provide insight into where congestion is occurring and assess the cost of that congestion. The Energy Gateway segments were included in the analyses that support these studies, alleviating several points of significant congestion on the system, including Path 19 (Bridger West) and Path 20 (Path C).

> "Path 19 [Bridger] is the most heavily loaded WECC path in the study…. Usage on this path is currently of interest due to the high number of requests for transmission service to move renewable power to the West from the Wyoming area."

Energy Gateway Configuration

To address constraints identified on PacifiCorp's transmission system, as well as meeting system reliability requirements discussed further below, the recommended bulk electric transmission additions took on a consistent footprint, which is now known as Energy Gateway. This expansion plan establishes a triangle of reliability that spans Utah, Idaho and Wyoming with paths extending into Oregon and Washington. This plan contemplates geographically diverse resource locations based on environmental constraints, economic generation resources, and federal and state energy policies.

Since Energy Gateway's initial announcement in 2007, this series of projects has continued to be vetted through multiple public transmission planning forums at the local, regional and Western Interconnection level. In accordance with the local planning requirements in PacifiCorp's OATT, Attachment K, PacifiCorp has conducted numerous public meetings on Energy Gateway and transmission planning in general. Meeting notices and materials are posted publicly on PacifiCorp's Attachment K Open Access Same-time Information System (OASIS) site. PacifiCorp is also a member of NorthernGrid regional planning organization and WECC's Reliability Assessment Committee and was formally a member of Northern Tier Transmission Group (NTTG) regional planning organization.

These groups continually evaluate PacifiCorp's transmission plan in their efforts to develop and refine the optimal regional and interconnection-wide plans. Please refer to PacifiCorp's OASIS site for information and materials related to these public processes.[3]

Additionally, an extensive 18-month stakeholder process on Gateway West and Gateway South was conducted. This stakeholder process was conducted in accordance with WECC Regional Planning Project Review guidelines and FERC OATT planning principles, and was used to

[3] http://www.oatioasis.com/ppw/index.html

establish need, assess benefits to the region, vet alternatives, and eliminate duplication of projects. Meeting materials and related reports can be found on PacifiCorp's Energy Gateway OASIS site.

Energy Gateway's Continued Evolution

The Energy Gateway Transmission Expansion Plan is the product of years of ongoing local and regional transmission planning efforts with significant customer and stakeholder involvement. Since its announcement in May 2007, Energy Gateway's scope and scale have continued to evolve to meet the future needs of PacifiCorp customers and the requirements of mandatory transmission planning standards and criteria. Additionally, PacifiCorp has improved its ability to meet near-term customer needs through a limited number of smaller-scale investments that maximize efficient use of the current system and help defer, to some degree, the need for larger capital investments like Energy Gateway (see the following section titled "Efforts to Maximize Existing System Capability"). The IRP process, as compared to transmission planning, can result in frequent changes in the least-cost, least-risk resource plan driven by changes in the planning environment (i.e., market conditions, cost and performance of new resource technologies, etc.). Near-term fluctuations in the resource plan do not always support the longer-term development needs of transmission infrastructure, or the ability to invest in transmission assets in time to meet customer needs. Together, however, the IRP and transmission planning processes complement each other by helping PacifiCorp optimize the timing of its transmission and resource investments to deliver cost-effective and reliable energy to our customers.

While the core tenets for Energy Gateway's design have not changed, the project configuration and timing continue to be reviewed and modified to coincide with the latest mandatory transmission system reliability standards and performance requirements, annual system reliability assessments, input from several years of federal and state permitting processes, and changes in generation resource planning and our customers' forecasted demand for energy.

As originally announced in May 2007, Energy Gateway consisted of a combination of single- and double-circuit 230 kV, 345 kV and 500 kV lines connecting Wyoming, Idaho, Utah, Oregon and Nevada. In response to regulatory and industry input regarding potential regional benefits of "upsizing" the project capacity (for example, maximized use of energy corridors, reduced environmental impacts and improved economies of scale), PacifiCorp included in its original plan the potential for doubling the project's capacity to accommodate third-party and equity partnership interests. During late 2007 and early 2008, PacifiCorp received more than 6,000 MW of requests for incremental transmission service across the Energy Gateway footprint, which supported the upsized configuration. PacifiCorp identified the costs required for this upsized system and offered transmission service contracts to queue customers. These queue customers, however, were unable to commit due to the upfront costs and lack of firm contracts with end-use customers to take delivery of future generation and withdrew their requests. In parallel, PacifiCorp pursued several potential partnerships with other transmission developers and entities with transmission proposals in the Intermountain Region. Due to the significant upfront costs inherent in transmission investments, firm partnership commitments also failed to materialize, leading PacifiCorp to pursue the current configuration with the intent of only developing system capacity sufficient to meet the long-term needs of its customers.

In 2010, PacifiCorp entered memorandums of understanding (MOU) to explore potential joint-development opportunities with Idaho Power Company on its Boardman-to-Hemingway (B2H) project and with Portland General Electric Company (PGE) on its Cascade Crossing project. One of the key purposes of Energy Gateway is to better integrate PacifiCorp's east and west balancing

authority areas, and Gateway Segment H from western Idaho into southern Oregon was originally proposed to satisfy this need. However, recognizing the potential mutual benefits and value for customers of jointly developing transmission, PacifiCorp has pursued these potential partnership opportunities as a potential lower-cost alternative.

In 2011, PacifiCorp announced the indefinite postponement of the Gateway South 500 kV segment between the Mona substation in central Utah and Crystal substation in Nevada. This extension of Gateway South, like the double-circuit configuration discussed above, was a component of the upsized system to address regional needs if supported by queue customers or partnerships. However, despite significant third-party interest in the Gateway South segment to Nevada, there was a lack of financial commitment needed to support the upsized configuration.

In 2012, PacifiCorp determined that one new 230 kV line between the Windstar and Aeolus substations and a rebuild of the existing 230 kV line were feasible, and that the second new proposed 230 kV line and proposed 500 kV line planned between Windstar and Aeolus would be eliminated. This decision resulted from PacifiCorp's ongoing focus on meeting customer needs, taking stakeholder feedback and land-use limitations into consideration, and finding the best balance between cost and risk for customers. In January 2012, PacifiCorp signed the B2H Permitting Agreement with Idaho Power Company and BPA that provides for PacifiCorp's participation through the permitting phase of the project. The B2H project was pursued as an alternative to PacifiCorp's originally proposed transmission segment from eastern Idaho into southern Oregon (Hemingway to Captain Jack). Idaho Power leads the permitting efforts on the B2H project, and PacifiCorp continues to support these activities under the conditions of the B2H Transmission Project Joint Permit Funding Agreement. The proposed line provides additional connectivity between PacifiCorp's west and east balancing authority areas and supports the full projected line rating for the Gateway projects at full build out. PacifiCorp plans to continue to support the project under the Permit Funding Agreement and will assess next steps post-permitting based on customer need and possible benefits.

In January 2013, PacifiCorp began discussions with PGE regarding changes to its Cascade Crossing transmission project and potential opportunities for joint development or firm capacity rights on PacifiCorp's Oregon system. PacifiCorp further notes that it had a memorandum of understanding with PGE for the development of Cascade Crossing that was terminated by its own terms. PacifiCorp had continued to evaluate potential partnership opportunities with PGE once it announced its intention to pursue Cascade Crossing with BPA. However, because PGE decided to end discussions with BPA and instead pursue other options, PacifiCorp is not actively pursuing this opportunity. PacifiCorp continues to look to partner with third parties on transmission development as opportunities arise.

In May 2013, PacifiCorp completed and placed in service the Mona-to-Oquirrh project. In November 2013, the BLM issued a partial ROD providing a right-of-way grant for all of Segment D and most of Segment E of Energy Gateway. The agency chose to defer its decision on the western-most portion of Segment E of the project located in Idaho to perform additional review of the Morley Nelson Snake River Birds of Prey Conservation Area. Specifically, the sections of Gateway West that were deferred for a later ROD include the sections of Segment E from Midpoint to Hemingway and Cedar Hill to Hemingway.

In May 2015, the Sigurd-to-Red Butte project was completed and placed in service.

In December 2016, the BLM issued its ROD and right-of-way grant for the Gateway South project.

In January 2017, the BLM issued its ROD and right-of-way grant, previously deferred as part of the November 2013 partial ROD, for the sections of Segment E from Midpoint to Hemingway and Cedar Hill to Hemingway.

In October 2020, Segment D2 of Gateway West, from Aeolus to Jim Bridger was placed into service which included a new 500 kV substation at Aeolus, and a new 345 kV substation at Anticline.

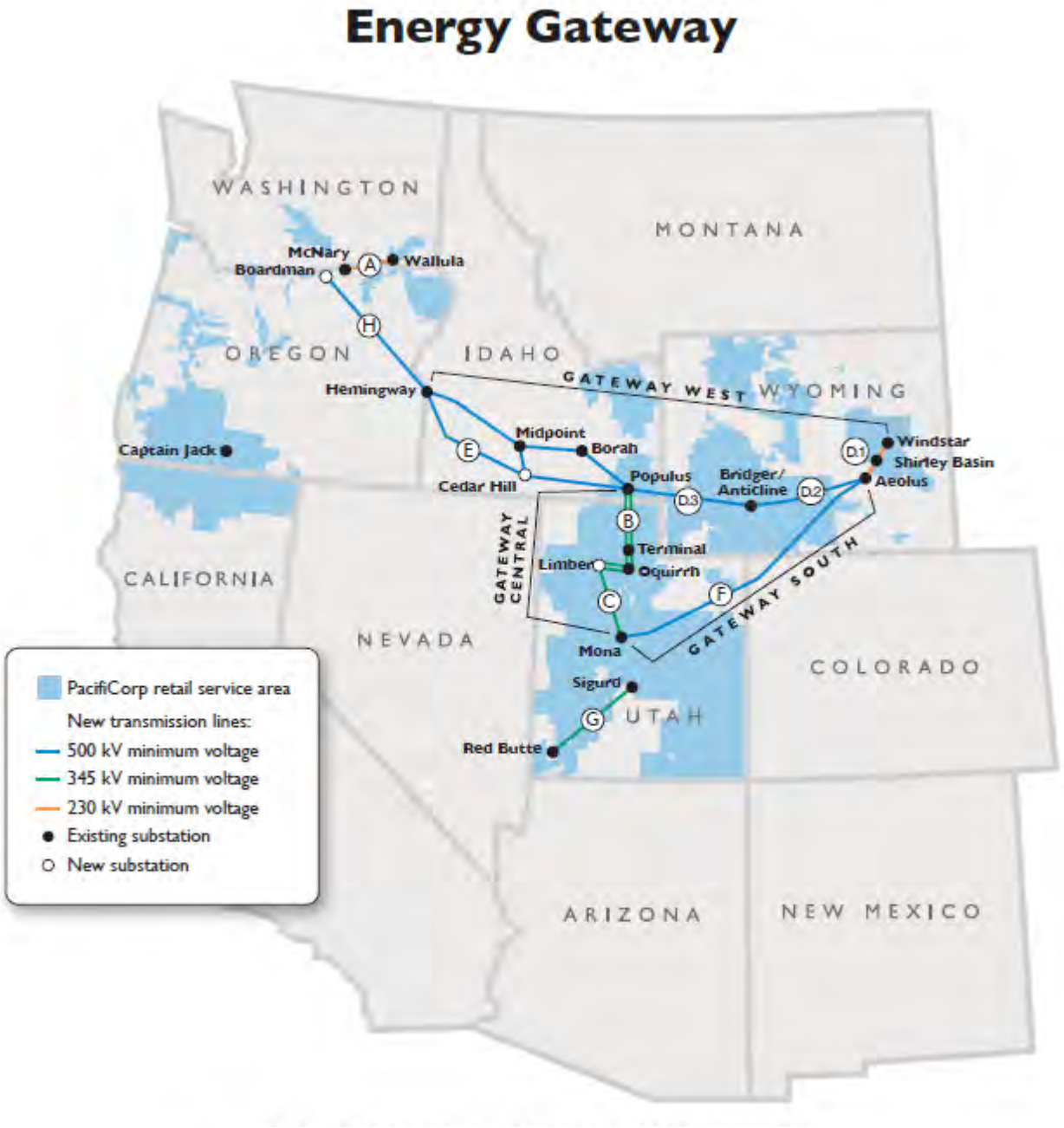
In October 2020, a portion of Gateway West Segment D1, the 230 kV line between Aeolus and Shirley Basin was also constructed and completed in 2020. The remaining portion of Gateway West, Segment D1, consisting of a new 230 kV line between Shirley Basin and Windstar substations and a rebuild of an existing 230 kV line between Shirley Basin and Dave Johnston substations is under construction with an expected completion date of both lines in December 2024.

Gateway Segment F, referred to as Gateway South, a 416-mile 500 kV line from Aeolus substation in Wyoming to Mona/Clover substation in central Utah is under construction with an expected completion date of December 2024.

Other Gateway segments, including Gateway West Segment D3 from Bridger substation in Wyoming to Populus substation in Idaho and Gateway West Segment E from Populus to Hemingway, in Idaho, are in pre-construction activities to address requirements as defined in their permitting Record of Decision and right-of-way grants issued by the BLM.

PacifiCorp will continue to adjust the timing and configuration of its proposed transmission investments based on its ongoing assessment of the system's ability to meet customer needs, its compliance with mandatory reliability standards, and the stipulations in its project permits.

Figure 4.3 – Energy Gateway Transmission Expansion Plan



This map is for general reference only and reflects current plans.
It may not reflect the final routes, construction sequence or exact line configuration.
PacifiCorp is reevaluating the timing and needs analysis underlying B2H because of factors such as changed native load growth and a lack of capacity available on neighboring transmission systems to deliver to load pockets.

Table 4.1 – Energy Gateway Transmission Expansion Plan

Segment & Name	Description	Approximate Mileage	Status and Scheduled In-Service
(A) Wallula-McNary	230 kV, single circuit	30 mi	• Status: completed • Placed in-service: January 2019
(B) Populus-Terminal	345 kV, double circuit	135 mi	• Status: completed • Placed in-service: November 2010
(C) Mona-Oquirrh	500 kV single circuit 345 kV double circuit	100 mi	• Status: completed • Placed in-service: May 2013
Oquirrh-Terminal	345 kV double circuit	14 mi	• Status: right-of-way acquisition underway • Scheduled in-service: 2024
(D1) Windstar-Aeolus	New 230 kV single circuit Re-built 230 kV single circuit	59 mi	• Status: permitting underway • Scheduled in-service: December 2024
(D2) Aeolus-Bridger/Anticline	500 kV single circuit	140 mi	• Status: completed • Placed in-service: November 2020
(D3) Bridger/Anticline-Populus	500 kV single circuit	200 mi	• Status: permitting underway • Scheduled in-service: 2034 earliest
(E) Populus-Hemingway	500 kV single circuit	500 mi	• Status: permitting underway • Scheduled in service: 2036 earliest
(F) Aeolus-Mona	500 kV single circuit	416 mi	• Status: permitting underway • Scheduled in-service: December 2024
(G) Sigurd-Red Butte	345 kV single circuit	170 mi	• Status: completed • Placed in-service: May 2015
(H) Boardman-Hemingway	500 kV single circuit	290 mi	• Status: pre-construction activities in progress • Scheduled in-service: 2027

Efforts to Maximize Existing System Capability

In addition to investing in the Energy Gateway transmission projects, PacifiCorp continues to make other system improvements that have helped maximize efficient use of the existing transmission system and defer the need for larger-scale, longer-term infrastructure investment. Despite limited new transmission capacity being added to the system over the last 20 to 30 years, PacifiCorp has maintained system reliability and maximized system efficiency through other smaller-scale, incremental projects.

System-wide, PacifiCorp has instituted more than 130 grid operating procedures and 20 remedial action schemes (RAS) to maximize the existing system capability while managing system risk. In addition, PacifiCorp has been an active participant in the Energy Imbalance Market (EIM) since November 2014. As of April 2023, 22 participants have joined the EIM. By broadening the pool of lower-cost resources that can be accessed to balance load system requirements, enhances reliability and reduces costs across the entire EIM Area. In addition, the automated system can identify and use available transmission capacity to transfer the dispatched resources, enabling more efficient use of the available transmission system.

To secure further benefits from market-based resource dispatch, PacifiCorp announced in December 2022 that it expects to participate in the Extended Day-Ahead Market (EDAM) being

developed by the California Independent System Operator (CAISO).[4] While the EIM makes full use of resource flexibility within the hour and will continue to do so, the EDAM will provide economic, reliability, and environmental benefits by optimizing the pool of resources that are made available to EIM in light of forecasted requirements for the entire market footprint over the following several days, well beyond the end of the current hour. This includes coordination of generator starts and shutdowns and the charging and discharging of energy storage resources.

Transmission System Improvements Placed In-Service Since the 2023 IRP

PacifiCorp East (PACE) Control Area

1. Central Wyoming Area
    - Installs a 345 kV, 200-MVAr switched shunt reactor at Mona substation:
        - Project driver was to address the high voltage conditions experienced during steady state operations under light load and light transfer conditions.
        - Benefits include more effective high voltage control and safe and more reliable power for the Utah area by reducing lines taken out of service and preservation of substation equipment life, particularly circuit breakers which are exposed to frequent switching, reduced probability of mis operation and increased maintenance costs.
2. Northern Utah/Southeast Idaho Area
    - Constructed a new 345 kV yard adjacent to the existing Bridgerland 138 kV substation. Looped in the existing Populus – Terminal 345 kV line into Bridgerland and Ben Lomond substations:
        - Project driver was to resolve System Operating Limit on Path C.
        - Benefits include the ability to maintain the WECC Path C rating to 1600 MW southbound and 1250 MW northbound.
3. Salt Lake City Utah area
    - Install two capacitor banks at Magna Substation and rebuild the Tooele – Pine Canyon 138 kV transmission line:
        - Project driver was to correct N-1 contingency overload and low voltage issues at Magna substation and on the Tooele – Pine Canyon 138 kV line from consistent load growth and new block loads.
        - Benefits included mitigating the risk of thermal overloads and low voltage issues, adding additional capacity to address projected load growth and improve transmission reliability.
4. Southern Utah area
    - Reconductor 2.57-miles of the St. George-Purgatory Flat 138 kV transmission line:
        - Project driver was to increase the thermal rating of the line which loaded to 95 percent of its continuous summer thermal rating summer 2022.
        - Benefits included the increases of the transmission line summer continuous rating by 63 MVA.

[4] http://www.caiso.com/Documents/EDAM-Fact-Sheet.pdf

PacifiCorp West (PACW) Control Area

1. Klamath Falls Oregon Area
    - Constructed a second 230 kV transmission line from Snow Goose to Klamath Falls substation:
        - Project driver was to resolve NERC Standard TPL-001-5 Category P6 (N-1-1) for a double contingencies on the 230-kV system serving Yreka, Klamath Falls and La Pine area for the loss of the Klamath Falls-Snow Goose 230 kV line and either the Lone Pine-Copco 230 kV line or Bonneville Power Administration's (BPA) Pilot Butte-La Pine 230 kV line can cause a voltage collapse affecting a large region of the southern Oregon and northern California system.
        - Benefits included reinforcing 230 kV system between in Klamath Falls area to cover TPL-001-5 category P6 (N-1-1) contingencies during all operating conditions on the existing system and minimize risk of a large-scale outage to customers throughout the Klamath Falls and Yreka areas.
2. Prineville Oregon Area
    - Construct a second 115 kV line between Houston Lake and Ponderosa substations:
        - Project driver was to eliminates potential N-1 overloads of the Prineville 115 kV system associated with increased load, changing generation mix, and grid flow conditions in the area.
        - Benefits included the elimination of a NERC Standard TPL-001-5 Category P1 contingency event for a fault on the 115 kV line between Baldwin Road and Ponderosa substation or a fault on the 115 kV line between Houston Lake and Stearns Butte.

Planned Transmission System Improvements

PacifiCorp East (PACE) Control Area

1. Central Utah Area
    - Upgrade the 345-138 kV 167-MVA transformer at Camp Williams substation to a 345-138 kV 700-MVA transformer:
        - Project driver is to correct NERC Standard TPL-001-5 Category P6 deficiencies during peak summer loading conditions for the N-1-1 event of losing both Spanish Fork substation 345-138 kV transformers that would cause thermal overloads to the Camp Williams 345-138 kV transformer and the Clover – Nebo 138 kV line.
        - Benefits include mitigating the NERC Standard TPL-001-5 Category P6 deficiencies. Provides additional 345 kV source to northern Utah Valley and Jordan Valley as well as increase system reliability.
    - Install a second 345-138 kV 700 MVA transformer at Oquirrh substation:
        - Project driver is to correct N-1 contingency overload issues in the South Jordan area.

- Benefits include increasing capacity on the 138 kV network serving the Salt Lake Valley.

- Construct a new 345 kV line between Spanish Fork and Mercer 345 kV substations:
  - Project driver is to eliminate the need for the Lakeside II Remedial Action Scheme (RAS) and prevent generation shedding during contingencies. Once flows across the Wasatch Front South boundary exceed 5,562 MW, the Lakeside RAS is no longer effective and cannot be modified to accommodate more flow.
  - Benefits include the increase of path limit to 6,300 MW and allow 1,000 MW additional generation to be interconnected in southern Utah.

2. Utah, Idaho & Wyoming - Upgrade Program – Replace Over-dutied Circuit Breakers:
   - Replaced breakers identified as over-dutied with higher-capability breakers in various substations located in Idaho, Utah, and Wyoming:
     - Project driver was to correct NERC Standard TPL-001-5 Requirement R2.3 deficiencies identified in PacifiCorp's 2015-2018 NERC TPL Assessment resulting in the identification of 12 substations to be addressed as required per R2.8.
     - Benefits include eliminating the risk of over-dutied breakers failing under fault interruption conditions that pose safety and reliability risks, and the resolution of the NERC TPL-001-5 Requirement R2.3 deficiencies and as required per R2.8.
3. Salt Lake City, Utah Area:
   - Convert North Salt Lake Substation to 138-kV:
     - Project driver is to correct N-1 contingency overload issues in the North Salt Lake area.
     - Converting to 138 kV at North Salt Lake substation increases the capacity in the area while mitigating the contingency overloads, reduces the burden on the 46 kV system, and brings better reliability to the customers in the area.
   - Loop the 90th South – Terminal 345 kV line into and out of the Midvalley 345 kV yard:
     - Project Driver is to eliminate identified overloading of the 90th South – Midvalley 345 kV #1 line under heavy transfer conditions across the Wasatch Front South boundary.
     - Benefits include increasing the transfer capability across the Wasatch Front South boundary by 45-MW, improving operating flexibility, and allowing additional transfers from Clover/Mona as well as from southern Utah to the Wasatch Front.
   - Construct a new 230-46 kV substation near Eden, Utah:
     - Project driver is to provide a transmission loop to the area to facilitate a line rebuild through Ogden Canyon.
     - Benefits include improved future reliability and area capacity.
4. Southeast Idaho Area:
   - Install a 25 MVAR shunt capacitor bank at the Franklin 138 kV substation:
     - Project driver is to correct NERC Standard TPL-001-5 Category P1 (N-1) contingency events for the loss of the Treasureton – Franklin 138 kV line.

- Benefits include resolving the NERC Standard TPL-001-5 Category P1 voltage issues.

PacifiCorp West (PACW) Control Area

1. Eastern Oregon Area
   - Replace the entire Burns 500 kV reactive station, including the series capacitor bank, bypass breakers, shunt reactors, and all switches and circuit switchers:
     - Project driver is to replace obsolete and degrading assets to prevent equipment failure which would result in a substantial financial impact and limiting Jim Bridger and Wyoming wind generation for an extended time.
     - Benefits include replacement of obsolete equipment with modern SCADA-operable equipment (reducing operational labor), reduces the risk of failure, and improves recovery time.
2. Portland Oregon Area
   - Reconfigure and convert the existing Bonneville Power Administration's (BPA) St. Johns – Columbia and PacifiCorp's (PAC) Columbia – Knott 57 kV lines, and a portion of the idle 69 kV line north of Albina to 115 kV:
     - Project driver is to correct NERC Standard TPL-001-5 Category P6 (N-1-1) deficiencies for load loss of up to 62-MW in the urban northeast Portland core area and Category P6 (N-1-1) deficiencies for voltage issues on the 57 kV system.
     - Benefits include resolution of NERC Standard TPL-001-5 Category P6 (N-1-1) deficiencies, elimination of the 57 kV system voltage in the North Portland and creates a third 115 kV path between the St. Johns/Rivergate and the Knott/Albina area.
3. Roseburg Oregon Area
   - Convert the 69 kV transmission Lines 30 and 65 to 115 kV, along with four distribution substations and construct a new 115 kV tie from Roberts Creek to the converted Green substation:
     - Project driver is to resolve multiple capacity limitations in the area; notably the Roberts Creek 115-69 kV transformer, the Winchester 115-69 kV transformer, Line 66 between Dixonville and Sutherlin and Line 65 between Dixonville and Southgate. 12 system problems were identified as being affected by these limitations.
     - Benefits include improvement of operability of the system to increase reliability during outages and maintenance and gives the system enough excess capacity to accommodate 20 years of growth at a 1.3 percent per year rate.
   - Replace the existing 230-115 kV transformer at Dixonville substation with a new 280 MVA transformer:
     - Project driver is to resolve excess voltage on the 115 kV bus. The current transformer steady state voltage sits at 10.4 percent above nominal in the North Umpqua Hydroelectric System and is nearly 8.7 percent above nominal at Dixonville substation.
     - Benefit includes bringing the 115 kV bus voltage at Dixonville to operate within an acceptable range and avoids excessive voltage throughout the Roseburg and North

Umpqua areas extending the life of the transformers as well as all the downstream equipment.

4. Medford Oregon Area

- Construct a 230-kV transmission line between Lone Pine and Whetstone substations:
  - Project driver is to correct NERC Standard TPL-001-5 Category P1 (N-1) and P6 (N-1-1) outage combinations including loss of the two Meridian-Lone Pine 230-kV lines (N-1), N-1-1 loss of the Meridian-Whetstone and Dixonville-Grants Pass 230-kV lines, or N-1-1 loss of Sams Valley 500-230 kV source and either the Meridian-Whetstone 230-kV line or Dixonville-Grants Pass 230-kV line.
  - Benefits include resolving the NERC Standard TPL-001-5 Category P1 and P6 issues as well as preventing reverse flow across the Medford 115 kV system to support the 230 kV system and allows operating the Medford 115 kV system radial.
- Construct one new 500-230 kV substation called Sams Valley:
  - Project driver is to correct NERC Standard TPL-001-5 deficiencies for the loss of a single 230 kV line and for N-1-1 and N-2 outages to 230 kV lines that were initially identified in PacifiCorp's 2010 NERC TPL Assessment and supported through subsequent NERC TPL Assessments, and to provide a second 500 kV source to address load growth in the Southern Oregon region.
  - Benefits include adding a second source of 500 kV capacity, adding a new 230-kV line, improving reliability of the 230 kV network, mitigates the risk of thermal overloads and low voltage, mitigates the risk of shedding load in preparation of the second contingency for N-1-1 outages, and resolves the NERC TPL-001-5 deficiencies.

These investments help maximize the existing system's capability, improve PacifiCorp's ability to serve growing customer loads, improve reliability, increase transfer capacity across WECC Paths, reduce the risk of voltage collapse and maintain compliance with North American Electric Reliability Corporation and Western Electricity Coordinating Council reliability standards.

CHAPTER 5 – RELIABILITY AND RESILIENCY

CHAPTER HIGHLIGHTS

- Regional resource adequacy assessments highlight that there are resource adequacy risks through the mid-2020s. In conditions of increased demand and resource variability, higher summer temperatures reduce excess energy supply, in turn tightening supply from the market.
- PacifiCorp's wildfire mitigation plans, which outline a risk-based, balanced, and integrated approach, contain six critical focus areas of planning and execution for a reliable and resilient energy future: (1) Risk analysis and drivers, (2) Situational awareness, (3) Inspection and correction, (4) Vegetation management, (5) System hardening, and (6) Operational practices.
- The 2025 IRP preferred portfolio includes the Energy Gateway South (GWS) and Energy Gateway West segment D.1, which are currently operational. The preferred portfolio also includes future transmission upgrades that support the transition to renewable energy by providing access to low-cost, location-specific renewable resources, and additional transfer capability, which enables greater use of low-cost resource options and relieves stress on current assets.

Introduction

Serving reliably (i.e., keeping the lights on for customers), as well as planning for a resilient system (i.e., operating through and recovering from a major disruption) is a primary focus for PacifiCorp. With the increasing retirement of thermal baseload resources, the incorporation of increasing numbers of intermittent renewable resources, and the impacts of climate change, planning for a reliable and resilient energy future is more crucial, and more complex, than ever. PacifiCorp continues to build on a strong history of serving its customers safely, reliably, and affordably.

The focus on reliability and resiliency spans across several areas of the company: PacifiCorp's resource planning and energy supply teams work closely with regional partners and ensure that there is sufficient supply to serve customers, while transmission and distribution teams work to mitigate the destructive impact of wildfire risk throughout the west to ensure that PacifiCorp can deliver power safely to customers now and in the future.

Supply-Based Reliability

Regional Resource Adequacy

As part of its 2025 IRP, PacifiCorp has conducted a review and evaluation of western resource adequacy studies and information.

In December 2024 the Western Electricity Coordinating Council (WECC) published the Western Assessment of Resource Adequacy (WARA), which serves as an interconnection-wide assessment of resource adequacy as discussed below. PacifiCorp also reviewed the 2020 North American Electric Reliability Council (NERC) Long-Term Reliability Assessment and the status of resource adequacy assessments prepared for the Pacific Northwest by the Pacific Northwest Resource Adequacy Forum.

WECC Western Assessment of Resource Adequacy Report

The WECC WARA was published in December 2024 and was developed based on data collected from balancing authorities describing their own demand and supply projections over the next 10 years.[1] The analysis is probabilistic and represents an hourly assessment of resource adequacy over the study period. A key driver of the results is the forecasted growth in load across the west, which is projected to increase by over 20.4% in the next ten years (on an energy basis), more than double the 9.6% growth forecast from the 2022 WARA. PacifiCorp's loads are located in the NW-Northwest and NW-Central regions evaluated as part of the WARA. Peak demand in the NW-Northwest region is forecasted to grow by 13.5% in the next ten years, while the NW-Central region is forecasted to grow by 8.5% over the same time. While significant, these are both lower than the growth of the Western Interconnection as whole, where growth is projected at 17.2%, driven by increases in California and the Desert Southwest.

Resource plans have identified a vast quantity of resources to meet this demand, 172 GW of new generation resources, which is more than double the generation capacity added in the last ten years. Plans include 68 GW of solar capacity additions in the next ten years, while will nearly triple the 35 GW in operation in 2023, plus 40 GW of wind capacity additions in the next ten years, relative to 37 GW in operation in 2023. Similarly, battery storage is projected to grow by 37 GW. The WARA highlights concerns that planned resources will not be brought online in a timely manner and includes four scenarios evaluating various levels of resource build out.

In the "All Additions" scenario, which includes all planned resources, the WARA identifies risks in the NW-Northwest region, primarily in the winter, and primarily in 2029 and later. Risks increase and appear in other regions if lower levels of planned resources are achieved, as summarized in Table 5.1.

Table 5.1 – WARA Demand-at-Risk Summary[2]

	Month											
	55% Resource Additions Scenario											
Region	1	2	3	4	5	6	7	8	9	10	11	12
California	-	-	-	-	-	-	-	-	-	-	-	-
Desert Southwest	-	-	-	-	-	-	Medium	Medium	Low	-	-	-
NW-Northwest	High	High	Medium	Low	-	-	Low	Medium	Medium	High	High	High
NW-Northeast	-	Low	-	-	-	-	Low	Medium	-	-	-	-
NW-Central	-	-	-	-	-	Low	Medium	Medium	Medium	-	-	-
	Month											
	85% Resource Additions Scenario											
Region	1	2	3	4	5	6	7	8	9	10	11	12
California	-	-	-	-	-	-	-	-	-	-	-	-
Desert Southwest	-	-	-	-	-	-	-	-	-	-	-	-
NW-Northwest	Medium	Medium	-	-	-	-	-	Low	-	Medium	Low	Medium
NW-Northeast	-	Low	-	-	-	-	-	Low	-	-	-	-
NW-Central	-	-	-	-	-	Low	Low	Low	Medium	-	-	-

Risk reflects the count of hours in each month that exceed a one-day-in-ten-years threshold by 2034.

High >50 hours Medium 10-49 hours Low <10 hours

[1] WECC. Western Assessment of Resource Adequacy 2024. Available online: https://feature.wecc.org/wara/ (accessed 12/18/2024)

[2] WECC. WARA 2024 Demand-at-Risk Hours by Subregion. Available online at: https://www.wecc.org/wecc-document/17071 (Accessed 12/18/2024)

The NW-Northwest and NW-Central regions which include PacifiCorp's load both have hours at risk. In the NW-Northwest region, significant risk exists in both the summer and winter seasons. While PacifiCorp has significant transfer capability into the NW-Northwest and proportionately lower dependence on hydropower than the NW-Northwest region as a whole, regional capacity limitations would result in less margin for error. In the NW-Central region, risks are somewhat lower, and concentrated in the summer, but still indicate that incremental resources are necessary to serve growing loads. The results shown assume import capability between sub-regions – in the absence of imports, risks are high in the NW-Northwest and NW-Central regions even if all planned new resources are built.

The WARA characterizes four risks that impact planned resource additions: supply chain disruptions, interconnection queue, siting delays, and increased costs. Some of the impacts are reduced because of PacifiCorp's particular circumstances. PacifiCorp's relatively large portfolio and geographic footprint create a wider range of opportunities than are available to many other utilities, increasing the likelihood that some new projects will be able to proceed. This is bolstered by PacifiCorp's implementation of a cluster study interconnection process in 2020, which has enabled large numbers of interconnection requests to be processed more quickly than was possible in the past, increasing the likelihood that projects will be available in desired timeframes. After cost-effective projects are identified, PacifiCorp's relatively large demand allows it to contract with multiple developers for multiple sites, reducing the impact if any single developer or site falls through or is delayed. That said, substantial risks remain for any resource additions.

The WARA also characterizes risks associated with other factors: resource variability, transmission considerations, energy policy, and extreme weather. The limitations of wind, solar, and energy-limited resources like energy storage are different from those of baseload or dispatchable resources, and those limitations become more restrictive as the share of these resources increases. Given the expected tripling of solar capacity and doubling of wind capacity, variability is expected to increase significantly. The variability and operational requirements of that future resource mix is not fully characterized and could be impacted further by extreme weather events. The other risk factors cover a range of planning and policy considerations, and the process through which resource and transmission build outs are implemented. Utility planning and procurement takes time, and the build out of resources and transmission is reliant upon a range of state and federal processes and requirements.

NERC Long-Term Reliability Assessment (LTRA)

Resources

As part of the regional reliability assessment to support the 2025 IRP, PacifiCorp reviewed and incorporated learnings from the NERC LTRA, published in December 2024.[3] The NERC LTRA organizes prospective resources into three broad capacity supply categories in its 10-year WECC region reliability assessment:

- Tier 1: resources under construction, or with signed contracts.
- Tier 2: resources with completed interconnection studies.
- Tier 3: resources in an interconnection queue that do not meet the Tier 2 requirement.

Planning Reserve Margin

The LTRA defines "planning reserve margin" as the difference between resources and demand, divided by demand, expressed as a percentile.

Comparing the *anticipated* resource-based reserve margin to the reference planning margin yields one of three risk determinations:

- High Risk: shortfalls may occur at normal peak conditions.
- Elevated Risk: shortfalls may occur in extreme conditions.
- Normal Risk: low likelihood of electricity supply shortfall.

WECC Subregions

Table 5.2 presents the WECC subregions used for the NERC LTRA. In the data that follows, the two subregions in Canada are not considered.

Table 5.2 – WECC Subregion Descriptions

Designation	Subregion	Country	Peak
NW	The rest of WECC, beyond the exceptions listed below	United States	Summer
SW	Primarily Arizona and New Mexico	United States	Summer
CA/MX	California / Mexico	United States	Summer
AB	Alberta	Canada	Winter
BC	British Columbia	Canada	Winter

LTRA WECC Assessment

Table 5.3 presents the WECC LTRA assessments for the three WECC subregions that include the United States. Anticipated Reserve Margin is based on existing resources, firm transfers, and Tier 1 additions, less confirmed retirements. Prospective Reserve Margin adds existing resources without firm transmission, or with other potential limitations, likely transfers, and Tier 2 capacity additions, less unconfirmed retirements. Values that fall below the reference margin level (i.e. planning target) are highlighted.

[3] NERC. 2024 Long-Term Reliability Assessment. December 2024. Available online at: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf (accessed 12/18/2024)

Table 5.3 – NERC LTRA for Selected WECC Subregions

WECC-NW

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Anticipated Reserve Margin (%)	38.7%	37.7%	34.1%	29.3%	23.3%	17.0%	10.8%	8.9%	6.7%	4.6%
Prospective Reserve Margin (%)	39.9%	40.6%	37.8%	34.2%	30.0%	25.7%	20.4%	18.4%	15.7%	13.9%
Reference Margin Level (%)	*16.3%*	*15.8%*	*15.9%*	*15.4%*	*14.7%*	*14.5%*	*14.3%*	*14.2%*	*14.4%*	*13.8%*

WECC-SW

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Anticipated Reserve Margin (%)	36.9%	35.6%	31.8%	24.2%	17.4%	11.3%	7.7%	0.2%	-4.7%	-8.7%
Prospective Reserve Margin (%)	38.6%	40.1%	38.2%	31.1%	26.7%	20.4%	16.8%	9.2%	4.9%	0.0%
Reference Margin Level (%)	*11.0%*	*10.8%*	*12.0%*	*11.7%*	*10.2%*	*10.1%*	*9.9%*	*9.7%*	*10.8%*	*9.4%*

WECC-CA/MX

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Anticipated Reserve Margin (%)	45.8%	45.2%	38.4%	43.1%	28.8%	29.6%	23.3%	25.0%	15.2%	11.1%
Prospective Reserve Margin (%)	51.8%	55.1%	48.2%	62.5%	45.6%	57.9%	51.0%	59.0%	50.2%	47.3%
Reference Margin Level (%)	*17.4%*	*17.4%*	*16.4%*	*17.4%*	*16.6%*	*16.4%*	*16.1%*	*16.3%*	*14.9%*	*15.3%*

As shown, the WECC-NW subregion that includes PacifiCorp's load meets the reference margin with anticipated resources through 2030, and with prospective resources through the ten-year horizon. The WECC-SW subregion also meets the reference margin with anticipated resources through 2030 but only has sufficient prospective resources through 2031. The WECC-CA/MX region meets the reference margin with anticipated resources through 2033, and with prospective resources through the ten-year horizon. While this presents a relatively favorable view of supply and demand, the LTRA definition of Tier 1 resources includes everything with an interconnection agreement and/or power purchase agreement. Not all such resources will ultimately be brought online in a timely manner. The factors identified the WECC WARA (supply chain disruptions, interconnection queue, siting delays, and increased costs) can all derail projects that are otherwise feasible.

Pacific Northwest Power Supply Adequacy Assessment

The Northwest Power and Conservation Council released its 2029 Adequacy Assessment in August 2024.[4] Starting in 2011, an annual loss-of-load-probability of up to five percent was deemed adequate. Starting with the 2023 assessment a multi-metric framework of shortfall frequency, duration, and magnitude was used. These metrics include:

- **Loss of load events (LOLEV):** limits the expected frequency of shortfall events to protect against frequent use of emergency measures.
- **Duration Value at Risk**: limits shortfall duration to protect against tail-end (extreme) duration use of emergency measures.
- **Peak Value at Risk**: limits maximum hour capacity shortfall to protect against tail-end (extreme) magnitude of emergency measures.
- **Energy Value at Risk**: limits total annual energy shortfall to protect against tail-end (extreme) annual aggregate use of emergency measures.

An adequate system must meet all these metrics. The 2029 Adequacy Assessment is based on the 2021 Northwest Power Plan, discussed below, with updates for expected changes through 2029, including load growth, resource development, and transmission. Based on updated results for adequacy in year 2029, the 2029 Adequacy Assessment concludes that power supply would be

[4] Northwest Power and Conservation Council. Pacific Northwest Power Supply Adequacy Assessment for 2029. August 2024. Available online at: https://www.nwcouncil.org/fs/18853/2024-4.pdf (accessed 12/18/2024)

adequate under reference conditions. This conclusion is in part based on coal plants changing to natural gas, rather than retiring (including Jim Bridger 1 and 2, which were converted in 2024). The 2029 Adequacy Assessment identifies two scenarios that could lead to reliability shortfalls. First, if energy efficiency savings only meet the low end of the targeted quantity, shortfall risks increase in the winter. Second, higher data center loads in the absence of commensurate resource supply could lead to reliability shortfalls in both the winter and the summer. An additional potential risk is related to the Boardman-to-Hemingway project which the 2029 Adequacy Assessment assumes is operational by 2029, increasing transfer capability between Idaho and the Pacific Northwest, as this upgrade is not part of PacifiCorp's 2025 IRP preferred portfolio. The metric results from the 2029 Adequacy Assessment are provided in Table 5.4, with shortfalls highlighted in orange.

Table 5.4 – Northwest Power and Conservation Council 2029 Adequacy Assessment

Type	Metric	Threshold	Reference	Low End EE	Higher Data Center
Frequency	Winter LOLEV	0.1	0.022	0.35	1.294
Frequency	Summer LOLEV	0.1	0.017	0.033	0.3
Duration	Duration VaR 97.5	8 hours	0	1.5	20.6
Magnitude	Peak VaR 97.5	1200 MW	0	1,567	3,076
Magnitude	Energy VaR 97.5	9600 MWh	0	4,196	196,324

Western Resource Adequacy Program (WRAP)

The WRAP is a regional reliability planning and compliance program, intended to help facilitate region-wide resource adequacy, and initiated on behalf of the utilities that are part of the Western Power Pool (formerly the Northwest Power Pool). WRAP allows for coordination and visibility of resource needs and supply among the participants, taking advantage of the diversity and sharing from pooling resources.

WRAP begins with regional analysis, as the program sets regional reliability metrics for upcoming seasons, including planning reserve margins that are applied to loads and qualifying capacity contributions that apply to resources. With those values in hand, utilities must secure resources and, seven months prior to the start of a winter or summer season, must submit a forward showing demonstrating they have resources and transmission to cover their load and planning reserve margin requirements. Time is provided to cover shortfalls before the season begins. Within the season, an operational component allows those participants with a day-ahead resource shortfall to call upon the program and receive incremental resources from participants who have a surplus.

WRAP is based on two seasons: summer (June through September) and winter (November through March). Planning reserve margins vary by month, and by region, as WRAP covers two regions: the Pacific Northwest (primarily Oregon and Washington and British Columbia, with parts of northern Idaho and Montana) and the Desert Southwest, including the remainder of Idaho, Utah, Wyoming, Colorado, Nevada, and Arizona. Similarly, monthly qualifying capacity contributions are calculated for each resource, and capture technology type, regional variations, and resource-specific performance. For example, wind and solar contributions incorporate a resource's output

during capacity critical hours (the highest load hours after netting out wind, solar, and run of river hydro generation).

As of September 2024, the Western Power Pool Board of Directors has approved updates to the WRAP tariff along with seven business practice manuals detailing of the program will operate. WRAP is currently operational with non-binding requirements and has plans in place to enable fully binding operations in Summer 2027 for participants that provide notice of their intent by January 2026. All participants will be binding for Winter 2027-2028 (i.e. starting November 2027). If a WRAP Participant chooses to exit the program, a two-year exit period applies. Current WRAP Participants have until October 31st, 2025, to exit the program without being subject to a financially binding season.

PacifiCorp is currently participating in WRAP and is working with the Western Power Pool to address outstanding issues, including the interaction between WRAP and the CAISO's Enhanced Day-Ahead Market (EDAM) and complexity from PacifiCorp's footprint spanning both WRAP regions. While issues remain, PacifiCorp's 2025 IRP includes modeling to capture WRAP compliance requirements starting in 2028 and continuing through the study horizon. While proxy resource selections within the 2025 IRP can only begin on January 1st of each year, actual resource procurement could be targeted to the November 2027 start date to the extent necessary, or short-term products could be used to address unmet requirements, if any.

Reliable Service through Unpredictable Weather and Challenging Market Liquidity

PacifiCorp, other utilities, and power marketers who own and operate generation engage in market purchases and sales of electricity on an ongoing basis to balance the system and maximize the economic efficiency of power system operations. In addition to reflecting spot market purchase activity and existing long-term purchase contracts in the IRP portfolio analysis, PacifiCorp previous IRP modeling has included front office transactions (FOT). FOTs are proxy resources, assumed to be firm, that represent procurement activity made on an on-going forward basis to help PacifiCorp cover short positions. However, market transactions that are not based on a specified source do not provide qualifying capacity for WRAP compliance. While other short-term products exist, such as slices of hydropower projects on the Mid-Columbia or tolling agreements for merchant-owned natural gas plants, there are relatively few such opportunities and there may be significant competition for such products given rising demand and stricter resource adequacy requirements under WRAP. With that in mind, for the 2025 IRP, PacifiCorp is not including short-term market products as options for WRAP compliance.

WRAP compliance does not guarantee reliability, in particular a monthly qualifying capacity contribution value does not ensure resources will be available to meet hourly requirements such as the hourly balancing test in the EDAM. At the same time, PacifiCorp recognizes that increasing coordination of spot market transactions through EIM, EDAM, and WRAP is likely to provide significant economic benefits. To balance the limitations of market transactions for capacity and reliability requirements and the benefits of market transactions for regional dispatch, the 2025 IRP does not allow market purchases in certain key periods, but otherwise allows market purchases up to transmission limits. During the summer WRAP season (June through September), market purchases are not allowed from 4:00 p.m. to 12:00 a.m. on PacifiCorp's top five load days in each month. Similarly, in the winter WRAP season (November through March), market purchases are

not allowed from 4:00 a.m. to 8:00 a.m. as well as 4:00 p.m. to 12:00 a.m., again on PacifiCorp's top five load days in each month. For the 2025 IRP, PacifiCorp is also differentiating market prices within each month, to reflect historical patterns on the days used to derive the chaotic normal load forecast and reflecting the same weather conditions used to develop wind and solar generation profiles. In general, market prices are higher when load is high and wind and solar output is relatively low, though market prices reflect region-wide conditions of PacifiCorp's supply and demand is only a part. Market prices in EIM and EDAM will reflect the balance of supply-and-demand, and surplus supply from PacifiCorp is likely to result in lower market clearing prices. While this effect is not captured in PacifiCorp's hourly market price forecast, market sales for the 2025 IRP have been capped at historical average levels, since large surpluses would impact pricing.

Aligned with review of the regional studies discussed above, and the historical market purchases and transactions, the company will continue to refine its assessments of market depth and liquidity for transactions to quantify the risk associated with the level of market reliance. Additional description is provided in Volume I, Chapter 7 (Resource Options); also, see the sensitivities discussion in Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection Results).

Planning for Load Changes as a Result of Climate Change

Recent weather-based reliability events throughout the United States have underscored the need for utilities to consider the potential for increasingly extreme weather and the underlying reliability challenges that may be caused as part of its planning process. PacifiCorp has accounted for climate change within the 2025 IRP to assess the ways in which climate change may impact planning assumptions.

The Company's load forecast is based on historical actual weather adjusted for expectations and impacts from climate change. The historical weather is defined by the 20-year period of 2004 through 2023. The climate change weather uses the data from the historical period and adjusts the percentile of the data to achieve the expected target average annual temperature and calculate the HDD and CDD impacts and peak producing weather impacts within the energy forecast and peak forecast, respectively. These temperature changes lead to higher summer peaks and lower winter peaks, with increasing impacts across the study horizon. See Appendix A for additional detail regarding how climate change is incorporated into the load forecast.

Weather-Related Impacts to Variable Generation

New for the 2025 IRP, all wind and solar generation profiles are based on historical weather conditions on the same historical day underlying the load forecast. This captures the relationship between load, wind, and solar that happened in recent history. Each month of the Company's chaotic normal load forecast reflects the range of weather conditions experienced in the most typical month from 2013-2022, while stochastic analysis for the 2025 IRP will reflect the range of weather conditions experienced in every year from 2006-2023. The effect of extreme weather events associated with climate change is an evolving area of research that is growing in importance as renewable, intermittent resources dependent upon wind, solar, and hydrologic conditions comprise an increasing proportion of utility resource portfolios. For the 2025 IRP, PacifiCorp is not projecting specific climate impacts on wind and solar generation but notes that recent history

may be more representative of future conditions than earlier conditions. As a result, reliability and system cost risks identified using inputs derived from recent historical years may be of greater concern as an indicator of future risk.

Wildfire Impacts

Increased wildfire frequency associated with climate change is expected to have a range of impacts to intermittent generation sources, including wind, solar, and hydro resources.

Wind generation sites in PacifiCorp's system are most likely to be subjected to fast moving range fires. Impacts at wind generation sites from range fires are likely to be limited and short in duration, as turbines and collector substations are surrounded by gravel surfaces that are fire resistant. Sensitive turbine equipment is located far above the ground away from damaging heat sources. Impacts to transmission lines and aboveground collector lines from range fires at wind generation sites is also anticipated to be minor due to the limited fuels available to cause ignition to wooden poles. Outage durations are likely to be short when operations staff is required to evacuate a site in advance of a fire and to curtail generation as a precautionary measure.

Climate change also poses fire risks at solar generation sites, which are also likely to manifest as range fires given solar projects are typically sited away from substantial tree stands that could block solar panels. Impacts could be significant depending on the amount of vegetation at a site, as generating equipment is close to the ground close to potential fuel sources. If a range fire creates sufficient heat to impact equipment, resumption of generation will be dependent on the ability to obtain and install necessary replacement equipment.

Fire impacts at hydro generation sites will be driven primarily by impacts to transmission lines. Hydro generation sites are typically in heavily forested terrain and serviced by only one or two transmission lines. An intense forest fire can damage miles of transmission lines that can take weeks to months to restore to service. If a fire threatens a hydro generation site, the site will be proactively evacuated with generation units typically taken offline and the facility put into spill to avoid potential instream flow impacts that could occur with an unplanned unit shutdown resulting from impacts to local transmission lines. Generation units would be restarted as soon as possible when conditions permit safe re-entry to provide generation locally until transmission service, if interrupted, is restored. Fire damage to dams, water conveyance structures, and generating plants is expected to be minimal. Damage to local distribution lines and communication infrastructure upon which hydro generation sources rely is also possible, which could impact generation restoration timelines.

PacifiCorp outlines its wildfire mitigation strategies later in this document.

Extreme Weather Impacts

Climate change also has the potential to result in increased frequency and magnitude of extreme weather events. Such changes can result in more frequent and intense precipitation events and flooding, which could impact hydropower generation and change historic operating practices to maintain flood control capabilities at projects where flood control benefits are part of project operations. Like wildfire events, increased flooding has the potential to impact access to remote hydro facilities. Increased precipitation and reduced snow water equivalent have the potential to

modify runoff patterns impacting hydro generation but is not expected to impact dam safety at PacifiCorp hydro facilities, which are subject to FERC dam safety requirements that ensure they are able to safely pass probable maximum flood events. Increases in extreme weather that results in more frequent flood events has the potential to increase debris loading in river systems and reservoirs, potentially increasing generation downtime to remove debris that may reduce inflows to hydro units or reduce flows through fish screens.

Changes to wind patterns and wind speeds, and changes in extreme high and low air temperatures have the potential to impact wind and solar generation. Extreme high temperatures can raise ground temperatures, which has the potential to impact collector system capacities at wind and solar projects and reduce collector system carrying capacity, limiting output, similar to high temperature impacts to high voltage transmission lines. However, these impacts are not anticipated to be significant on wind energy resources given peak output is typically observed outside of summer months. Increasing air temperatures result in lower air densities, which could negatively impact wind energy output even if wind speeds are unchanged. Lower wind speeds in the summer relative to historic experience because of extreme high temperatures is also possible. Wind turbines in PacifiCorp's fleet generally are protected from extreme low temperatures given the conditions in which they currently operate, and low temperature protection features are installed in PacifiCorp turbines where weather conditions warrant their inclusion.

There is limited research on site-specific impacts from extreme weather events and thus how to plan to improve the resiliency of intermittent generation resources. Resiliency will be enhanced as planning to ensure site access occurs in response to observed changes in extreme weather events and as more research is available to locally forecast impacts of climate change and extreme weather so those impacts can be factored into the resource planning process.

Impacts on Wind and Solar Energy

The impact on renewable energy generation due to extreme weather events and climate change is an evolving topic. For conclusive trends of climate change impact, data collection specific to geographic locations is critical. Climate impacts both the demand and supply side of energy. Due to daily or seasonal changes the demand for energy patterns is changing. On the supply side due to increasing temperatures and variability in climate parameters it impacts estimated energy outputs of projects as well as operational costs. However, there are limited studies in the North American region that quantitatively document the impact of a climate parameter on the future of wind and solar energy.[5] Some broad impacts anticipated from climate change are noted below:[6]

Wind Energy

- Changes to wind speed: could impact energy assessments.
- Changes in temperature: with increased temperatures the air density could reduce energy outputs.
- Changes in seasonal or daily wind: could disrupt correlation between wind energy and grid load demand.

[5] Climate change impacts on the energy system: a review of trends and gaps. Cronin, J., Anandarajah, G. & Dessens, O. Climatic Change volume 151, August 2018.

[6] Climate change impacts on renewable energy generation. A review of quantitative projections. Kepa Solaun, Emilio Cerdá. Renewable and Sustainable Energy Reviews

- Rising sea levels: could damage offshore wind farm infrastructure.

Solar Energy

- Changes in mean temperatures: increased global temperatures could reduce cell efficiency.
- Changes in solar irradiation, dirt, snow, precipitation: increase in these variables could reduce energy output.

Integration of energy storage with wind and solar projects is a way to help make use of generated energy more efficiently.

Wildfire Risk Mitigation

PacifiCorp's Wildfire Mitigation Plans (WMPs) are designed to meet regulatory requirements while delivering safe and reliable power. These plans focus on enhancing situational awareness, implementing robust operational practices, and hardening the power system to mitigate wildfire risks while balancing customer and community impacts.[7]

PacifiCorp Wildfire Mitigation Plan Regulatory Compliance

PacifiCorp meets regulatory requirements through the submittal of Wildfire Mitigation Plans (WMPs) with the specific regulatory alignments for each state stated below:

1. **California**: The WMP complies with California Senate Bill 901 and the California Public Utilities Commission (CPUC) provisions under Section 8386.
2. **Idaho**: The WMP was submitted in accordance with Idaho Public Utilities Commission Order No. 36045.
3. **Utah**: The WMP adheres to Utah Administrative Code R746-315-2, effective June 1, 2023, and complies with Subsection 54-24-201.
4. **Oregon**: The WMP meets the requirements set forth in Oregon Administrative Rule 860-300-0040.
5. **Washington**: The WMP was submitted on October 31, 2024, and compliance with statutory requirements was confirmed by the Washington Utilities and Transportation Commission as complying with the Revised Code of Washington (RCW) 80.28.440.

Although Wyoming does not have regulatory requirements for a wildfire mitigation plan, PacifiCorp has proactively filed one in conjunction with the general rate case.

Core Principles

All WMPs are publicly accessible via the PacifiCorp Wildfire Mitigation Plan website (linked here). These plans detail the investments and strategies for constructing, maintaining, and operating electrical lines and equipment for wildfire mitigation projects and programs. While there

[7] Wildfire mitigation and impacts were discussed in the 2025 IRP public input meeting series and stakeholder feedback. See Appendix M, stakeholder feedback form #18 (Wyoming Office of Consumer Advocate).

are state-specific requirements, the core strategy across all six states remains consistent, guided by the following principles:

- **Situational Awareness and Operational Readiness**: Implementing systems that enhance situational awareness, and operational readiness is crucial for mitigating fire risks and their impacts.
- **Operational Practices**: Minimizing the impact of fault events through rapid isolation using advanced equipment and trained personnel.
- **System Hardening**: Reducing the frequency of ignition events by engineering more resilient systems that experience fewer faults.

Balancing Mitigation and Community Impact

PacifiCorp is committed to balancing wildfire risk mitigation with the needs of customers and communities. Adjustments to power system operations, such as modifying protective device settings and testing protocols, are carefully considered to reduce wildfire risks. These measures are applied selectively to avoid unnecessary disruptions to the power supply.

The wildfire mitigation program approach includes deploying advanced technologies like fault indicators and assessing outages to inform short-term mitigation projects. These efforts are designed to enhance safety while maintaining reliable service.

PacifiCorp's Wildfire Mitigation Plans (WMPs) reflect the Company's dedication to balancing costs, benefits, operational impacts, and risk mitigation with the goal to provide safe, reliable, and affordable electric service, prioritizing the well-being of customers and communities.

Transmission-Based Reliability

PacifiCorp is required to meet mandatory FERC, NERC, and WECC reliability standards and planning requirements. The operation of PacifiCorp's transmission system also responds to requests issued by California Independent System Operator (CAISO) RC West as the NERC Reliability Coordinator for PacifiCorp. The company conducts annual system assessments to confirm minimum levels of system performance during a wide range of operating conditions, from serving loads with all system elements in service to extreme conditions where portions of the system are out of service. Factored into these assessments are load growth forecasts, operating history, seasonal performance, resource additions or removals, new transmission asset additions, and the largest transmission and generation contingencies. Based on these analyses, PacifiCorp identifies any potential system deficiencies and determines the infrastructure improvements needed to reliably meet customer loads. NERC planning standards define reliability of the interconnected bulk electric system in terms of adequacy and security. Adequacy is the electric system's ability to meet aggregate electrical demand for customers at all times. Security is the electric system's ability to withstand sudden disturbances or unanticipated loss of system elements. Increasing transmission capacity often requires redundant facilities to meet NERC reliability criteria.

With the increasing number of variable resources added to the grid throughout the west, PacifiCorp's ability to meet federal reliability directives depends increasingly on an interconnected transmission system across the western states and on the ability to move electricity throughout the six states served by the company. PacifiCorp's planning process ensures that the company is developing a portfolio that balances sufficient supply to serve all PacifiCorp customers with sufficient resources and transmission to ensure that electricity can be moved from generation sources to the communities served.

PacifiCorp's interconnection to other balancing authority areas and participation in the Energy Imbalance Market provide access to markets and promote affordable and reliable service to PacifiCorp's customers. Further, PacifiCorp's transmission capacity provides benefits to customers by increasing reliability and allowing additional generation to interconnect to serve customer load, as well as allowing PacifiCorp flexibility in designating generating resources for reserve capacity to comply with mandatory reliability standards.

Federal Reliability Standards

The Energy Policy Act of 2005 included expanded reliability-related elements of the federal regulatory structure and directed the FERC to institute mandatory reliability standards that all users of the bulk electric system (BES) must follow.

FERC delegated the authority to NERC to develop reliability standards to ensure the safe and reliable operation of the BES in the United States under a variety of operating conditions. These standards are a federal requirement and are subject to oversight and enforcement by the WECC, NERC, and FERC. PacifiCorp is subject to compliance audits every three years and may be required to prove compliance during other reliability initiatives or investigations.

The transmission planning standards (TPL Standards), found within the NERC transmission reliability standards, specify transmission system planning performance requirements to develop a BES that will operate reliably over a broad spectrum of system conditions. They also require study of a wide range of probable contingencies in short-term (1-2 years), medium term (5 years) and long-term (10-20 years) scenarios to ensure system reliability. Together with regional planning criteria, such as those established by the NERC/WECC, and utility-specific planning criteria, the TPL Standards define the minimum transmission system requirements to safely and reliably serve customers.

In addition to the TPL Standards, PacifiCorp is also required to comply with FERC Order 1000 as detailed in Attachment K of the Open Access Transmission Tariff (OATT) which requires PacifiCorp to participate in regional transmission planning processes that satisfy the transmission planning principles of FERC Order 890 and produce a regional transmission plan. To meet this requirement PacifiCorp is a member of the NorthernGrid regional planning association. The development of the regional transmission plan ensures the regional reliability is maintained and/or enhanced with the addition of new planned generation and transmission projects while reliably serving PacifiCorp customers. In 2024, FERC issued Order 1920 which will further expand regional planning processes, including a requirement for a long-term (20 year) regional plan. PacifiCorp is working with NorthernGrid members to draft tariff revisions to outline the expanded process in preparation for the FERC required compliance filing in August 2025.

Power Flow Analyses and Planning for Generator Retirements

PacifiCorp transmission planning has performed various coal unit retirement assessments analyzing potential impacts to the transmission system. These studies are performed outside of the IRP process under PacifiCorp's OATT processes which includes either 1) a customer request to perform a consulting study; or 2) a customer request to un-designate a network resource which then triggers a system impact and facilities study if the study determines that mitigations are required due to retirement.

Past studies have found that several factors are critical in determining transmission system impacts and necessary mitigation, if any. These factors include: 1) location of the unit(s) to be retired, 2) the number of units being retired, 3) the size of the units being retired, 4) year of retirement, and 5) location, size, and type of replacement resources, if any. Based on the location, number of units, and size of the retired unit/s, studies can identify if the retirement results in either thermal or voltage issues on the transmission system. A retirement of a coal unit may result in voltage issues due to lack of reactive support that was previously provided by the retired unit/s. A retirement may also result in thermal overload of the transmission system due to changes in the flows post unit retirement. As such, until official notification to PacifiCorp transmission of coal unit designation/retirement is received, all such coal retirement analysis is considered preliminary.

CHAPTER 6 – LOAD AND RESOURCE BALANCE

CHAPTER HIGHLIGHTS

- New for the 2025 IRP, PacifiCorp is calculating its capacity position based on Western Resource Adequacy Program (WRAP) compliance requirements, with binding operations under the program expected to begin by 2028. WRAP participants with projected resource shortfalls on a day-ahead basis will be able to purchase from WRAP participants with excess supply.
- Every resource has a qualifying capacity contribution (QCC) for each month of the summer (June-September) and winter (November-March) seasons. These values are calculated by WRAP based on resource-specific historical performance and are based on the loads and resource mix of the regional participants. These values are updated by WRAP ahead of each compliance season.
- Seven months prior to the start of each season, WRAP participants must make a forward showing, demonstrating that the QCC for their resources is sufficient to meet their peak load plus a monthly planning reserve margin determined by WRAP.
- While WRAP is projected to enhance reliability by providing priority access to supply from other participants, the monthly QCC values do not ensure a utility will be reliable or have sufficient resources to meet its requirements from hour to hour, so hourly analysis of the load and resource balance is also necessary.
- On both a capacity and energy basis, PacifiCorp calculates load and resource balances from existing resources, forecasted loads and sales, and reserve requirements.
- The company's load obligation is calculated based on projected load less distributed generation, energy efficiency savings, and demand response, including interruptible load.
- A distributed generation study prepared by DNV produced estimates on distributed generation penetration levels specific to PacifiCorp's six-state territory. The study provided expected penetration levels by resource type, along with high and low penetration sensitivities. PacifiCorp's 2025 IRP load and resource balance reflects base case distributed generation penetration levels as a reduction in load.
- Relative to WRAP compliance requirements, PacifiCorp's system is capacity deficient (before adding proxy resources other than energy efficiency, and without considering short-term capacity procurement, i.e. market purchases) in the summer beginning in 2026, and the winter peaks throughout the planning horizon.
- The uncertainty in the company's load and resource balance is increasing as PacifiCorp's resource portfolio and customer demand evolve over time. PacifiCorp's 2025 IRP reflects renewable resource generation profiles based on the same patterns of historical weather conditions used to develop its load forecasts, both on a normalized basis and for stochastic analysis. While adjustments to account for climate change are included in the base forecast, customer demand may be further influenced by climate change directly as well as indirectly through electrification, with uncertain impacts on future demand. These resources and load relationships ultimately drive the frequency and characteristics of the relatively extreme conditions that are most likely to trigger reliability shortfalls.

Introduction

This chapter presents PacifiCorp's assessment of its load and resource balance. PacifiCorp's long-term load forecasts (both energy and coincident peak load) for each state and the system are summarized in Appendix A (Load Forecast). The summary-level system coincident peak is presented first, followed by a profile of PacifiCorp's existing resources. Finally, load and resource balances for capacity are presented. These balances are composed of a year-by-year comparison of projected loads against the existing resource base, assumed coal unit retirements and incremental new energy efficiency savings from the preferred portfolio, before adding new generating resources.

System Coincident Peak Load Forecast

System Coincident Peak Load Forecast

The system coincident peak load is the annual maximum hourly load on the system. The 2025 IRP relies on PacifiCorp's May 2024 load forecast. Table 6.1 shows the annual summer coincident peak load stated in megawatts (MW) as reported in the capacity load and resource balance before any load reductions from energy efficiency. The system summer peak load grows at a compound annual growth rate (CAGR) of 1.67 percent over the period 2025 through 2044.

Table 6.1 – Forecasted System Summer Coincident Peak Load in Megawatts, Before Energy Efficiency (MW)

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
System	11,318	11,270	11,425	11,553	11,690	11,844	12,104	12,193	12,363	12,575
	2035	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**
System	12,819	13,134	13,404	13,693	13,978	14,279	14,581	15,008	15,237	15,518

Existing Resources

Thermal Plants

Table 6.2 lists PacifiCorp's existing coal-fueled plants and Table 6.3 lists existing natural-gas-fueled plants. The "End of Coal-fired Operation" reflects the year a resource must retire or converts to natural gas (if option is available) as reflected in modeling inputs.

Table 6.2 – Coal-Fired Plants

Plant	PacifiCorp Percentage Share (%)	State	Nameplate Capacity (MW)	End of Coal-fired Operation
Colstrip 3	10	Montana	74	2025 (Transfer capacity to unit 4)
Colstrip 4	10*	Montana	74	2029 (PacifiCorp exit)
Craig 1	19	Colorado	82	2025 (Assumed end of life)
Craig 2	19	Colorado	79	2028 (Assumed end of life)
Dave Johnston 1	100	Wyoming	99	2028 (Gas conversion option)
Dave Johnston 2	100	Wyoming	106	2028 (Gas conversion option)
Dave Johnston 3	100	Wyoming	220	2027 (Retire: Clean air compliance)
Dave Johnston 4	100	Wyoming	330	
Hayden 1	24	Colorado	44	2028 (Assumed end of life)
Hayden 2	13	Colorado	33	2027 (Assumed end of life)
Hunter 1	94	Utah	418	
Hunter 2	60	Utah	269	
Hunter 3	100	Utah	471	
Huntington 1	100	Utah	459	
Huntington 2	100	Utah	450	
Jim Bridger 3	67	Wyoming	349	
Jim Bridger 4	67	Wyoming	351	
Naughton 1	100	Wyoming	156	2025 (Gas conversion option)
Naughton 2	100	Wyoming	201	2025 (Gas conversion option)
Wyodak	80	Wyoming	268	
TOTAL – Coal			**4,533**	

*PacifiCorp's share of Colstrip 4 is projected to include its current ownership of Colstrip 3 starting in 2026.

Table 6.3 – Natural Gas-Fired Plants

Plant	PacifiCorp Percentage Share (%)	State	Nameplate Capacity (MW)
Chehalis	100	Washington	500
Currant Creek	100	Utah	540
Gadsby 1	100	Utah	64
Gadsby 2	100	Utah	69
Gadsby 3	100	Utah	105
Gadsby 4	100	Utah	40
Gadsby 5	100	Utah	40
Gadsby 6	100	Utah	40
Hermiston	100	Oregon	237
Jim Bridger 1	67	Wyoming	354
Jim Bridger 2	67	Wyoming	359
Lake Side	100	Utah	580
Lake Side 2	100	Utah	677
Naughton 3	100	Wyoming	247
TOTAL – Natural Gas			**3,852**

Renewable Resources

Wind

PacifiCorp either owns or purchases under contract 5,154 MW of wind resources. Table 6.4 shows existing (or under construction) wind facilities owned by PacifiCorp, while Table 6.5 shows existing wind power-purchase agreements (PPAs).

Table 6.4 – Owned Wind Resources

Utility-Owned Wind Projects	State	Capacity (MW)
Goodnoe Hills East	WA	94
Leaning Juniper	WA	101
Marengo I	WA	156
Marengo II	WA	78
Cedar Springs 2	WY	199
Dunlap 1	WY	111
Ekola Flats 1	WY	250
Foote Creek I	WY	41
Glenrock I	WY	99
Glenrock III	WY	39
High Plains	WY	99
McFadden Ridge 1	WY	29
Pryor Mountain	WY	240
Rolling Hills	WY	99
Seven Mile Hill	WY	99
Seven Mile Hill II	WY	20
TB Flats 1-2	WY	500
Foote Creek II-IV	WY	43
Rock Creek I	WY	190
Rock Creek II	WY	400
Rock River	WY	50
TOTAL – Owned Wind		**2,937**

Table 6.5 – Non-Owned Wind Resources

Power Purchase Agreements	State	PPA or QF	Capacity (MW)
Wolverine Creek	ID	PPA	65
Chopin-Schumann	WA	QF	8
Cedar Springs I	WY	PPA	199
Cedar Springs III	WY	PPA	133
Three Buttes Power	WY	PPA	99
Top of the World	WY	PPA	200
Meadow Creek Project Five Pine	ID	QF	40
Meadow Creek Project North Point	ID	QF	80
Latigo	UT	QF	60
Mountain Wind I	UT	QF	61
Mountain Wind II	UT	QF	80
Power County Park North	UT	QF	23
Power County Park South	UT	QF	23
Spanish Fork Park 2	UT	QF	19

Tooele 1 and 2	UT	QF	3
Big Top	WA	QF	2
Butter Creek Power	WA	QF	5
Chopin	WA	QF	10
Four Corners	WA	QF	8
Four Mile Canyon	WA	QF	10
Orchard 1	WA	QF	10
Orchard 2	WA	QF	10
Orchard 3	WA	QF	10
Orchard 4	WA	QF	10
Oregon Trail	WA	QF	10
Pacific Canyon	WA	QF	8
Sand Ranch	WA	QF	10
Three Mile Canyon	WA	QF	8
Wagon Trail	WA	QF	3
Ward Butte	WA	QF	7
BLM Rawlins	WY	QF	0.1
Pioneer Park I	WY	QF	80
Cedar Creek	ID	PPA	152
Anticline	WY	PPA	101
Boswell	WY	PPA	320
Cedar Springs IV	WY	PPA	350
TOTAL – Purchased Wind			**2217**

Solar

PacifiCorp has a total of 97 solar projects under contract representing 3,615 MW of nameplate capacity. Of these, two recently signed solar resources also include a total of 550 MW of battery storage. Table 6.6 list solar power purchase agreements, and through Table 6.7 through Table 6.9 list solar qualifying facilities for each relevant state.

Table 6.6 – Solar Power Purchase Agreements

Power Purchase Agreements			
Resource	**State**	**Solar Capacity (MW)**	**Storage Capacity (MW)**
Black Cap	OR	2	-
Millican	OR	60	-
Old Mill	OR	5	-
Oregon Solar Incentive Project	OR	9	-
Prineville	OR	40	-
Appaloosa Solar IA	UT	120	-
Appaloosa Solar IB	UT	80	-
Castle Solar (Retail 1)	UT	20	-
Castle Solar (Retail 2)	UT	20	-
Cove Mountain	UT	58	-
Cove Mountain II	UT	122	-
Elektron Solar 20Yr	UT	10	-
Elektron Solar 25Yr	UT	70	-
Faraday	UT	525	150
Graphite	UT	80	-
Green River	UT	400	400
Hornshadow Solar I	UT	100	-
Hornshadow Solar II	UT	200	-
Horseshoe	UT	75	-
Hunter	UT	100	-
Milford	UT	99	-
Pavant III	UT	20	-
Rocket	UT	80	-
Sigurd	UT	80	-
TOTAL – Power Purchase Agreements		**2375**	**550**

Table 6.7 – Solar Qualifying Facilities, Oregon

Oregon Qualifying Facilities		
Resource	**Solar Capacity (MW)**	**Storage Capacity (MW)**
7 Mile Solar	1	-
Adams	10	-
Antelope Creek Solar	2	-
Bear Creek	10	-
Black Cap II	8	-
Blackwell Creek Solar*	1	-
Bly	8	-
Buckaroo Solar 1*	3	-
Buckaroo Solar 2*	3	-
Canyonville Solar 1*	1	-
Canyonville Solar 2*	2	-
Chapman Creek Solar*	3	-
Cherry Creek Solar*	0.4	-
Chiloquin Solar	10	-
Elbe	10	-
Goodling Community Solar*	1	-
Green Solar*	3	-
Hay Creek Solar*	0.6	-
Klamath Falls Solar 1	0.8	-
Klamath Falls Solar 2	3	-
Linkville Solar*	3	-
Merrill	10	-
Norwest Energy 2 (Neff)	10	-
Norwest Energy 4 (Bonanza)	6	-
Norwest Energy 7 (Eagle Point)	10	-
Norwest Energy 9 Pendleton	6	-
OR Solar 2, LLC (Agate Bay)	10	-
OR Solar 3, LLC (Turkey Hill)	10	-
OR Solar 6, LLC (Lakeview)	10	-
OR Solar 8, LLC (Dairy)	10	-
Orchard Knob Solar	2	-
OSLH Collier	10	-
Pilot Rock Solar 1*	3	-
Pilot Rock Solar 2*	3	-
Pine Grove Solar	1	-
Round Lake Solar	1	-
Skysol	55	-
Solorize Rogue*	0.1	-
Sunset Ridge Solar	2	-
Tumbleweed	10	-
Tutuilla Solar*	2	-
Wallowa County*	0.4	-
Whisky Creek Solar*	0.2	-
Wocus Marsh Solar*	0.9	-
Wood River Solar*	0.4	-
Woodline Solar	8	-
TOTAL – Oregon Solar QF Resources	**264**	**0**

*New project added in 2025 IRP

Table 6.8 – Solar Qualifying Facilities, Utah

Utah Qualifying Facilities		
Resource	**Solar Capacity (MW)**	**Storage Capacity (MW)**
Beryl	3	-
Buckhorn	3	-
CedarValley	3	-
Enterprise	80	-
Escalante I	80	-
Escalante II	80	-
Escalante III	80	-
Ewauna	1	-
Ewauna II	3	-
Granite Mountain - East	80	-
Granite Mountain - West	50	-
GranitePeak	3	-
Greenville	2	-
Iron Springs	80	-
Laho	3	-
Milford 2	3	-
Milford Flat	3	-
Pavant	50	-
Pavant II	50	-
Quichapa I	3	-
Quichapa II	3	-
Quichapa III	3	-
Red Hill	80	-
South Milford	3	-
SunE1	3	-
SunE2	3	-
SunE3	3	-
Three Peaks	80	-
TOTAL – Utah Solar QF Resources	**838**	**0**

Table 6.9 – Solar Qualifying Facilities, Wyoming

Wyoming Qualifying Facilities		
Resource	**Solar Capacity (MW)**	**Storage Capacity (MW)**
Sage I	20	-
Sage II	20	-
Sage III	18	-
Sweetwater	80	-
TOTAL – Wyoming Solar QF Resources	**138**	**0**

Geothermal

PacifiCorp owns and operates the Blundell geothermal plant in Utah, which uses naturally created steam to generate electricity. The plant has a net generation capacity of 34 MW. Blundell is a fully renewable, zero-discharge facility. The bottoming cycle, which increased the output by 11 MW,

was completed at the end of 2007. The Oregon Institute of Technology has a new small qualifying facility (QF) using geothermal technologies to produce renewable power for the campus that is rated at 0.28 MW. PacifiCorp also has a power purchase agreement with the 20 MW Soda Lake geothermal project located in Nevada, which became operational in November 2019.

Biomass/Biogas

PacifiCorp has biomass/biogas agreements with 12 projects totaling approximately 80 MW of nameplate capacity.

Distributed Generation Resources

Table 6.10 provides a breakdown of distributed generation capacity and customer counts from data collected as of March 31, 2024. In addition to resources, PacifiCorp's customers also have over 60 MW of battery storage capacity. For forecasted growth in distributed generation and storage, please refer to Appendix L (Distributed Generation Study).

Table 6.10 – Distributed generation Customers and Capacity

Fuel	Solar	Wind	Gas[1]	Hydro	Mixed[2]
Nameplate (kW)	772,160	847	784	965	1,233
Capacity (percentage of total)	99.51%	0.11%	0.10%	0.12%	0.16%
Number of customers	86,449	192	3	21	63
Customer (percentage of total)	99.68%	0.22%	0.00%	0.02%	0.07%

[1] Gas includes: biofuel, waste gas, and fuel cells

[2] Mixed includes projects with multiple technologies, one project is solar and biogas, and the others are solar and wind

Energy Storage

In addition to the battery storage contracted with solar resources listed in Table 6.6 PacifiCorp has existing or committed battery storage projects totaling approximately 523 MW of nameplate capacity, as shown in Table 6.11.

Table 6.11 – Storage Resources

Power Purchase Agreements / Exchanges	State	Technology	Capacity (MW)
Dominguez Storage*	UT	Battery	200
Enterprise*	UT	Battery	80
Escalante*	UT	Battery	80
Granite Mountain*	UT	Battery	80
Iron Springs*	UT	Battery	80
Panguitch	UT	Battery	1
Oregon Institute of Technology (OIT)	OR	Battery	2
TOTAL – Purchased Battery			**523**

*New project added in 2025 IRP

Hydroelectric Generation

PacifiCorp owns or purchases over 1,200 MW of hydroelectric generation capacity. In addition to being non-emitting generation sources hydro resources provide various operational benefits that

can include flexible generation, spinning reserves, and voltage control. PacifiCorp-owned hydroelectric plants are in California, Idaho, Montana, Oregon, Washington, Wyoming, and Utah.

The amount of electricity available from hydroelectric plants is dependent upon several factors, including the water content of snowpack accumulations in the mountains upstream of its hydroelectric facilities and the amount of precipitation that falls in its watershed. Operational limitations of the hydroelectric facilities are affected by varying water levels, licensing requirements for fish and aquatic habitat, and flood control.

Table 6.12 – PacifiCorp Hydroelectric Generation Facilities

Plant	River System	State	Capacity (MW)
East - Owned			
Cutler	Bear	UT	29
Grace	Bear	UT	33
Oneida	Bear	UT	27.9
Soda	Bear	UT	14
Small East [1/]	Other	UT	20.5
West - Owned			
Bend	Other	OR	1
Big Fork	Other	MT	4.6
Swift 1 [2/]	Lewis	WA	263.6
Yale	Lewis	WA	163.6
Merwin	Lewis	WA	151
Clearwater 1	N. Umpqua	OR	17.9
Clearwater 2	N. Umpqua	OR	31
Fish Creek	N. Umpqua	OR	10.4
Lemolo 1	N. Umpqua	OR	32
Lemolo 2	N. Umpqua	OR	38.5
Slide Creek	N. Umpqua	OR	18
Soda Springs	N. Umpqua	OR	11.6
Toketee	N. Umpqua	OR	45
Eagle Point	Rogue	OR	2.8
Prospect 1	Rogue	OR	4.6
Prospect 2	Rogue	OR	36
Prospect 3	Rogue	OR	7.7
Prospect 4	Rogue	OR	0.9
Fall Creek	Other	OR	2
Wallowa Falls	Other	OR	1.1
		Total Owned	**968**
Qualifying Facilities (QF)			
QF	Various	CA	9.4
QF	Various	ID	22.7
QF	Various	OR	40
QF	Various	UT	2.2
QF	Various	WA	2.9
Mid-Columbia	Columbia	WA	170
		Total QF	**247**
Total Hydroelectric			**1215**

[1/] Includes Ashton, Paris, Pioneer, Weber, Stairs, Granite, Veyo, Sand Cove, Viva Naughton, and Gunlock.

[2/] Cowlitz County PUD owns Swift No. 2 and is operated in coordination with other Lewis River projects by PacifiCorp.

Demand-Side Management/Distributed Generation

For resource planning purposes, PacifiCorp classifies demand-side management (DSM) resources into four categories, or "classes." These resources are captured through programmatic efforts that promote efficient electricity use through various intervention strategies, aimed at changing energy use during peak periods (load control), timing (price response and load shifting), intensity (energy efficiency), or behaviors (education and information). The four categories include:

- **Demand Response—Resources from fully dispatchable or scheduled firm capacity product offerings/programs:** Demand response programs are those for which capacity savings occur because of active company control or advanced scheduling. Once customers agree to participate in these programs, the timing and persistence of the load reduction is involuntary on their part within the agreed upon limits and parameters of the program. Modeling includes program drop-out rate and event non-performance rate assumptions to account for program parameters. Program examples include residential and small commercial central air conditioner load control programs that are dispatchable, and irrigation load management and interruptible or curtailment programs (which may be dispatchable or scheduled firm, depending on the particular program design or event noticing requirements). Savings are typically only sustained for the duration of the event and there may also be return energy associated with the program. These are considered Class 1 DSM resources.

- **Energy Efficiency—Resources from non-dispatchable, firm energy and capacity product offerings/programs:** Energy efficiency programs are energy and related capacity savings which are achieved through facilitation of technological advancements in equipment, appliances, structures, or repeatable and predictable voluntary actions on a customer's part to manage the energy use at their business or home. These programs generally provide financial incentives or services to customers to improve the efficiency of existing or new residential or commercial buildings through: (1) the installation of more efficient equipment, such as lighting, motors, air conditioners, or appliances; (2) increasing building efficiency, such as improved insulation levels or windows; or (3) behavioral modifications, such as strategic energy management efforts at businesses. The savings are considered firm over the life of the improvement or customer action. These are considered Class 2 DSM resources.

- **Price Response and Load Shifting—Resources from price-responsive energy and capacity product offerings/programs:** Price response and load shifting programs seek to achieve short-duration (hour by hour) energy and capacity savings from actions taken by customers voluntarily, based on a financial incentive or signal. As a result of their voluntary nature, participation tends to be low and savings are less predictable, making these resources less suitable to incorporate into resource planning, at least until their size and customer behavior profile provide sufficient information needed to model and plan for a reliable and predictable impact. The impacts of these resources may not be explicitly considered in the resource planning process; however, they are captured naturally in long-term load growth patterns and forecasts. Program examples include time-of-use pricing plans, critical peak pricing plans, and inverted block tariff designs. Savings are typically only sustained for the duration of the incentive offering and, in many cases, loads tend to be shifted rather than being avoided. These are considered Class 3 DSM resources.

- **Education and Information—Non-incented behavioral-based savings achieved through broad energy education and communication efforts:** Education and information programs promote reductions in energy or capacity usage through broad-based energy education and communication efforts. The program objectives are to help customers better understand how to manage their energy usage through no-cost actions such as conservative thermostat settings and turning off appliances, equipment, and lights when not in use. These programs are also used to increase customer awareness of additional actions they might take to save energy and the service and financial tools available to assist them. These programs help foster an understanding and appreciation of why utilities seek customer participation in other programs. Like price response and load shifting resources, the impacts of these programs may not be explicitly considered in the resource planning process; however, they are captured naturally in long-term load growth patterns and forecasts. Program examples include company brochures with energy savings tips, customer newsletters focusing on energy efficiency, case studies of customer energy efficiency projects, and public education and awareness programs. These are considered Class 4 DSM resources.

PacifiCorp has been operating successful DSM programs since the late 1970s. Over time, PacifiCorp's DSM acquisition has grown in investment levels, state presence, breadth of DSM resources pursued and resource planning considerations. Work continues on the expansion of cost-effective program portfolios and savings opportunities in all states while at the same time adapting programs and measure baselines to reflect the impacts of advancing state and federal energy codes and standards. In Oregon, PacifiCorp continues to work closely with the Energy Trust of Oregon to help identify additional resource opportunities, improve delivery and communication coordination, ensure adequate funding, and provide company support in pursuit of DSM resource targets.

Table 6.13 summarizes PacifiCorp's existing DSM programs, their assumed impact, and how they are treated for purposes of incremental resource planning. Note that since incremental energy efficiency is determined as an outcome of resource portfolio modeling and is characterized as a new resource in the preferred portfolio, existing energy efficiency in Table 6.13 is shown as having zero MW.[1] Similarly, demand response resources available to the preferred portfolio, are characterized as incremental to Table 6.13. For a summary of current DSM program offerings in each state, refer to Appendix D (Demand-Side Management Resources).

[1] The historical effects of previous energy efficiency savings are captured in the load forecast before the modeling for new energy efficiency.

Table 6.13 – Existing DSM Resource Summary

Program	Description	Energy Savings or Capacity at Generator	Included as Existing Resources for 2025-2045 Period
Demand Response	Residential/small commercial air conditioner load control	135 MW summer[1/]	Yes.
	Irrigation load management	200 MW summer	Yes.
	Interruptible contracts	136 MW summer	Yes.
	Wattsmart® Batteries	32 MW summer	Yes.
	Wattsmart® Business	45 MW summer	Yes.
Energy Efficiency	PacifiCorp and Energy Trust of Oregon programs	0 MW	No. Energy efficiency programs are modeled as resource options in the portfolio development process and included in the preferred portfolio.
Price Response and Load Shifting	Time-based pricing	Energy and capacity impacts are not available/measured.	No. Historical savings from customer responses to pricing signals are reflected in the load forecast.
	Inverted rate pricing	Energy and capacity impacts are not available/measured.	No. Historical savings from customer response to pricing structure is reflected in load forecast.
Education and Information	Energy education	Energy and capacity impacts are not available/measured.	No. Historical savings from customer participation are reflected in the load forecast.

[1/] A/C load control is based on long duration event characterization which assumes 50% cycling of ACs. A faster event (<1 hr) is characterized as 270 MW within the model.

Distributed Generation Forecast

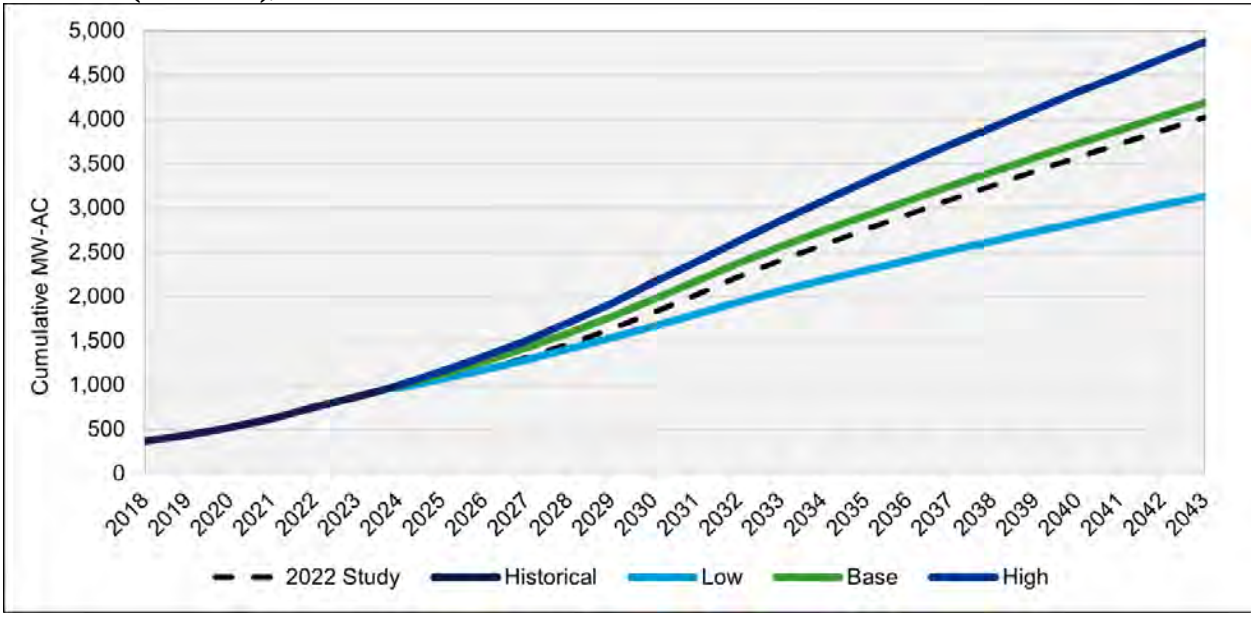
For the 2025 IRP, PacifiCorp contracted with DNV to update the assessment of distributed generation (DG)[2] penetration with new market, policy, and incentive developments.[3,4] The study provided a forecast of adoption of non-utility owned, behind-the-meter (BTM) customer generation resources in each of the six states served by PacifiCorp. Specific technologies studied included solar photovoltaic, photovoltaic solar coupled with battery storage, small-scale wind, small-scale hydro, and combined heat and power (CHP) for both reciprocating engines and micro-turbines.

[2] In the 2023 IRP, this study was referred to as the "Private Generation" assessment.
[3] See Appendix L (Distributed Generation Study).
[4] PacifiCorp's and DNV's decisions in the development of the DG study were topics of discussion in the 2025 IRP public input meeting series and stakeholder feedback.
See Appendix M, stakeholder feedback form #6 (Renewable Northwest).
See Appendix M, stakeholder feedback form #17 (Public Utility Commission of Oregon).
See Appendix M, stakeholder feedback form #26 (Vote Solar).

DNV estimates approximately 4.18 gigawatts (GW) of DG capacity will be installed in PacifiCorp's service area by 2043 in the base case scenario. As shown in Figure 6.1, the low and high scenarios project a cumulative installed capacity of 3.12 GW and 4.87 GW by 2043, respectively. The main drivers between the different scenarios include variation in technology costs, system performance, and electricity rate assumptions. The Inflation Reduction Act of 2022 (IRA) extends tax credits for distributed generation that creates favorable economics for adoption and is incorporated into each case. The DNV study identifies expected levels of customer-sited DG, which is applied as a reduction to PacifiCorp's forecasted load for IRP modeling purposes and informs customer cited demand response battery potential for the conservation potential assessment (CPA).

See Appendix L for the full DNV Distributed Generation report.

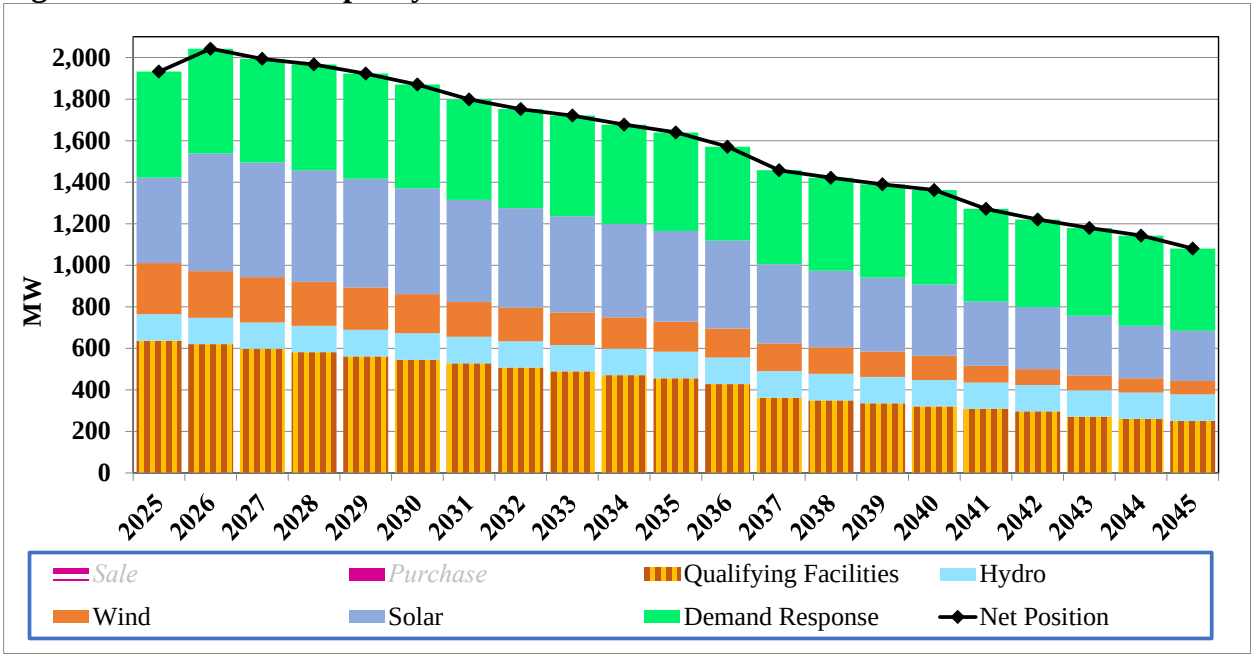
Figure 6.1 – Cumulative Historical and New Capacity Installed by Scenario (MW-AC), 2024-2043



Power-Purchase Agreements

PacifiCorp also meets capacity and energy requirements through long-term firm contracts. Figure 6.2 presents the contract capacity in place for 2025 through 2045. As shown, major capacity reductions in solar purchases, wind purchases, and QF contracts occur. For planning purposes, PacifiCorp assumes interruptible load contracts and demand response are extended through the end of the IRP study period. After their current contract terms, QF contracts are extended at a reduced level that reflects the historical renewal rate of 75%. All contracts are shown at their peak capacity contribution levels.

Figure 6.2 – Contract Capacity in the 2025 IRP Summer Load and Resource Balance



Capacity Load and Resource Balance

Capacity Balance Overview

The purpose of the load and resource balance is to compare annual obligations to the annual capability of PacifiCorp's existing resources after retirements and future energy efficiency savings from the 2025 IRP preferred portfolio, and without new generating resource additions.

The capacity balance compares generating capability to load obligations across both summer and winter. For the 2025 IRP, the load and resource balance use values from the Western Resource Adequacy Program (WRAP). WRAP calculates project-specific qualifying capacity contribution values for all existing and contracted resources, and those values are used where data is available. WRAP also provides the average contribution for wind, solar, energy storage and run of river hydro in different geographic areas, and these estimates are used for proxy resources in the 2025 IRP. WRAP will update the capacity contributions for resources ahead of each season, reflecting the current resource mix of the WRAP footprint through time. WRAP has also provided projections for future years and different resource penetration levels – as the penetration of wind, solar, and storage increases, contributions are expected to decline. Significant uncertainty remains, due to resource mix and timing, along with indirect factors like climate impacts on load and hydro. To better reflect future WRAP compliance requirements, PacifiCorp used the projections provided by WRAP to estimate contributions in 2045 based on the regional resource mix developed as part of the forward price curve used in the 2025 IRP. Because PacifiCorp is a relatively small portion of the regional resource mix, the calculation is static and does not vary with PacifiCorp's specific portfolio selections. WRAP contributions fall linearly from the current values for 2025 to the projected values for 2045. Additional detail is provided in Appendix K (Capacity Contribution).

For reporting purposes, the capacity balance summarized in this chapter is developed by first reducing the hourly system load by hourly distributed generation projections to determine the net

system coincident peak load for each of the first ten years (2025-2034) of the planning horizon. Then the annual firm capacity availability of the existing resources, reflecting assumed coal unit retirements from the preferred portfolio, is determined. Interruptible load programs, existing load reduction DSM programs, and new load reduction DSM programs from the preferred portfolio at the time of the net system coincident peak are included as part of the existing resources. The annual resource deficit or surplus is then computed by multiplying the obligation by the planning reserve margin (14.4% for the 2025 IRP, reflecting the WRAP value for the month of July) and then subtracting the result from existing resources. This view is presented both without and with uncommitted Market purchases.

The economics of adding resources to the system to meet both capacity and energy needs are addressed during the resource portfolio development process described in Chapter 8 (Modeling and Portfolio Evaluation Approach).

Load and Resource Balance Components

The main component categories consist of the following: resources, obligation, reserves, position, and available market purchases.

Under the calculations, there are negative values in the table in both the resource and obligation sections. This is consistent with how resource categories are represented in portfolio modeling. The resource categories include resources by type—coal, gas, hydroelectric, wind, solar, other renewables, storage, QFs, demand response, and purchases. Categories in the obligation section include load, distributed generation, and energy efficiency from the preferred portfolio.

Demand Response

Existing demand response program capacity is categorized as a resource. Under WRAP, demand response must be designated as either a load reduction, where any impacts are captured in peak loads, or as a resource, based on its availability and duration during peak conditions. For the 2025 IRP, demand response is used for operating reserves and dispatched within the PLEXOS model based on economic need and is not targeted to reduce summer-time peak loads which often occur during solar generation hours when net demand is lower. As a result, treatment as a resource provides a larger capacity benefit currently. PacifiCorp expects to continue evaluating this as the WRAP gets underway, as some demand response programs may be suitable for peak load reduction. Also included in the demand response category are interruptible contracts. PacifiCorp has had interruptible contracts with large load customers for many years. These contracts are a key aspect of the retail service provided to the associated customers, and absent these contracts their demand would likely be different from that included in the load forecast. To maintain an alignment with the load forecast, these contracts are assumed to continue indefinitely under their current structure.

Obligation

The obligation is the total electricity demand that PacifiCorp must serve, consisting of forecasted retail load less distributed generation and energy efficiency from the preferred portfolio. The following are descriptions of each of these components:

Load Net of Distributed generation

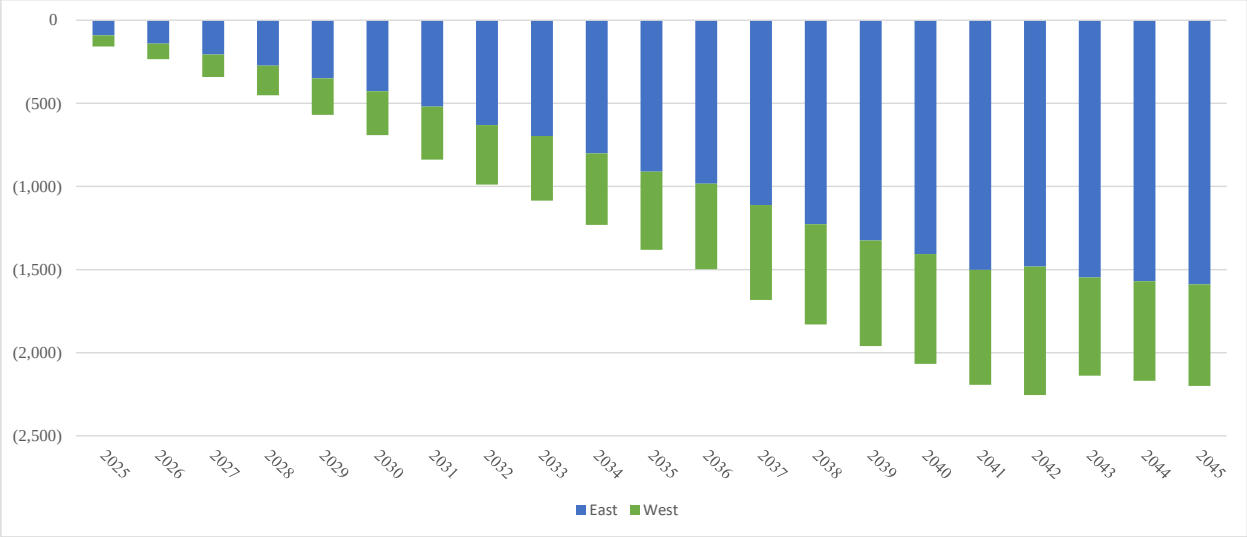
The largest component of the obligation is retail load. In the 2025 IRP, the hourly retail load at a location is first reduced by hourly distributed generation at the same location. The system

coincident peak is determined by summing the net loads for all locations (topology bubbles with loads) and then finding the highest hourly system load by year and season. Loads reported by east and west BAAs thus reflect loads at the time of PacifiCorp's coincident system summer and winter peaks.

Energy Efficiency

An adjustment is made to load to remove the projected embedded energy efficiency as a reduction to load. Due to timing issues with the vintage of the load forecast, there is a level of 2024 energy efficiency that is not incorporated in the forecast. The 2024 energy efficiency forecast has been added to the energy efficiency line along with the energy efficiency selected in the 2025 IRP preferred portfolio. Figure 6.3 shows the energy efficiency for the east and west control areas in the 2025 IRP preferred portfolio.

Figure 6.3 – Energy Efficiency Peak Contribution in Summer Capacity Load and Resource Balance (reduction to load, in MW)



Planning Reserve Margin

Planning reserve margin (PRM) represents an incremental capacity requirement, applied as an increase to the obligation to ensure that there will be sufficient capacity available on the system to manage uncertain events (i.e., weather, outages) and known requirements (i.e., operating reserves).

Position

The position is the resource surplus or deficit after subtracting obligation plus required reserves from total resources.

Capacity Balance Determination

Methodology

The capacity balance is developed by first determining the system coincident peak load for each of the first ten years of the planning horizon. Then the annual firm-capacity availability of the existing resources is determined for each of these annual system summer and winter peak periods, as applicable, and summed as follows:

Existing Resources = Coal + Gas + Hydro + Renewable + Storage + Firm Purchases + Qualifying Facilities + Demand Response

The peak load, distributed generation, energy efficiency (from the preferred portfolio) are netted together for each of the annual system summer and winter peaks, as applicable, to compute the annual peak obligation:

Obligation = Load – Distributed generation – Energy Efficiency

The level of reserves to be added to the obligation is then calculated. This is accomplished by taking the net system obligation calculated above multiplied by the 14.4 percent PRM for July and 16.8 percent PRM for December adopted from WRAP for the 2025 IRP. The formula for this calculation is:

Planning Reserves = Obligation x PRM

Finally, the annual capacity position is derived by adding the computed reserves to the obligation, and then subtracting this amount from existing resources, including available Market purchases, as shown in the following formula:

Capacity Position = (Existing Resources + Available Market purchases) – (Obligation + Planning Reserves)

Capacity Balance Results

Table 6.14 and Table 6.15 show the annual capacity balances and component line items for the summer peak and winter peak, respectively, using a target PRM of 14.4 percent in the summer and 16.8 percent in the winter to calculate the planning reserve amount.[5] Balances for PacifiCorp's system as well as the east and west control areas are shown. While east and west control area balances are broken out separately, the PacifiCorp system is planned for and dispatched on a system basis up to the limits of the transfer capability between the two areas. Also note that QF wind and solar projects listed earlier in the chapter are reported under the QF line item rather than the renewable, or other line items.

[5] PacifiCorp acknowledged errors in its 2023 IRP load and resource balance, which have been addressed in the 2025 IRP. See Appendix M, stakeholder feedback form #12 (Utah Association of Energy Users).

Table 6.14 -- Summer Peak – System Capacity Loads and Resources without Resource Additions

East	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	3,960	3,567	3,567	3,375	3,090	2,926	2,926	2,926	2,926	2,926
Gas	2,984	3,294	3,294	3,294	3,469	3,469	3,469	3,469	3,469	3,469
Hydroelectric	76	76	76	76	76	76	76	76	76	76
Wind	587	613	596	578	561	534	503	487	470	453
Solar	342	499	487	475	463	452	440	428	416	404
Other Renewable	46	45	44	42	41	40	39	37	36	35
Storage	1	939	925	909	894	879	865	849	834	819
Purchase	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	405	394	383	372	361	351	340	328	314	301
Demand Response	451	446	440	452	450	443	429	423	431	425
Sale	0	0	0	0	0	0	0	0	0	0
Transfers	(274)	(1,440)	(1,361)	(1,096)	(902)	(631)	(476)	(421)	(380)	(277)
East Existing Resources	**8,578**	**8,433**	**8,452**	**8,479**	**8,504**	**8,540**	**8,611**	**8,603**	**8,592**	**8,632**
Load	7,746	7,655	7,781	7,919	8,068	8,234	8,447	8,609	8,528	8,700
Distributed Generation	(157)	(143)	(186)	(234)	(285)	(341)	(400)	(458)	(321)	(354)
Energy Efficiency	(91)	(141)	(206)	(274)	(349)	(428)	(520)	(631)	(696)	(801)
East Total obligation	**7,498**	**7,372**	**7,388**	**7,412**	**7,433**	**7,465**	**7,527**	**7,520**	**7,511**	**7,545**
Planning Reserve Margin (14.4%)	1,080	1,062	1,064	1,067	1,070	1,075	1,084	1,083	1,082	1,087
East Obligation + Reserves	8,578	8,433	8,452	8,479	8,504	8,540	8,611	8,603	8,592	8,632
East Position	0	0	0	0	0	0	0	0	0	0
Available Market Purchases	500	500	500	0	0	0	0	0	0	0
West										
Coal	133	133	133	133	133	0	0	0	0	0
Gas	716	716	716	716	716	716	716	716	716	716
Hydroelectric	712	712	712	712	712	712	712	712	712	712
Wind	74	72	70	67	65	63	61	59	57	54
Solar	69	67	65	62	60	58	52	50	48	46
Other Renewable	0	0	0	0	0	0	0	0	0	0
Storage	2	1	1	1	1	1	1	1	1	0
Purchase	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	232	226	215	209	200	194	187	179	174	170
Demand Response	60	59	58	57	57	56	55	54	54	53
Sale	0	0	0	0	0	0	0	0	0	0
Transfers	274	1,440	1,361	1,096	902	631	476	421	380	277
West Existing Resources	**2,271**	**3,426**	**3,330**	**3,054**	**2,846**	**2,431**	**2,260**	**2,192**	**2,141**	**2,028**
Load	3,778	3,812	3,905	3,967	4,032	4,103	4,239	4,255	4,288	4,376
Distributed Generation	(49)	(54)	(75)	(99)	(124)	(152)	(182)	(213)	(132)	(148)
Energy Efficiency	(67)	(94)	(135)	(178)	(220)	(263)	(318)	(359)	(389)	(431)
West Total obligation	**3,662**	**3,664**	**3,695**	**3,690**	**3,688**	**3,688**	**3,738**	**3,684**	**3,767**	**3,798**
Planning Reserve Margin (14.4%)	527	528	532	531	531	531	538	530	542	547
West Obligation + Reserves	4,189	4,192	4,227	4,222	4,219	4,219	4,277	4,214	4,309	4,345
West Position	(1,918)	(766)	(898)	(1,168)	(1,373)	(1,788)	(2,016)	(2,022)	(2,168)	(2,317)
Available Market Purchases	2,603	2,603	2,603	0	0	0	0	0	0	0
System										
Total Resources	10,849	11,859	11,782	11,533	11,349	10,971	10,871	10,795	10,734	10,660
Obligation	11,160	11,036	11,084	11,102	11,121	11,153	11,265	11,203	11,278	11,343
Planning Reserves (14.4%)	1,607	1,589	1,596	1,599	1,601	1,606	1,622	1,613	1,624	1,633
Obligation + Reserves	12,767	12,625	12,680	12,701	12,723	12,759	12,887	12,817	12,902	12,977
System Position	(1,918)	(766)	(898)	(1,168)	(1,373)	(1,788)	(2,016)	(2,022)	(2,168)	(2,317)
Available Market Purchases	3,103	3,103	3,103	0	0	0	0	0	0	0
Uncommitted FOTs to meet remaining Need	1,918	766	898	0	0	0	0	0	0	0
Net Surplus/(Deficit)	0	0	0	(1,168)	(1,373)	(1,788)	(2,016)	(2,022)	(2,168)	(2,317)

Table 6.14 (cont.) – Summer Peak System Capacity Loads and Resources without Resource Additions

East	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	2,926	2,926	2,926	2,926	2,926	2,926	2,926	2,926	2,432	2,432	2,432
Gas	3,469	3,469	3,469	3,469	3,469	3,469	3,469	3,469	3,322	3,322	3,322
Hydroelectric	76	76	76	76	76	76	76	76	76	76	76
Wind	437	421	404	387	371	355	308	293	278	263	249
Solar	392	381	340	329	319	308	297	286	276	243	233
Other Renewable	33	32	31	12	11	10	10	9	9	8	0
Storage	804	788	773	759	744	728	714	699	684	668	654
Purchase	0	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	291	269	221	212	203	192	184	176	169	162	155
Demand Response	422	401	402	398	400	406	398	375	376	389	351
Sale	0	0	0	0	0	0	0	0	0	0	0
Transfers	(161)	0	0	0	0	0	0	0	0	0	0
East Existing Resources	**8,690**	**8,763**	**8,643**	**8,569**	**8,519**	**8,472**	**8,383**	**8,310**	**7,622**	**7,564**	**7,472**
Load	8,893	9,150	9,349	9,567	9,774	9,993	10,214	10,478	10,693	10,891	11,097
Distributed Generation	(385)	(415)	(445)	(474)	(503)	(529)	(557)	(584)	(609)	(635)	(660)
Energy Efficiency	(911)	(983)	(1,112)	(1,227)	(1,325)	(1,407)	(1,501)	(1,482)	(1,547)	(1,570)	(1,588)
East Total obligation	**7,596**	**7,752**	**7,792**	**7,865**	**7,946**	**8,057**	**8,156**	**8,413**	**8,536**	**8,686**	**8,848**
Planning Reserve Margin (14.4%)	1,094	1,116	1,122	1,133	1,144	1,160	1,174	1,211	1,229	1,251	1,274
East Obligation + Reserves	8,690	8,869	8,914	8,998	9,090	9,217	9,330	9,624	9,766	9,937	10,123
East Position	0	(105)	(271)	(429)	(571)	(745)	(947)	(1,314)	(2,144)	(2,373)	(2,650)
Available Market Purchases	0	0	0	0	0	0	0	0	0	0	0
West											
Coal	0	0	0	0	0	0	0	0	0	0	0
Gas	716	716	716	716	716	716	716	716	716	716	716
Hydroelectric	712	712	712	712	712	712	712	712	712	712	712
Wind	52	50	48	46	44	41	39	37	35	33	31
Solar	45	43	41	39	37	35	13	12	11	11	10
Other Renewable	0	0	0	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0	0	0	0
Purchase	0	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	165	160	142	138	132	128	124	120	101	97	95
Demand Response	52	51	51	50	49	48	48	47	46	45	44
Sale	0	0	0	0	0	0	0	0	0	0	0
Transfers	161	0	0	0	0	0	0	0	0	0	0
West Existing Resources	**1,902**	**1,731**	**1,708**	**1,700**	**1,689**	**1,681**	**1,651**	**1,644**	**1,621**	**1,613**	**1,608**
Load	4,475	4,577	4,692	4,807	4,927	5,049	5,173	5,376	5,430	5,553	5,680
Distributed Generation	(163)	(177)	(192)	(206)	(221)	(234)	(249)	(263)	(277)	(290)	(304)
New Energy Efficiency	(471)	(515)	(571)	(603)	(634)	(661)	(691)	(774)	(591)	(599)	(612)
West Total obligation	**3,841**	**3,885**	**3,929**	**3,998**	**4,073**	**4,154**	**4,233**	**4,340**	**4,562**	**4,663**	**4,764**
Planning Reserve Margin (14.4%)	553	559	566	576	586	598	609	625	657	671	686
West Obligation + Reserves	4,394	4,444	4,495	4,574	4,659	4,752	4,842	4,965	5,219	5,334	5,450
West Position	(2,492)	(2,713)	(2,787)	(2,874)	(2,970)	(3,072)	(3,191)	(3,321)	(3,598)	(3,721)	(3,842)
Available Market Purchases	0	0	0	0	0	0	0	0	0	0	0
System											
Total Resources	10,592	10,494	10,351	10,269	10,209	10,152	10,034	9,954	9,243	9,178	9,080
Obligation	11,438	11,637	11,721	11,863	12,019	12,211	12,388	12,753	13,099	13,349	13,612
Planning Reserves (14.4%)	1,647	1,676	1,688	1,708	1,731	1,758	1,784	1,836	1,886	1,922	1,960
Obligation + Reserves	13,085	13,313	13,409	13,572	13,750	13,969	14,172	14,589	14,985	15,272	15,573
System Position	(2,492)	(2,818)	(3,058)	(3,303)	(3,541)	(3,817)	(4,138)	(4,635)	(5,742)	(6,094)	(6,493)
Available Market Purchases	0	0	0	0	0	0	0	0	0	0	0
Uncommitted FOTs to meet remaining Need	0	0	0	0	0	0	0	0	0	0	0
Net Surplus/(Deficit)	(2,492)	(2,818)	(3,058)	(3,303)	(3,541)	(3,817)	(4,138)	(4,635)	(5,742)	(6,094)	(6,493)

Table 6.15 – Winter Peak System Capacity Loads and Resources without Resource Additions

East	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	4,147	3,734	3,734	3,499	3,185	3,015	3,015	3,015	3,015	3,015
Gas	3,003	3,334	3,334	3,335	3,526	3,527	3,527	3,527	3,527	3,527
Hydroelectric	33	33	33	33	33	33	33	33	33	33
Wind	1,837	1,957	1,892	1,829	1,766	1,657	1,523	1,463	1,404	1,346
Solar	38	104	101	98	95	92	89	85	82	79
Other Renewable	41	39	38	37	35	34	33	32	30	29
Storage	1	621	606	591	576	561	546	531	516	500
Purchase	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	186	181	176	171	166	161	156	149	140	124
Demand Response	119	118	118	128	129	128	121	120	128	127
Sale	0	0	0	0	0	0	0	0	0	0
Transfers	(1,600)	(1,600)	(1,600)	(1,600)	(1,600)	(1,600)	(1,600)	(1,585)	(1,353)	(1,118)
East Existing Resources	**7,804**	**8,523**	**8,433**	**8,120**	**7,911**	**7,608**	**7,442**	**7,369**	**7,522**	**7,662**
Load	5,898	5,911	6,036	6,164	6,278	6,408	6,569	6,706	6,899	7,084
Distributed Generation	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Energy Efficiency	(75)	(118)	(157)	(197)	(239)	(283)	(331)	(388)	(450)	(513)
East Total obligation	**5,821**	**5,790**	**5,876**	**5,963**	**6,033**	**6,119**	**6,231**	**6,309**	**6,440**	**6,560**
Planning Reserve Margin (16.8%)	978	973	987	1,002	1,014	1,028	1,047	1,060	1,082	1,102
East Obligation + Reserves	6,799	6,763	6,863	6,964	7,047	7,147	7,278	7,369	7,522	7,662
East Position	1,005	1,760	1,570	1,156	864	461	164	0	0	0
Available Market Purchases	500	500	500	0	0	0	0	0	0	0
West										
Coal	147	147	147	147	147	0	0	0	0	0
Gas	735	735	735	735	735	735	735	735	735	735
Hydroelectric	726	726	726	726	726	726	726	726	726	726
Wind	64	62	59	57	55	53	51	49	47	45
Solar	1	1	1	1	1	1	0	0	0	0
Other Renewable	0	0	0	0	0	0	0	0	0	0
Storage	2	2	2	2	2	2	2	2	2	0
Purchase	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	70	69	62	61	58	57	57	56	56	56
Demand Response	0	0	0	0	0	0	0	0	0	0
Sale	0	0	0	0	0	0	0	0	0	0
Transfers	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,585	1,353	1,118
West Existing Resources	**3,345**	**3,342**	**3,333**	**3,330**	**3,325**	**3,174**	**3,171**	**3,153**	**2,919**	**2,679**
Load	3,511	3,571	3,640	3,701	3,741	3,805	3,904	3,981	4,068	4,160
Distributed Generation	(0)	(0)	(1)	(1)	(1)	(1)	(1)	(2)	(2)	(2)
Energy Efficiency	(52)	(65)	(118)	(173)	(229)	(286)	(345)	(401)	(457)	(511)
West Total obligation	**3,459**	**3,506**	**3,521**	**3,527**	**3,511**	**3,517**	**3,558**	**3,578**	**3,609**	**3,647**
Planning Reserve Margin (16.8%)	581	589	591	593	590	591	598	601	606	613
West Obligation + Reserves	4,041	4,095	4,112	4,120	4,101	4,108	4,156	4,180	4,215	4,259
West Position	(696)	(753)	(780)	(790)	(776)	(934)	(985)	(1,027)	(1,297)	(1,581)
Available Market Purchases	2,603	2,603	2,603	0	0	0	0	0	0	0
System										
Total Resources	11,149	11,865	11,766	11,450	11,235	10,783	10,613	10,522	10,441	10,341
Obligation	9,281	9,296	9,397	9,490	9,544	9,636	9,789	9,888	10,049	10,207
Planning Reserves (16.8%)	1,336	1,339	1,353	1,367	1,374	1,388	1,410	1,424	1,447	1,470
Obligation + Reserves	10,617	10,635	10,750	10,857	10,918	11,024	11,199	11,312	11,497	11,677
System Position	532	1,230	1,016	594	317	(241)	(586)	(789)	(1,056)	(1,336)
Available Market Purchases	3,103	3,103	3,103	0	0	0	0	0	0	0
Uncommitted FOTs to meet remaining Need	0	0	0	0	0	0	0	0	0	0
Net Surplus/(Deficit)	532	1,230	1,016	594	317	(241)	(586)	(789)	(1,056)	(1,336)

Table 6.15 (cont.) – Winter Peak System Capacity Loads and Resources without Resource Additions

East	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	3,015	3,015	3,015	3,015	3,015	3,015	3,015	3,015	2,503	2,503	2,503
Gas	3,527	3,527	3,527	3,527	3,527	3,527	3,527	3,527	3,378	3,378	3,378
Hydroelectric	33	33	33	33	33	33	33	33	33	33	33
Wind	1,285	1,226	1,168	1,107	1,049	990	850	797	744	689	636
Solar	76	73	70	67	64	61	58	55	52	42	39
Other Renewable	28	26	25	9	8	8	7	7	6	6	0
Storage	485	470	455	440	425	410	395	379	365	350	334
Purchase	0	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	120	112	99	94	90	86	82	78	75	71	67
Demand Response	128	117	121	121	125	132	129	117	121	132	109
Sale	0	0	0	0	0	0	0	0	0	0	0
Transfers	(919)	(674)	(414)	(137)	0	0	0	0	0	0	0
East Existing Resources	**7,778**	**7,925**	**8,097**	**8,275**	**8,336**	**8,262**	**8,096**	**8,008**	**7,276**	**7,204**	**7,101**
Load	7,248	7,421	7,645	7,863	8,087	8,287	8,466	8,705	8,909	9,134	9,224
Distributed Generation	(11)	(11)	(12)	(13)	(13)	(14)	(14)	(14)	(15)	(15)	(16)
Energy Efficiency	(579)	(624)	(700)	(766)	(826)	(886)	(954)	(973)	(1,022)	(1,049)	(1,077)
East Total obligation	**6,659**	**6,786**	**6,932**	**7,084**	**7,248**	**7,387**	**7,498**	**7,717**	**7,872**	**8,070**	**8,131**
Planning Reserve Margin (16.8%)	959	977	998	1,020	1,044	1,064	1,080	1,111	1,134	1,162	1,171
East Obligation + Reserves	7,618	7,763	7,931	8,105	8,292	8,451	8,578	8,828	9,005	9,232	9,302
East Position	160	163	166	170	44	(189)	(482)	(820)	(1,729)	(2,028)	(2,201)
Available Market Purchases	0	0	0	0	0	0	0	0	0	0	0
West											
Coal	0	0	0	0	0	0	0	0	0	0	0
Gas	735	735	735	735	735	735	735	735	735	735	735
Hydroelectric	726	726	726	726	726	726	726	726	726	726	726
Wind	42	40	38	36	34	32	30	28	25	23	21
Solar	0	0	0	0	0	0	0	0	0	0	0
Other Renewable	0	0	0	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0	0	0	0
Purchase	0	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	55	54	53	53	51	51	50	50	50	49	49
Demand Response	0	0	0	0	0	0	0	0	0	0	0
Sale	0	0	0	0	0	0	0	0	0	0	0
Transfers	919	674	414	137	0	0	0	0	0	0	0
West Existing Resources	**2,478**	**2,229**	**1,967**	**1,687**	**1,546**	**1,544**	**1,541**	**1,539**	**1,536**	**1,534**	**1,531**
Load	4,232	4,334	4,471	4,605	4,720	4,832	4,959	5,143	5,253	5,374	5,365
Distributed Generation	(2)	(3)	(3)	(3)	(3)	(3)	(3)	(4)	(4)	(4)	(4)
Energy Efficiency	(568)	(624)	(668)	(714)	(760)	(819)	(858)	(900)	(786)	(803)	(826)
West Total obligation	**3,662**	**3,707**	**3,800**	**3,888**	**3,957**	**4,010**	**4,097**	**4,239**	**4,463**	**4,567**	**4,535**
Planning Reserve Margin (16.8%)	615	623	638	653	665	674	688	712	750	767	762
West Obligation + Reserves	4,277	4,330	4,438	4,541	4,622	4,684	4,786	4,952	5,212	5,334	5,297
West Position	(1,799)	(2,100)	(2,471)	(2,854)	(3,075)	(3,140)	(3,245)	(3,413)	(3,676)	(3,801)	(3,766)
Available Market Purchases	0	0	0	0	0	0	0	0	0	0	0
System											
Total Resources	10,255	10,155	10,064	9,962	9,882	9,806	9,637	9,547	8,812	8,737	8,632
Obligation	10,321	10,493	10,732	10,973	11,205	11,398	11,596	11,957	12,334	12,637	12,666
Planning Reserves (16.8%)	1,486	1,511	1,545	1,580	1,614	1,641	1,670	1,722	1,776	1,820	1,824
Obligation + Reserves	11,807	12,003	12,278	12,553	12,819	13,039	13,265	13,678	14,110	14,456	14,490
System Position	(1,552)	(1,849)	(2,214)	(2,591)	(2,937)	(3,233)	(3,628)	(4,132)	(5,298)	(5,719)	(5,858)
Available Market Purchases	0	0	0	0	0	0	0	0	0	0	0
Uncommitted FOTs to meet remaining Need	0	0	0	0	0	0	0	0	0	0	0
Net Surplus/(Deficit)	(1,552)	(1,849)	(2,214)	(2,591)	(2,937)	(3,233)	(3,628)	(4,132)	(5,298)	(5,719)	(5,858)

Figure 6.4 through Figure 6.7 are graphic representations of the above tables for annual capacity position for the summer system, winter system, east control area, and west control area. Also shown in the system capacity position graph are available Market purchases, which can be used

to meet capacity needs. The market availability assumptions used for portfolio modeling are discussed further in Chapter 7 (Resource Options).

Figure 6.4 – Summer System Capacity Position Trend

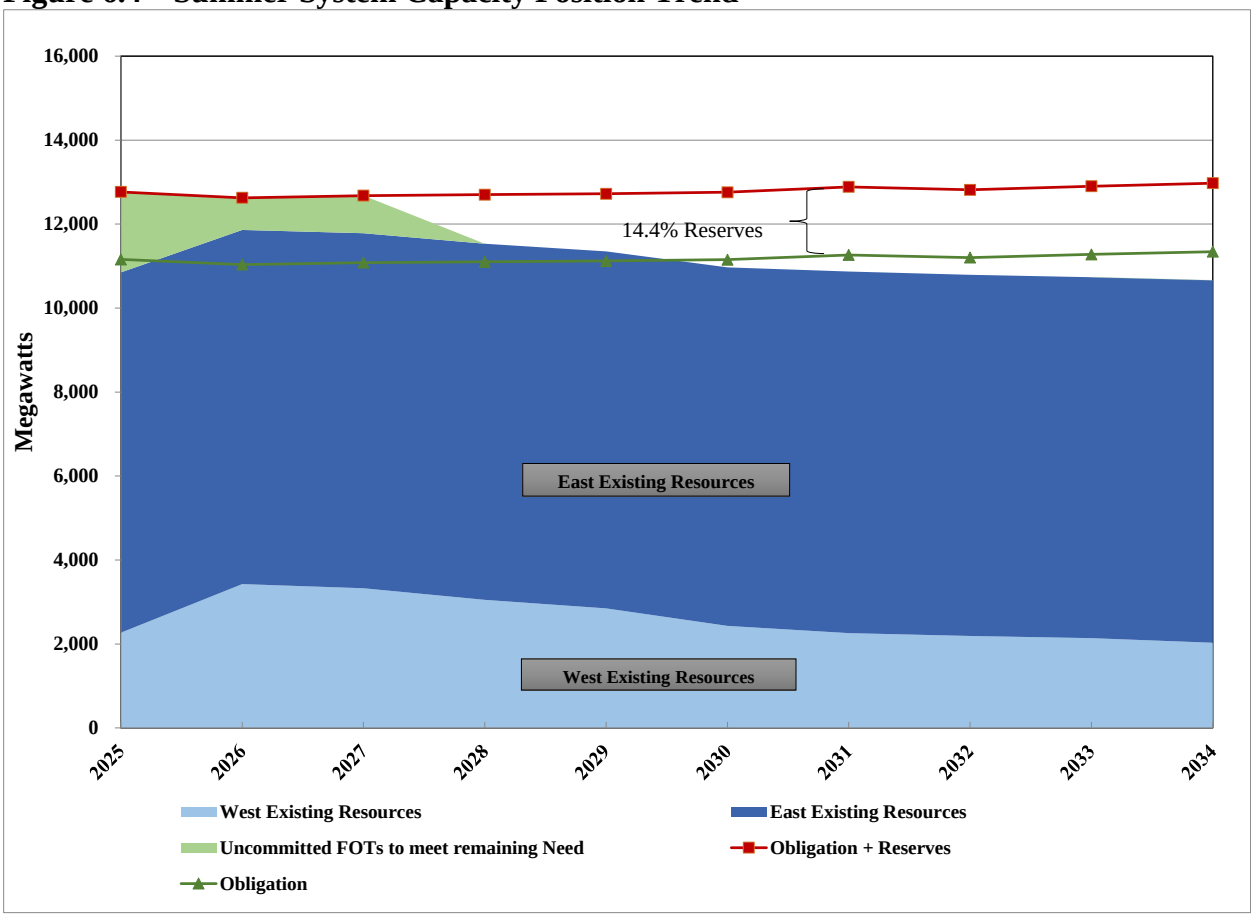


Figure 6.5 – Winter System Capacity Position Trend

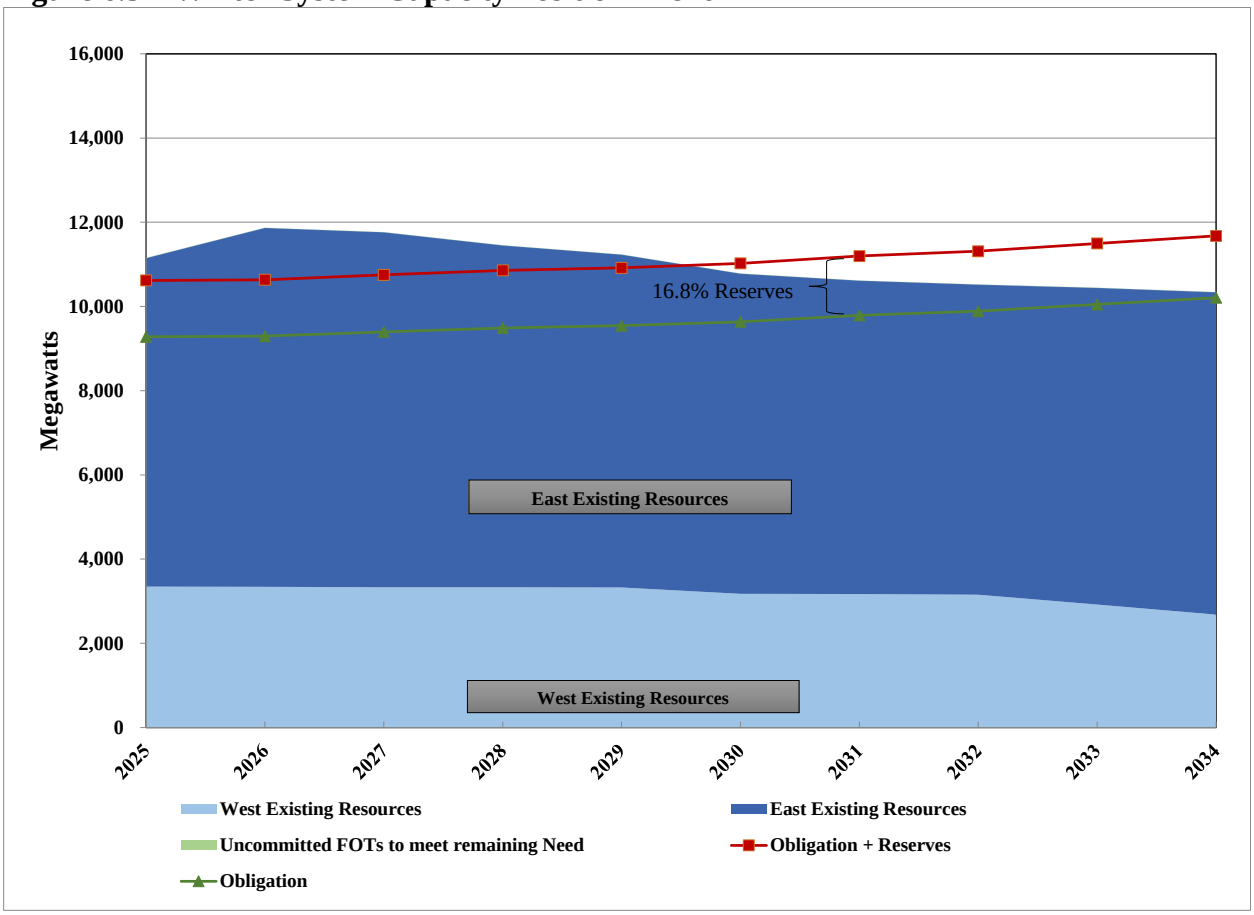


Figure 6.6 – East Summer Capacity Position Trend

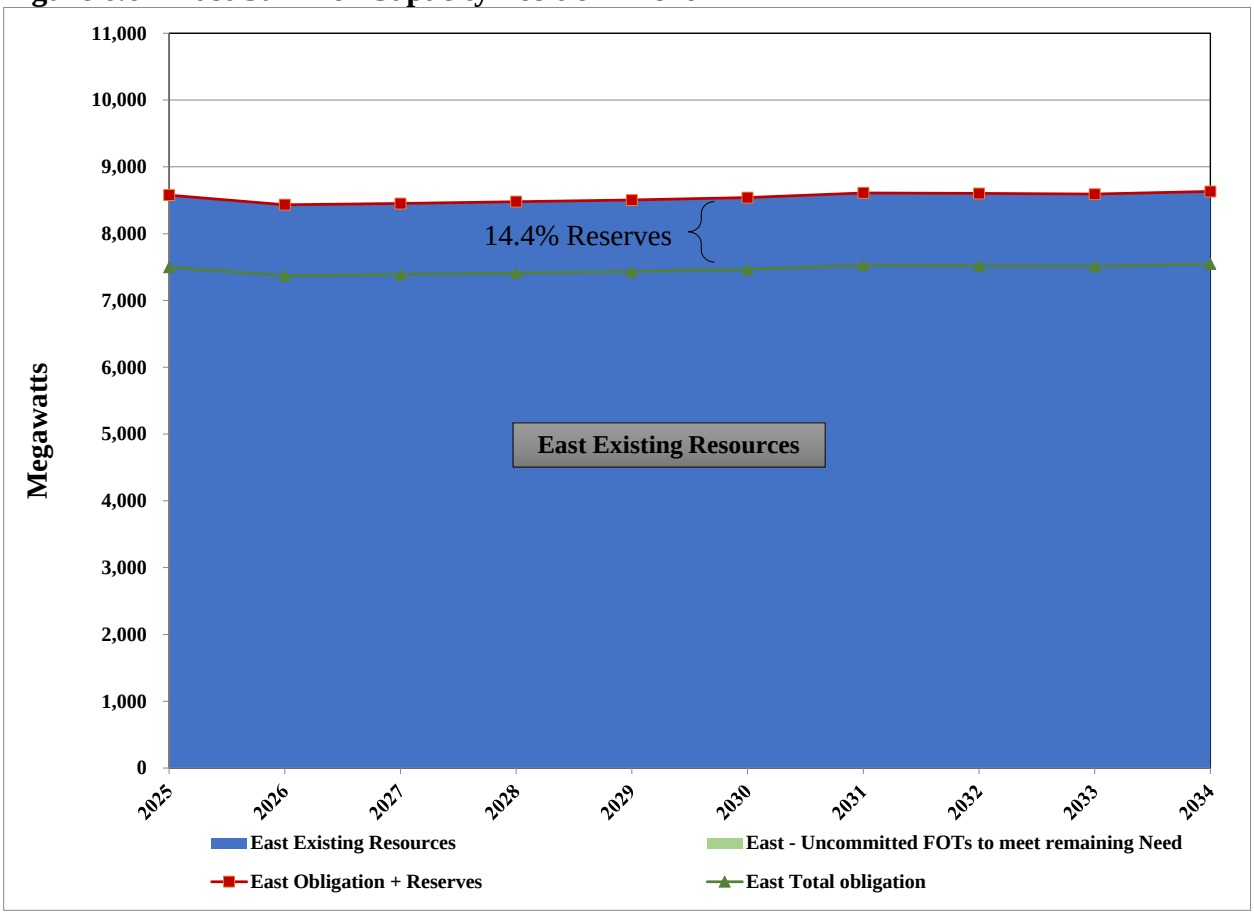
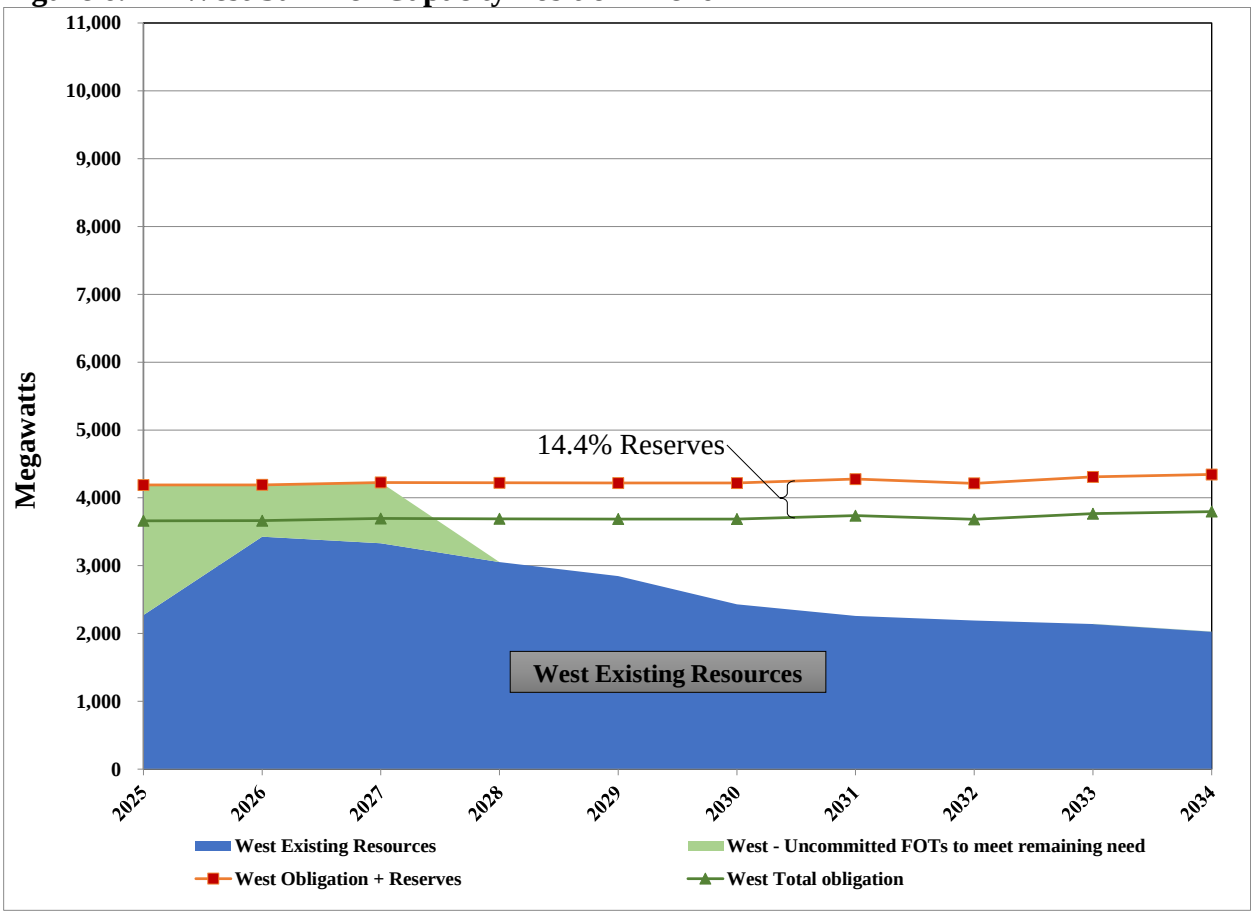


Figure 6.7 – West Summer Capacity Position Trend



CHAPTER 7 – RESOURCE OPTIONS

CHAPTER HIGHLIGHTS

- PacifiCorp's resource attributes and costs for future generation resource options reflect updated information, based on assumptions from the National Renewable Energy Laboratory's 2024 Annual Technology Baseline to the extent data was available.[1]
- In addition to utility-scale resources (generally 200 megawatts (MW) or more), the 2025 IRP includes small-scale (20 MW) wind, solar, and biodiesel peaking options. These small-scale resource options are assumed to be sited in relative proximity to load, such that they do not require significant transmission system upgrades.
- Renewable resource generation profiles have been updated and expanded to include more proxy resource locations as well as distinct profiles for utility-scale and small-scale wind resources, rather than one generation profile per state as in the 2023 IRP. This update extends to online and contracted resources, as well as proxy resource options, and includes expanded historical data for use with stochastic analysis.
- Options for utility-scale lithium-ion batteries (20 MW and 200 MW options), gravity energy storage systems, pumped hydro energy storage (PHES), thermal energy storage, one-hundred-hour iron-air storage, and adiabatic compressed air energy storage are included in this IRP. In a change from prior IRPs, hydrogen peaking resources are also treated as storage resources (rather than using pipelines and a market price for hydrogen). Hydrogen is electrolyzed using excess generation output and stored in either high-pressure tanks or underground caverns.
- PLEXOS endogenously models transmission upgrades, allowing for increases to transfer limits and resource interconnection. Where applicable, upgrades are restricted until all pre-requisites are in place.
- PacifiCorp continues to apply cost reduction credits to energy efficiency, reflecting risk mitigation benefits, transmission and distribution investment deferral benefits, and a ten percent market price credit for Washington and Oregon as allowed by the Northwest Power Act.

Introduction

This chapter provides background information on the various resources considered in the IRP for meeting future capacity and energy needs. Organized by major category, these resources consist of utility-scale supply-side generation, demand-side management (DSM) programs, transmission resources and market purchases. For each resource category, the chapter discusses the criteria for resource selection, presents the options and associated attributes, and describes the various technologies. In addition, for supply-side resources, the chapter describes how PacifiCorp addressed long-term cost trends and uncertainty in deriving cost figures.

[1] https://atb.nrel.gov/electricity/2024/index

Supply-Side Resources

The list of supply-side resource options reflects the expected realities evidenced through external studies, internally generated studies, permitting, regulatory requirements, and stakeholder input. The process began with the list of major generating resources from the 2023 IRP. This resource list was reviewed and modified to reflect stakeholder input, new technology developments, environmental factors, cost dynamics and anticipated permitting requirements. The National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB)[2] was used as much as possible to maintain consistency. Some of the terminology used in this chapter is from the ATB. A glossary of some of the terminology is provided below in Table 7.12 and a list of acronyms is provided in Table 7.13.

The supply-side resource options include the following technologies grouped by energy source. More information about each technology is provided in the "Resource Option Descriptions" section of this chapter. The terminology here matches that used in the supply-side resource table, although some may have been shortened per the acronym list in Table 7.13.

- Natural Gas
  - Internal Combustion Engines.
  - SCCT, Aero, & F-Frame.
  - CCCT, 1x1, & 2x1.
    - Adjustments for 95% Carbon Capture.
    - Adjustments for Brownfield Construction.
    - Adjustments for advanced technology innovation scenario ("Innovations far from market-ready today are successful and become widespread in the market. New technology architectures could look different from those observed today. Public and private R&D investment increases. For biopower technologies, technology cost designations appearing in ATB tables and figures refer to technology assumptions and the range of fuel price projections as described on their respective technology pages."[3])
- Hydrogen
  - Adjustments for 100% Hydrogen burning capability.
  - Adjustments for Hydrogen Storage.
  - Electrolyzer.
- Coal, Carbon Capture Retrofits at existing plants
- Energy Storage
  - Lithium-Ion Batteries (20 MW, 200 MW, and 1,000 MW all with 4-hour duration):
    - Adjustments for double duration (i.e., 8-hour duration).
    - Adjustments for co-location with other generating resources.
    - Adjustments for advanced technology innovation scenario.
  - Gravity Batteries.
  - Adiabatic Compressed Air Energy Storage (ACAES).
  - 100-Hour Iron Air Batteries.
  - PHES (single and double reservoirs).
  - Pumped Thermal.
- Solar

[2] https://atb.nrel.gov/electricity/2024/definitions#scenarios
[3] https://atb.nrel.gov/electricity/2024/definitions#scenarios

    - Adjustments for advanced technology innovation scenario.
- Wind (various on-shore wind classes and off-shore class 12, as appropriate for PacifiCorp's service area)
    - Adjustments for advanced technology innovation scenario.
- Nuclear[4]
    - Small Modular Reactor.
        - Adjustments for adding thermal energy storage.
    - Large Light Water Reactor.
        - Adjustments for advanced technology innovation scenario (in addition to the earlier definition: "for nuclear technologies, technology cost designations appearing in ATB tables and figures refer to technology assumptions and the range of fuel price projections as described on their respective technology pages.")
- Geothermal (near field enhanced geothermal system, binary)
    - Adjustments for advanced technology innovation scenario.

Derivation of Resource Attributes

Once a basic list of resources was determined, the cost-and-performance attributes for each resource were estimated. The information sources used are listed below, followed by a brief description on how they were used in the development of the supply-side resource table, which is used to develop inputs for IRP modeling:

- Annual Technology Baseline (ATB) prepared by the National Renewable Energy Laboratory (NREL).[5]
- U.S. Energy Information Administration (EIA) "Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies" ("EIA Report," both the 2024[6] and 2020[7] editions) prepared by Sargent and Lundy.
- Original equipment manufacturers capital and operation and maintenance estimates.
- Developer cost and performance estimates.
- Publicly available cost and performance estimates.
- Actual PacifiCorp or electric utility industry installations, providing current construction/maintenance costs and performance data with similar resource attributes.
- Projected PacifiCorp or electric utility industry installations, providing projected construction/maintenance costs and performance data of similar or identical resource options.
- Additional references are provided in the Resource Option Descriptions section of this chapter.

[4] Nuclear technology is intentionally limited to years outside the 2-4 year action plan window. Nuclear resource assumptions were discussed in the 2025 IRP public input meeting series and stakeholder feedback,
See Appendix M, stakeholder feedback form #1 (Peter Gross).
See Appendix M, stakeholder feedback form #41 (Nathan Strain).

[5] https://atb.nrel.gov/electricty/2024/index.

[6] *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies*, December 6, 2023, Sargent & Lundy, prepared for the U.S. Energy Information Administration's *Capital Cost and Performance Characteristics for Utility Scale Electric Power Generating Technologies*, January 2024 https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf.

[7] *Cost and Performance Estimates for New Utility-Scale Electric Power Generating Technologies*, December 2019, Sargent & Lundy, prepared for the U.S. Energy Information Administration's *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies*, February 2020 https://www.eia.gov/analysis/studies/powerplants/capitalcost/archive/2020/pdf/capital_cost_AEO2020.pdf.

Most of the supply-side resource options rely on the ATB and EIA reports. Some resources contained in the supply-side resource table are not listed in the ATB, but were developed through other reports, conversations with industry experts, developers, and original equipment manufacturers (OEM's). The 2024 ATB with its numerous references and the 2024 EIA Report was used for:

- Natural Gas
  - SCCT (Aero).
  - CCCT (1x1 & 2x1).
    - Adjustments for 95% Carbon Capture.
    - Adjustments for advanced technology innovation scenario.
- Energy Storage
  - Lithium-Ion Batteries (20 MW, 200 MW, and 1,000 MW, 4-hour duration).
    - Adjustments for double duration.
    - Adjustments for co-location.
    - Adjustments for advanced technology innovation scenario.
  - PHES (single and double reservoirs).
- Solar
  - Adjustments for advanced technology innovation scenario.
- Wind
  - Adjustments for advanced technology innovation scenario.
- Nuclear
  - Small Modular Reactor.
  - Large Light Water Reactor.
  - Adjustments for advanced technology innovation scenario.
- Geothermal (near field enhanced geothermal system, binary)
  - Adjustments for advanced technology innovation scenario.

The 2020 EIA Report provided the Internal Combustion Engines (ICE) data because no ICE option was included in the 2024 EIA report. The ICE option was included to address Oregon requirements for small-scale resources under 20 MW. Although the ICE option consists of 4 x 5.6 MW engines at ISO conditions, it is assumed that the engines, if not derated due to altitude or other factors, can be curtailed to meet the 20 MW threshold.

The brownfield cost adjustment was developed based on prior IRP estimates.

Hydrogen capable resource data is based on the following:[8]

- Adjustments for 100% hydrogen burning capability are based on conversations with OEMs and industry experts and the report "Exploring the competitiveness of hydrogen-fueled gas turbines in future energy systems."[9] A 15% cost adder for new gas turbines indicated by Table 3 in the report was corroborated by OEMs and other industry experts.

[8] The option of hydrogen as an alternative fuel, including electrolyzer cost and performance, was discussed in the course of the 2025 IRP public input meeting series. For specific recommendations and PacifiCorp's response, see Appendix M, stakeholder feedback form #23 (NP Energy, LLC)

[9] Simon Oberg, Mikael Odenberger, Filip Johnsson "Exploring the competitiveness of hydrogen-fueled gas turbines in future energy systems," Division of Energy Technology, Chalmers University of Technology, 412 96, Gothenburg, Sweden, https://www.sciencedirect.com/science/article/pii/S0360319921039768

- Adjustments for hydrogen storage are based on information in the U.S. Department of Energy (DOE) reports: "Pathways to Commercial Liftoff: Clean Hydrogen"[10] (Clean Hydrogen Liftoff report), "2022 Grid Energy Storage Technology Cost and Performance Assessment,"[11] and the Hydrogen and Fuel Cell Technologies Office's "Multi-Year Program Plan."[12]
- Electrolyzer costs are based on the DOE report "Hydrogen Production Cost from PEM Electrolysis – 2019,"[13] and the NREL report "Updated Manufactured Cost Analysis for Proton Exchange Membrane Water Electrolyzers."

Data for "Carbon Capture Retrofits at existing coal plants" is based on adjustments made to incorporate capital and operational costs of emission control technologies (SCR and FGD) needed to scrub flue gas prior to the carbon capture technology, and adjustments made to account for economies of scale.

Gravity Batteries costs were escalated from the 2023 IRP.

Adiabatic Compressed Air Energy Storage (ACAES) were originally escalated from the 2023 IRP which used data provided by Renewable Energy Storage Company (RESC) but later updated based on input from Hydrostor.

100-Hour Iron Air Battery data is based on information provided by Form Energy.[14]

Pumped Thermal energy storage is based on integrated thermal storage for nuclear, but with a resistive heater for energy storage.

Data for "Adjustments for adding thermal energy storage to nuclear plants" represents thermal energy storage and only stores energy from the heat of the reactor, not from a resistive heater.
The following costs were excluded from the cost estimates provided by the referenced sources, but were added by the Company as appropriate, using confidential data specific to the Company's business practices:[15]

- Allowance for Funds Used During Construction (AFUDC).
- Capital Surcharge.
- Escalation.
- Property taxes.

Interconnection costs and sales tax are included in the PLEXOS modeling depending on the locational node in which each technology is being considered.

[10] https://liftoff.energy.gov/
[11] https://www.energy.gov/sites/default/files/2022-09/2022%20Grid%20Energy%20Storage%20Technology%20Cost%20and%20Performance%20Assessment.pdf
[12] https://www.energy.gov/sites/default/files/2024-05/hfto-mypp-2024.pdf
[13] https://www.hydrogen.energy.gov/docs/hydrogenprogramlibraries/pdfs/19009_h2_production_cost_pem_electrolysis_2019.pdf?Status=Master
[14] See Appendix M, stakeholder feedback form #49 (Utah Association of Energy Users).
[15] Additional cost considerations were the subject of discussion and feedback during the 2025 IRP public input meeting series. See Appendix M, stakeholder feedback form #24 (NP Energy, LLC).

Wind and Solar Generation Profiles

For the 2025 IRP, PacifiCorp has updated the wind and solar generation profiles for both existing resources and proxy resource options. PacifiCorp provided the location and expected generation levels for existing and contracted resources to a consultant, Hendrickson Renewables, and received back an hourly generation profile for 2006-2023 that reflects expected performance under historical weather conditions.

For existing resources, results were tuned to recent historical actual generation levels, while resources that are not yet operating were tuned to forecasted output. For wind, hourly generation is based on hourly wind speeds and air density from the ERA5 reanalysis dataset, with scaling and adjustments to represent project-specific power curves and expected output.[16] For solar, hourly solar irradiance and weather data was extracted from a Vaisala satellite irradiance dataset[17] and configured in a PV_{syst} model[18] that was tuned to correspond to actual or forecasted output.

For proxy resources, PacifiCorp identified locations across its system, and Hendrickson Renewables determined the expected output of the equipment represented in NREL's ATB, which was used to develop cost inputs. In the 2023 IRP, PacifiCorp used one wind and solar profile for each of its five largest state jurisdictions (excluding California). For the 2025 IRP, wind and solar profiles have been developed which to correspond to thirteen different transmission areas spread across PacifiCorp's system. To account for technological differences that impact generation output, generation profiles were also developed for five small-scale wind profiles for the west side of the system, along with an off-shore wind profile for the potential lease area near Brookings.[19]

For many years, PacifiCorp has used a chaotic normal load forecast to account for the range of load conditions experienced. For each month of the year, the chaotic normal load forecast is derived from the most representative historical month from recent history (currently 2013-2022). The pattern of load in each of the selected months from history is reflected in every year of the forecast, with adjustments to account for the rotation of calendar days and weekdays from year to year, as well as for forecasted changes in load over time. As a result, every day of PacifiCorp's load forecast is tied to a specific day in history. For the 2025 IRP, the normalized wind and solar output modeled in PLEXOS is drawn from the same historical day as the load forecast. The result is a generation profile specific to each of the years of the IRP forecast (2025-2045) that inherently represents the correlation between renewable generation and load. The expanded historical generation data set developed for the 2025 IRP also enables stochastic analysis that captures the relationship between renewable generation and load in each of the historical years (2006-2023).

Natrium Demonstration Project

PacifiCorp's 2025 IRP includes the Natrium® advanced nuclear demonstration project: an 840 megawatt thermal pool-type sodium fast reactor that contains a compact and simple safety envelope and a molten salt energy storage system which enables the plant to vary its supply of energy to the grid, up to 500 megawatts electric net, providing both firm and flexible emissions-free energy. The reactor operates near atmospheric pressure, circulating sodium through its core

[16] European Centre for Medium-Range Weather Forecasts.https://www.ecmwf.int/en/forecasts/dataset/ecmwf-reanalysis-v5
[17] Vaisala. https://www.vaisala.com/
[18] PV_{syst}. https://www.pvsyst.com/
[19] Bureau of Ocean Energy Management. https://www.boem.gov/renewable-energy/state-activities/Oregon

with pumps. The design includes reliable inherent and passive safety features including near atmospheric operating pressures, always-on passive air cooling and inherent reactivity feedback.

At this time, the specific cost and performance assumptions for the Natrium® advanced nuclear demonstration project are confidential and are not summarized in the supply-side resource table. TerraPower and PacifiCorp remain committed to bringing the Natrium technology to market to enhance the company's ability to serve its customers, meet growing demand and ensure a reliable and resilient energy future. PacifiCorp is also committed to protecting customers from first-of-a-kind (FOAK) technology risk and FOAK program and construction costs. The Company is implementing an innovative commercial energy acquisition structure that allows Natrium benefits to flow to customers while ensuring those customers are not burdened with FOAK technology cost and risk. This commercial structure is in the final stages of development and the details are confidential at this time.

The Natrium advanced nuclear demonstration project has been named Kemmerer Power Station Unit 1 (KU1) which is planned to be built near the Naughton Power Plant. KU1 is currently in the design and licensing phase. TerraPower submitted the Construction Permit Application to the US Nuclear Regulatory Commission (US NRC) in March 2024. The US NRC has published their review schedule and anticipates the Preliminary Safety Analysis Report and Environmental Report to be approved by August 2026, and the Construction Permit Application to be approved by December 2026. This approval will allow the beginning of construction of the Nuclear Island. An Operating License is also required. TerraPower anticipates the Operating License Application to be submitted in September 2027 and achieving commercial operations the fall of 2031.

On June 10, 2024, TerraPower broke ground for the Natrium reactor demonstration project with construction of the sodium test and fill facility commencing first. On January 14, 2025, the State of Wyoming Industrial Siting Council (ISC) approved TerraPower's permit for construction and operational activities on the Natrium plant that are not under jurisdiction of the US NRC. This approval allows for the construction of non-nuclear facilities, including the energy island portion of the Natrium plant that houses the molten salt energy storage tanks and turbines.

Resource Options and Attributes

Table 7.2 through Table 7.11 report characteristics, attributes and costs for resource options considered in the 2025 IRP. Unlike previous IRP's the supply-side resource table does not list multiple versions of the same technology for various altitudes. Instead, the location adjustments from Appendix A and B of the 2024 EIA[20] report are applied in PLEXOS. Total resource cost attributes for supply-side resource options are based on estimates of the first-year, real-levelized

[20] https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf

costs for resources, stated in June 2024 dollars.[21,22] Table 7.1 provides a listing of these ten tables for convenience.

Table 7.1 – Supply-Side Resource Option Tables

	Characteristics and Costs	**Operating Characteristics and Environmental Data**
Thermal	Table 7.2	Table 7.4
Non-Thermal and Storage	Table 7.3	Table 7.5
	Additional Attributes and Fixed O&M	**Variable O&M, Total Cost and Credits**
Thermal	Table 7.6	Table 7.9
Non-Thermal	Table 7.7	Table 7.10
Storage	Table 7.8	Table 7.11

A Glossary of Terms and a Glossary of Acronyms from the supply-side resource table is summarized in Table 7.12 and Table 7.13.

[21] Supply-side resource attributes were discussed throughout the 2025 public input meeting series and generated stakeholder feedback forms inquiries. 2028 was determined to be the appropriate earliest commercial online year for most proxy resource options. However, PacifiCorp does not preclude the possibility of achieving specific (non-proxy) projects on an earlier timeline outside of the IRP.
See Appendix M, stakeholder feedback form #7 (Renewable Northwest).
See Appendix M, stakeholder feedback form #36 (Sierra Club).
[22] The supply-side resource table was made publicly available during the 2025 IRP public input meeting series and discussed extensively as it developed. https://www.pacificorp.com/energy/integrated-resource-plan/support.html

Table 7.2 – 2025 Thermal Supply-Side Resources, Characteristics and Costs (2024$)

		Characteristics						Costs						
Fuel	Resource Description	Elevation (AFSL)	Net Capacity (MW)	Resource Availability Year	Total Implementation Time (yrs)	Commercial Operation Year	Asset Life (yrs)	Base Capital ($/kW)	Var O&M ($/MWh)	Fraction Var O&M Capitalized	Fraction Var O&M Adjusted by Capacity Changes	Fixed O&M ($/kW-yr)	Fraction Fixed O&M Capitalized	Demolition Cost ($/kW)
Biofuel	Internal Combustion Engine, renewable biofuel, with SCR & 24-hour fuel tank	0	20	2025	2.5	2027	30	$2,131	$6.93	74%	91%	$42.82	3%	$14.59
Natural Gas	SCCT Aero, with SCR	0	50	2025	3.5	2028	40	$2,613	$7.40	87%	98%	$12.42	3%	$32.46
Natural Gas	SCCT Aero x4, with SCR	0	211	2025	3.5	2028	40	$1,789	$5.92	87%	98%	$9.93	3%	$32.46
Natural Gas	SCCT Frame "F" x1, with SCR	0	233	2025	5.0	2030	40	$1,387	$7.75	100%	99%	$27.92	3%	$12.13
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR	0	649	2025	5.0	2030	40	$1,839	$2.70	0%	100%	$42.44	0%	$12.08
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR	0	1,227	2025	5.0	2030	40	$1,553	$2.28	0%	100%	$35.18	0%	$11.89
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 1x1	0	565	2025	5.0	2030	+40	$3,429	$5.32	0%	100%	$77.07	0%	$65.28
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 2x1	0	1085	2025	5.0	2030	+40	$2,846	$4.83	0%	100%	$62.99	0%	$65.08
Natural Gas	Internal Combustion Engine, renewable biofuel, with SCR & 24-hour fuel tank + Δ for CT Brownfield construction	0	20	2025	2.5	2027	30	$1,918	$6.24	74%	91%	$42.82	3%	$14.59
Natural Gas	SCCT Aero, with SCR + Δ for CT Brownfield construction	0	50	2025	3.5	2028	40	$2,352	$6.66	87%	98%	$12.42	3%	$32.46
Natural Gas	SCCT Aero x4, with SCR + Δ for CT Brownfield construction	0	211	2025	3.5	2028	40	$1,610	$5.33	87%	98%	$9.93	3%	$32.46
Natural Gas	SCCT Frame "F" x1, with SCR + Δ for CT Brownfield construction	0	233	2025	5.0	2030	40	$1,248	$6.98	100%	99%	$27.92	3%	$12.13
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR + Δ for CT Brownfield construction	0	649	2025	5.0	2030	40	$1,655	$2.43	0%	100%	$42.44	0%	$12.08
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR + Δ for CT Brownfield construction	0	1,227	2025	5.0	2030	40	$1,398	$2.05	0%	100%	$35.18	0%	$11.89
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 1x1 + Δ for CT Brownfield construction	0	565	2025	5.0	2030	40	$3,086	$4.78	0%	100%	$77.07	0%	$65.28
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 2x1 + Δ for CT Brownfield construction	0	1,085	2025	5.0	2030	40	$2,561	$4.34	0%	100%	$62.99	0%	$65.08
Hydrogen	SCCT Frame "F" x1, with SCR + Δ for 100%Hydrogen burning capability	0	233	2025	5.0	2030	40	$1,595	$8.91	100%	99%	$27.92	3%	$13.95
Hydrogen	CCCT Dry "H", 1X1, DF, with SCR + Δ for 100%Hydrogen burning capability	0	649	2025	5.0	2030	40	$2,115	$3.11	0%	100%	$42.44	0%	$13.89
Hydrogen	CCCT Dry "H", 2X1, DF, with SCR + Δ for 100%Hydrogen burning capability	0	1,227	2025	5.0	2030	40	$1,786	$2.62	0%	100%	$35.18	0%	$13.67
Hydrogen	SCCT Frame "F" x1, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	0	233	2025	5.0	2030	40	$2,586	$8.18	100%	99%	$35.12	3%	$27.13
Hydrogen	CCCT Dry "H", 1X1, DF, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	0	649	2025	5.0	2030	40	$3,038	$3.13	0%	100%	$49.64	0%	$27.08
Hydrogen	CCCT Dry "H", 2X1, DF, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	0	1,227	2025	5.0	2030	40	$2,752	$2.70	0%	100%	$42.38	0%	$26.89
Hydrogen	SCCT Frame "F" x1, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	0	233	2025	5.0	2030	40	$2,098	$8.32	100%	99%	$40.78	3%	$27.13
Hydrogen	CCCT Dry "H", 1X1, DF, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	0	649	2025	5.0	2030	40	$2,550	$3.27	0%	100%	$55.30	0%	$27.08
Hydrogen	CCCT Dry "H", 2X1, DF, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	0	1,227	2025	5.0	2030	40	$2,264	$2.85	0%	100%	$48.04	0%	$26.89
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 1x1	0	649	2025	5.0	2030	+40	$1,832	$2.68	0%	100%	$41.33	0%	$12.08
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 2x1	0	1227	2025	5.0	2030	+40	$1,518	$2.23	0%	100%	$34.07	0%	$11.89
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 1x1 with 95% CCS	0	565	2025	5.0	2030	+40	$3,261	$5.03	0%	100%	$72.60	0%	$65.28
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 2x1 with 95% CCS	0	1085	2025	5.0	2030	+40	$2,637	$4.49	0%	100%	$57.74	0%	$65.08
Hydrogen	Electrolyzer, Proton Exchange Membrane (PEM), 50,000 kg/day	0	-119	2025	5.0	2030	40	$561	$23.91	+0%	0.00	$10.28	100%	$32.46
Coal	CCS Dave Johnston 4 (costs on post retrofit basis)	5,541	-85	2027	5.0	2032	30	$3,501	$11.40	0%	0%	$277.68	0%	$53.20
Coal	CCS Hunter 1-3 (costs on post retrofit basis)	6,429	-297	2027	5.0	2032	30	$2,951	$9.73	0%	0%	$235.36	0%	$53.20
Coal	CCS Huntington 1&2 (costs on post retrofit basis)	6,933	-233	2027	5.0	2032	30	$2,951	$9.63	0%	0%	$242.12	0%	$53.20
Coal	CCS Jim Bridger 3&4 (costs on post retrofit basis)	7,513	-174	2025	5.0	2030	30	$2,598	$10.57	0%	0%	$254.91	0%	$53.20
Coal	CCS Wyodak (costs on post retrofit basis)	4,448	-69	2027	5.0	2032	30	$3,504	$11.69	0%	0%	$309.51	0%	$53.20
Nuclear	Small Modular Reactor or Advanced Reactor, Moderate Technology Case	N/A	600	2030	5.0	2035	60	$9,662	$9.74	0%	0%	$97.42	0%	$17.00
Nuclear	Small Modular Reactor or Advanced Reactor, Advanced Technology Case	N/A	600	2030	4.0	2034	60	$6,368	$8.74	0%	0%	$84.53	0%	$12.00
Nuclear	Small Modular Reactor or Advanced Reactor, Moderate Technology Case + Δ for nuclear integrated thermal storage	N/A	750	2030	5.0	2035	60	$10,628	$10.72	0%	0%	$107.16	0%	$17.00
Nuclear	Small Modular Reactor or Advanced Reactor, Advanced Technology Case + Δ for nuclear integrated thermal storage	N/A	750	2030	4.0	2034	60	$7,005	$9.61	0%	0%	$92.98	0%	$12.00
Nuclear	Large Light Water Reactor, Moderate Technology Case	N/A	2,000	2030	7.0	2037	60	$7,563	$9.38	0%	0%	$125.36	0%	$10.00
Nuclear	Large Light Water Reactor, Advanced Technology Case	N/A	2,000	2030	5.0	2035	60	$6,265	$7.88	0%	0%	$90.26	0%	$9.00
Geothermal	Near Field Enhanhanced Geothermal System (NF-EGS) Binary	N/A	707	2025	3.0	2028	30	$7,593	included in FOM	0%	0%	$194.00	6%	$125.09
Geothermal	Near Field Enhanhanced Geothermal System (NF-EGS) Binary + Δ Advanced Geothermal Technology Case	N/A	707	2025	3.0	2028	30	$5,949	included in FOM	0%	0%	$173.90	6%	$125.09

Table 7.3 – 2025 Non-Thermal Supply-Side Resources, Characteristics and Costs (2024$)[23]

		Characteristics						Costs						
Fuel	Resource Description	Elevation (AFSL)	Net Capacity (MW)	Resource Availability Year	Total Implementation Time (yrs)	Commercial Operation Year	Asset Life (yrs)	Base Capital ($/kW)	Var O&M ($/MWh)	Fraction Var O&M Capitalized	Fraction Var O&M Adjusted by Capacity Changes	Fixed O&M ($/kW-yr)	Fraction Fixed O&M Capitalized	Demolition Cost ($/kW)
Storage[1]	Li-Ion, 4-hour, 20 MW	N/A	20	2025	1.0	2026	20	$1,748	Included in FOM	0%	0%	$45.05	0%	$29.94
Storage[1]	Li-Ion, 4-hour, 200 MW	N/A	200	2025	2.0	2027	20	$1,498	Included in FOM	0%	0%	$38.77	0%	$25.66
Storage[1]	Li-Ion, 4-hour, 200 MW + Δ Double Duration, Li-Ion, 4-hour, 200MW	N/A	200	2025	2.0	2027	20	$2,557	Included in FOM	0%	0%	$69.78	0%	$46.19
Storage[1]	Li-Ion, 4-hour, 1000 MW	N/A	1,000	2025	3.0	2028	20	$1,459	Included in FOM	0%	0%	$36.92	0%	$25.66
Storage	Gravity Battery, 4-hour, 1000 MW	N/A	1,000	2025	3.0	2028	50	$2,021	Included in FOM	0%	0%	$50.51	0%	$0.19
Storage	Gravity Battery, 4-hour, 1000 MW + Δ Double Duration, Gravity, 4-hour, 1000MW	N/A	1,000	2025	3.0	2028	50	$3,006	Included in FOM	0%	0%	$90.92	0%	$0.35
Storage	Adiabatic CAES, 500 MW, 4000 MWh	N/A	500	2025	3.0	2028	50	$3,754	$2.60	50%	0%	$19.20	42%	$49.31
Storage	100-hour Iron Air	N/A	200	2028	2.0	2030	20	$2,730	Included in FOM	0%	0%	$21.04	19%	$171.06
Storage	Pumped Hydro, Two New Reservoirs, 4-hour	N/A	400	2025	5.0	2030	100	$2,984	$0.58	0%	0%	$20.20	45%	$149.21
Storage	Pumped Hydro, Two New Reservoirs, 10-hour	N/A	400	2025	5.0	2030	100	$4,159	$0.58	0%	0%	$20.20	45%	$207.95
Storage	Pumped Hydro, One New Reservoir, 4-hour	N/A	400	2025	5.0	2030	100	$2,883	$0.58	0%	0%	$20.20	45%	$144.16
Storage	Pumped Hydro, One New Reservoir, 10-hour	N/A	400	2025	5.0	2030	100	$3,537	$0.58	0%	0%	$20.20	45%	$176.87
Storage	Pumped Thermal Energy Storage, 10-hour	N/A	100	2026	5.0	2031	60	$6,174	$0.70	0%	0%	$2.00	0%	$60.00
Storage	Pumped Thermal Energy Storage, 24-hour	N/A	50	2026	5.0	2031	60	$11,525	$0.70	0%	0%	$1.00	0%	$60.00
Solar	PV, 20 MW, Class 1-10	by location	20	2025	3.0	2028	25	$1,965	included in FOM	0%	0%	$18.16	12%	$39.29
Solar	PV, 200 MW, Class 1-10	by location	200	2025	3.0	2028	25	$1,217	included in FOM	0%	0%	$20.52	12%	$24.33
Solar	PV, 20 MW, Class 1-10 + Δ Advanced Solar Technology Case	by location	20	2025	3.0	2028	25	$1,832	included in FOM	0%	0%	$17.24	12%	$37.33
Solar	PV, 200 MW, Class 1-10 + Δ Advanced Solar Technology Case	by location	200	2025	3.0	2028	25	$1,135	included in FOM	0%	0%	$19.47	12%	$23.11
Wind	Wind Class 1-10, 20 MW	by location	20	2025	3.0	2028	30	$2,555	included in FOM	0%	0%	$38.79	35%	$63.57
Wind	Wind Class 1-6, 200 MW	by location	200	2025	5.0	2030	30	$1,421	included in FOM	0%	0%	$31.65	35%	$63.57
Wind	Wind Class 7, 200 MW	by location	200	2025	5.0	2030	30	$1,492	included in FOM	0%	0%	$31.65	35%	$63.57
Wind	Offshore, Wind Class 12	0	200	2027	5.0	2032	30	$8,341	included in FOM	0%	0%	$69.26	35%	$169.16
Wind	Wind Class 1-10, 20 MW + Δ Advanced Onshore Wind Technology Case	by location	20	2025	3	2028	30	$2,434	included in FOM	0%	0%	$34.87	35%	$60.58
Wind	Wind Class 1-6, 200 MW + Δ Advanced Onshore Wind Technology Case	by location	200	2025	5	2030	30	$1,354	included in FOM	0%	0%	$28.45	35%	$60.58
Wind	Wind Class 7, 200 MW + Δ Advanced Onshore Wind Technology Case	by location	200	2025	5	2030	30	$1,422	included in FOM	0%	0%	$28.45	35%	$60.58
Wind	Offshore, Wind Class 12 + Δ Advanced Offshore Wind Technology Case	0	200	2027	5	2032	30	$6,011	included in FOM	0%	0%	$63.21	35%	$121.92

[1] Assumed co-located

[23] See Appendix M, stakeholder feedback form #49 (Utah Association of Energy Users)

Table 7.4 – 2025 Thermal Supply-Side Resources, Operating Characteristics and Environmental Data (2024$)

		Operating Characteristics				Environmental Data				
Fuel	Resource Description	Average Full Load Heat Rate (HHV Btu/KWh)	Efficiency	EFOR (%)	POR (%)	Water Consumed (Gal/MWh)	SO2 (lbs/MMBtu)	NOx (lbs/MMBtu)	Hg (lbs/TBTu)	CO2 (lbs/MMBtu)
Biofuel	Internal Combustion Engine, renewable biofuel, with SCR & 24-hour fuel tank	8,295	41.13%	2.50%	5.0%	27.1	0.00152	0.02000	0.000	117
Natural Gas	SCCT Aero, with SCR	9,447	36.12%	2.90%	3.9%	27.0	0.00150	0.00750	0.000	117
Natural Gas	SCCT Aero x4, with SCR	9,447	36.12%	2.90%	3.9%	27.0	0.00150	0.00750	0.000	117
Natural Gas	SCCT Frame "F" x1, with SCR	9,717	35.12%	2.70%	3.9%	28.4	0.00150	0.00750	0.000	117
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR	6,040	56.49%	2.50%	3.8%	210.0	0.00150	0.00750	0.000	117
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR	6,122	55.74%	2.50%	3.8%	210.0	0.00150	0.00750	0.000	117
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 1x1	6,743	53.17%	2.50%	3.8%	323.4	0.00150	0.00563	0.000	6
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 2x1	6,843	52.46%	2.50%	3.8%	323.4	0.00150	0.00563	0.000	6
Natural Gas	Internal Combustion Engine, renewable biofuel, with SCR & 24-hour fuel tank + Δ for CT Brownfield construction	8,295	41.13%	2.50%	5.0%	27.1	0.00152	0.02131	0.000	117
Natural Gas	SCCT Aero, with SCR + Δ for CT Brownfield construction	9,447	36.12%	2.90%	3.9%	27.0	0.00150	0.00799	0.000	117
Natural Gas	SCCT Aero x4, with SCR + Δ for CT Brownfield construction	9,447	36.12%	2.90%	3.9%	27.0	0.00150	0.00799	0.000	117
Natural Gas	SCCT Frame "F" x1, with SCR + Δ for CT Brownfield construction	9,717	35.12%	2.70%	3.9%	28.4	0.00150	0.00799	0.000	117
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR + Δ for CT Brownfield construction	6,040	56.49%	2.50%	3.8%	210.0	0.00150	0.00799	0.000	117
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR + Δ for CT Brownfield construction	6,122	55.74%	2.50%	3.8%	210.0	0.00150	0.00799	0.000	117
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 1x1 + Δ for CT Brownfield construction	6,743	53.17%	2.50%	3.8%	323.4	0.00150	0.00599	0.000	6
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 2x1 + Δ for CT Brownfield construction	6,843	52.46%	2.50%	3.8%	323.4	0.00150	0.00599	0.000	6
Hydrogen	SCCT Frame "F" x1, with SCR + Δ for 100%Hydrogen burning capability	9,717	35.12%	2.70%	3.90%	28.4	0.00000	0.00750	0.000	0
Hydrogen	CCCT Dry "H", 1X1, DF, with SCR + Δ for 100%Hydrogen burning capability	6,040	56.49%	2.50%	3.80%	210.0	0.00000	0.00750	0.000	0
Hydrogen	CCCT Dry "H", 2X1, DF, with SCR + Δ for 100%Hydrogen burning capability	6,122	55.74%	2.50%	3.80%	210.0	0.00000	0.00750	0.000	0
Hydrogen	SCCT Frame "F" x1, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	9,717	35.12%	2.75%	3.90%	28.4	0.00196	0.00946	0.002	0
Hydrogen	CCCT Dry "H", 1X1, DF, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	6,040	56.49%	2.55%	3.80%	210.0	0.00196	0.00946	0.002	0
Hydrogen	CCCT Dry "H", 2X1, DF, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	6,122	55.74%	2.55%	3.80%	210.0	0.00196	0.00946	0.002	0
Hydrogen	SCCT Frame "F" x1, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	9,717	35.12%	2.75%	3.90%	28.4	0.00196	0.00946	0.002	0
Hydrogen	CCCT Dry "H", 1X1, DF, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	6,040	56.49%	2.55%	3.80%	210.0	0.00196	0.00946	0.002	0
Hydrogen	CCCT Dry "H", 2X1, DF, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	6,122	55.74%	2.55%	3.80%	210.0	0.00196	0.00946	0.002	0
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 1x1	6,040	56.49%	2.50%	3.8%	210.0	0.00150	0.00750	0.000	117
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 2x1	6,122	55.74%	2.50%	3.8%	210.0	0.00150	0.00750	0.000	117
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 1x1 with 95% CCS	6,743	53.17%	2.50%	3.8%	323.4	0.00150	0.00563	0.000	6
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 2x1 with 95% CCS	6,843	52.46%	2.50%	3.8%	323.4	0.00150	0.00563	0.000	6
Hydrogen	Electrolyzer, Proton Exchange Membrane (PEM), 50,000 kg/day	N/A	79.13%	1.50%	1.5%	45.7	0.00000	0.00000	0.000	0
Coal	CCS Dave Johnston 4 (costs on post retrofit basis)	14,795	23.06%	7.50%	7.50%	186.0	10.00000	0.07100	0.304	10
Coal	CCS Hunter 1-3 (costs on post retrofit basis)	14,011	24.35%	7.50%	7.50%	186.0	10.00000	0.07100	0.304	10
Coal	CCS Huntington 1&2 (costs on post retrofit basis)	13,662	24.98%	7.50%	7.50%	186.0	10.00000	0.07100	0.304	10
Coal	CCS Jim Bridger 3&4 (costs on post retrofit basis)	14,483	23.56%	7.50%	7.50%	186.0	10.00000	0.07100	0.304	10
Coal	CCS Wyodak (costs on post retrofit basis)	16,653	20.49%	7.50%	7.50%	186.0	10.00000	0.07100	0.304	10
Nuclear	Small Modular Reactor or Advanced Reactor, Moderate Technology Case	9,180	37%	2%	5%	720.0	0.00000	0.00000	0.000	0
Nuclear	Small Modular Reactor or Advanced Reactor, Advanced Technology Case	9,180	37%	2%	5%	720.0	0.00000	0.00000	0.000	0
Nuclear	Small Modular Reactor or Advanced Reactor, Moderate Technology Case + Δ for nuclear integrated thermal storage	12,626	37.17%	2.00%	5.0%	720.0	0.00000	0.00000	0.000	0
Nuclear	Small Modular Reactor or Advanced Reactor, Advanced Technology Case + Δ for nuclear integrated thermal storage	12,626	37.17%	2.00%	5.0%	720.0	0.00000	0.00000	0.000	0
Nuclear	Large Light Water Reactor, Moderate Technology Case	10,497	33%	2%	5%	720.0	0.00000	0.00000	0.000	0
Nuclear	Large Light Water Reactor, Advanced Technology Case	10,497	33%	2%	5%	720.0	0.00000	0.00000	0.000	0
Geothermal	Near Field Enhanhanced Geothermal System (NF-EGS) Binary	N/A	N/A	10%	10%	510.0	n/a	n/a	n/a	n/a
Geothermal	Near Field Enhanhanced Geothermal System (NF-EGS) Binary + Δ Advanced Geothermal Technology Case	N/A	N/A	10.00%	10.00%	510.0	n/a	n/a	n/a	n/a

Table 7.5 – 2025 Non-Thermal Supply-Side Resources, Operating Characteristics and Environmental Data (2024$)

		Operating Characteristics				Environmental Data				
Fuel	Resource Description	Average Full Load Heat Rate (HHV Btu/KWh)	Efficiency	EFOR (%)	POR (%)	Water Consumed (Gal/MWh)	SO2 (lbs/MMBtu)	NOx (lbs/MMBtu)	Hg (lbs/TBTu)	CO2 (lbs/MMBtu)
Storage[1]	Li-Ion, 4-hour, 20 MW	n/a	85%	1.0%	included in CF	n/a	0.00000	0.00000	0.000	0
Storage[1]	Li-Ion, 4-hour, 200 MW	n/a	85%	1%	included in CF	n/a	0.00000	0.00000	0.000	0
Storage[1]	Li-Ion, 4-hour, 200 MW + Δ Double Duration, Li-Ion, 4-hour, 200MW	n/a	85.00%	1.00%	included in CF	n/a	0.00000	0.00000	0.000	0
Storage[1]	Li-Ion, 4-hour, 1000 MW	n/a	85%	1.0%	included in CF	n/a	0.00000	0.00000	0.000	0
Storage	Gravity Battery, 4-hour, 1000 MW	n/a	83%	1.0%	included in CF	n/a	0.00000	0.00000	0.000	0
Storage	Gravity Battery, 4-hour, 1000 MW + Δ Double Duration, Gravity, 4-hour, 1000MW	n/a	83.00%	1.00%	included in CF	n/a	0.00000	0.00000	0.000	0
Storage	Adiabatic CAES, 500 MW, 4000 MWh	n/a	63%	1.1%	1.1%	n/a	0.00000	0.00000	0.000	0
Storage	100-hour Iron Air	n/a	43%	1.0%	included in CF	0.0	0.00000	0.00000	0.000	0
Storage	Pumped Hydro, Two New Reservoirs, 4-hour	n/a	80%	2.0%	4.0%	n/a	0.00000	0.00000	0.000	0
Storage	Pumped Hydro, Two New Reservoirs, 10-hour	n/a	80%	2.0%	4.0%	n/a	0.00000	0.00000	0.000	0
Storage	Pumped Hydro, One New Reservoir, 4-hour	n/a	80%	2.0%	4.0%	n/a	0.00000	0.00000	0.000	0
Storage	Pumped Hydro, One New Reservoir, 10-hour	n/a	80%	2.0%	4.0%	n/a	0.00000	0.00000	0.000	0
Storage	Pumped Thermal Energy Storage, 10-hour	n/a	55%	2.0%	3.0%	n/a	0.00000	0.00000	0.000	0
Storage	Pumped Thermal Energy Storage, 24-hour	n/a	55%	2.0%	3.0%	n/a	0.00000	0.00000	0.000	0
Solar	PV, 20 MW, Class 1-10	N/A	by location	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Solar	PV, 200 MW, Class 1-10	N/A	by location	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Solar	PV, 20 MW, Class 1-10 + Δ Advanced Solar Technology Case	N/A	by location	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Solar	PV, 200 MW, Class 1-10 + Δ Advanced Solar Technology Case	N/A	by location	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind	Wind Class 1-10, 20 MW	N/A	by location	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind	Wind Class 1-6, 200 MW	N/A	by location	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind	Wind Class 7, 200 MW	N/A	by location	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind	Offshore, Wind Class 12	N/A	max CF: 47%	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind	Wind Class 1-10, 20 MW + Δ Advanced Onshore Wind Technology Case	N/A	by location	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind	Wind Class 1-6, 200 MW + Δ Advanced Onshore Wind Technology Case	N/A	by location	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind	Wind Class 7, 200 MW + Δ Advanced Onshore Wind Technology Case	N/A	by location	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind	Offshore, Wind Class 12 + Δ Advanced Offshore Wind Technology Case	N/A	max CF: 47%	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a

[1] Assumed co-located

Table 7.6 – 2025 IRP Thermal Supply-Side Resources, Additional Attributes and Fixed O&M (2024$)

	Additional Attributes							Fixed O&M						
Resource Description	Modeled IRP	Elevation (AFSL)	Total Capital Cost	Demolition Cost	Payment Factor (real levelized)	Annual Payment ($/kW-Yr)	Capacity Factor	O&M ($/kW-Yr)	Capitalized Premium	O&M Capitalized ($/kW-Yr)	Gas Transport ($/kW-Yr)	Total Fixed O&M ($/kW-Yr)	Total Fixed Cost ($/kW-Yr)	Total Fixed Cost Converted ($/MWh)
Internal Combustion Engine, renewable biofuel, with SCR & 24-hour fuel tank	Yes	0	$ 2,130.94	$ 14.59	6.890%	$147.83	92.50%	$42.82	2.62%	$1.12	$0.00	$43.94	$191.77	$23.67
SCCT Aero, with SCR	No	0	$ 2,612.80	$ 32.46	6.101%	$161.39	33.00%	$12.42	2.62%	$0.32	$0.00	$12.74	$174.13	$60.24
SCCT Aero x4, with SCR	No	0	$ 1,789.35	$ 32.46	6.104%	$111.20	33.00%	$9.93	2.62%	$0.26	$0.00	$10.19	$121.40	$41.99
SCCT Frame "F" x1, with SCR	Yes	0	$ 1,386.92	$ 12.13	6.100%	$85.34	33.00%	$27.92	2.62%	$0.73	$0.00	$28.65	$114.00	$39.43
Goshen	Yes	2,814	$ 1,400.79	$ 12.13	6.100%	$86.19	33.00%	$27.92	2.62%	$0.73	$96.20	$124.85	$211.04	$73.00
Wasatch Front	Yes	4,225	$ 1,373.05	$ 12.13	6.100%	$84.50	33.00%	$27.92	2.62%	$0.73	$14.72	$43.38	$127.87	$44.23
Wyoming East	Yes	6,130	$ 1,373.05	$ 12.13	6.100%	$84.50	33.00%	$27.92	2.62%	$0.73	$25.80	$54.45	$138.95	$48.07
CCCT Dry "H", 1X1, DF, with SCR	Yes	0	$ 1,839.00	$ 12.08	6.233%	$115.38	78.00%	$42.44	2.62%	$1.11	$0.00	$43.55	$158.93	$23.26
Goshen	Yes	2,814	$ 1,857.39	$ 12.08	6.233%	$116.52	78.00%	$42.44	2.62%	$1.11	$60.34	$103.89	$220.41	$32.26
Wasatch Front	Yes	4,225	$ 1,820.61	$ 12.08	6.233%	$114.23	78.00%	$42.44	2.62%	$1.11	$9.25	$52.81	$167.04	$24.45
Wyoming East	Yes	6,130	$ 1,820.61	$ 12.08	6.233%	$114.23	78.00%	$42.44	2.62%	$1.11	$16.33	$59.88	$174.11	$25.48
CCCT Dry "H", 2X1, DF, with SCR	Yes	0	$ 1,553.26	$ 11.89	6.234%	$97.57	78.00%	$35.18	2.62%	$0.92	$0.00	$36.10	$133.67	$19.56
Goshen	Yes	2,814	$ 1,568.79	$ 11.89	6.234%	$98.54	78.00%	$35.18	2.62%	$0.92	$61.16	$97.26	$195.80	$28.66
Wasatch Front	Yes	4,225	$ 1,537.73	$ 11.89	6.234%	$96.60	78.00%	$35.18	2.62%	$0.92	$9.38	$45.48	$142.08	$20.79
Wyoming East	Yes	6,130	$ 1,537.73	$ 11.89	6.234%	$96.60	78.00%	$35.18	2.62%	$0.92	$16.55	$52.65	$149.26	$21.84
CCCT Dry "H", 1X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 1x1	No	0	$ 3,429.38	$ 65.28	6.239%	$218.03	78.00%	$77.07	5.54%	$4.27	$0.00	$81.34	$299.37	$43.81
CCCT Dry "H", 2X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 2x1	No	0	$ 2,846.02	$ 65.08	6.241%	$181.68	78.00%	$62.99	5.54%	$3.49	$0.00	$66.48	$248.16	$36.32
Internal Combustion Engine, renewable biofuel, with SCR + Δ for CT Brownfield construction	No	0	$ 1,917.85	$ 14.59	6.891%	$133.16	33.00%	$42.82	2.62%	$1.12	$0.00	$43.94	$177.10	$61.26
SCCT Aero, with SCR + Δ for CT Brownfield construction	No	0	$ 2,351.52	$ 32.46	6.102%	$145.47	33.00%	$12.42	2.62%	$0.32	$0.00	$12.74	$158.21	$54.73
SCCT Aero x4, with SCR + Δ for CT Brownfield construction	No	0	$ 1,610.42	$ 32.46	6.105%	$100.30	33.00%	$9.93	2.62%	$0.26	$0.00	$10.19	$110.49	$38.22
SCCT Frame "F" x1, with SCR + Δ for CT Brownfield construction	Yes	0	$ 1,248.23	$ 12.13	6.100%	$76.88	33.00%	$27.92	2.62%	$0.73	$0.00	$28.65	$105.53	$36.51
Goshen-Brownfield	No	2,814	$ 1,260.71	$ 12.13	6.100%	$77.64	33.00%	$27.92	2.62%	$0.73	$96.20	$124.85	$202.50	$70.05
Wasatch Front-Brownfield	Yes	4,225	$ 1,235.75	$ 12.13	6.100%	$76.12	33.00%	$27.92	2.62%	$0.73	$14.72	$43.38	$119.50	$41.34
Wyoming East-Brownfield	Yes	6,130	$ 1,235.75	$ 12.13	6.100%	$76.12	33.00%	$27.92	2.62%	$0.73	$25.80	$54.45	$130.57	$45.17
CCCT Dry "H", 1X1, DF, with SCR + Δ for CT Brownfield construction	Yes	0	$ 1,655.10	$ 12.08	6.234%	$103.93	78.00%	$42.44	2.62%	$1.11	$0.00	$43.55	$147.48	$21.58
Goshen-Brownfield	No	2,814	$ 1,671.65	$ 12.08	6.234%	$104.96	78.00%	$42.44	2.62%	$1.11	$60.34	$103.89	$208.85	$30.57
Wasatch Front-Brownfield	Yes	4,225	$ 1,638.55	$ 12.08	6.234%	$102.90	78.00%	$42.44	2.62%	$1.11	$9.25	$52.81	$155.71	$22.79
Wyoming East-Brownfield	Yes	6,130	$ 1,638.55	$ 12.08	6.234%	$102.90	78.00%	$42.44	2.62%	$1.11	$16.33	$59.88	$162.78	$23.82
CCCT Dry "H", 2X1, DF, with SCR + Δ for CT Brownfield construction	Yes	0	$ 1,397.93	$ 11.89	6.234%	$87.89	78.00%	$35.18	2.62%	$0.92	$0.00	$36.10	$123.99	$18.15
Goshen-Brownfield	No	2,814	$ 1,411.91	$ 11.89	6.234%	$88.76	78.00%	$35.18	2.62%	$0.92	$61.16	$97.26	$186.02	$27.22
Wasatch Front-Brownfield	Yes	4,225	$ 1,383.95	$ 11.89	6.234%	$87.02	78.00%	$35.18	2.62%	$0.92	$9.38	$45.48	$132.50	$19.39
Wyoming East-Brownfield	Yes	6,130	$ 1,383.95	$ 11.89	6.234%	$87.02	78.00%	$35.18	2.62%	$0.92	$16.55	$52.65	$139.67	$20.44
CCCT Dry "H", 1X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 1x1 + Δ for CT Brownfield construction	No	0	$ 3,086.44	$ 65.28	6.240%	$196.67	78.00%	$77.07	5.54%	$4.27	$0.00	$81.34	$278.00	$40.69
CCCT Dry "H", 2X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 2x1 + Δ for CT Brownfield construction	No	0	$ 2,561.42	$ 65.08	6.242%	$163.95	78.00%	$62.99	5.54%	$3.49	$0.00	$66.48	$230.43	$33.72
SCCT Frame "F" x1, with SCR + Δ for 100%Hydrogen burning capability	No	0	$ 1,594.96	$ 13.95	5.605%	$90.18	33.00%	$27.92	2.62%	$0.73	$0.00	$28.65	$118.83	$41.11
CCCT Dry "H", 1X1, DF, with SCR + Δ for 100%Hydrogen burning capability	No	0	$ 2,114.85	$ 13.89	5.604%	$119.29	78.00%	$42.44	2.62%	$1.11	$0.00	$43.55	$162.85	$23.83
CCCT Dry "H", 2X1, DF, with SCR + Δ for 100%Hydrogen burning capability	No	0	$ 1,786.25	$ 13.67	5.604%	$100.87	78.00%	$35.18	2.62%	$0.92	$0.00	$36.10	$136.97	$20.05
SCCT Frame "F" x1, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	No	0	$ 2,585.93	$ 27.13	9.271%	$242.26	33.00%	$35.12	2.62%	$0.92	$0.00	$36.04	$278.30	$96.27
CCCT Dry "H", 1X1, DF, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	No	0	$ 3,038.01	$ 27.08	9.254%	$283.64	78.00%	$49.64	2.62%	$1.30	$0.00	$50.94	$334.59	$48.97
CCCT Dry "H", 2X1, DF, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	No	0	$ 2,752.27	$ 26.89	9.263%	$257.43	78.00%	$42.38	2.62%	$1.11	$0.00	$43.49	$300.93	$44.04
SCCT Frame "F" x1, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	No	0	$ 2,097.84	$ 27.13	9.255%	$196.67	33.00%	$40.78	2.62%	$1.07	$0.00	$41.85	$238.51	$82.51
CCCT Dry "H", 1X1, DF, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	No	0	$ 2,549.91	$ 27.08	9.245%	$238.24	78.00%	$55.30	2.62%	$1.45	$0.00	$56.75	$294.99	$43.17
CCCT Dry "H", 2X1, DF, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	No	0	$ 2,264.18	$ 26.89	9.250%	$211.92	78.00%	$48.04	2.62%	$1.26	$0.00	$49.30	$261.22	$38.23
CCCT Dry "H", 1X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 1x1	No	0	$ 1,831.63	$ 12.08	6.233%	$114.92	78.00%	$41.33	2.62%	$1.08	$0.00	$42.41	$157.33	$23.02
CCCT Dry "H", 2X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 2x1	No	0	$ 1,517.84	$ 11.89	6.234%	$95.36	78.00%	$34.07	2.62%	$0.89	$0.00	$34.96	$130.32	$19.07
CCCT Dry "H", 1X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 1x1, 95% CCS	No	0	$ 3,260.88	$ 65.28	6.233%	$207.32	78.00%	$72.60	5.54%	$4.02	$0.00	$76.62	$283.94	$41.56
CCCT Dry "H", 2X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 2x1, 95% CCS	No	0	$ 2,637.12	$ 65.08	6.234%	$168.46	78.00%	$57.74	5.54%	$3.20	$0.00	$60.94	$229.40	$33.57
Hydrogen peaker with CCCT Dry "H", 2X1, DF and electrolyzer	Yes	0	$ 2,858.50	$ 44.94	4.170%	$121.07	98.00%	$60.95	0.00%	$0.00	$0.00	$60.95	$182.03	$21.20
Electrolyzer, Proton Exchange Membrane (PEM), 50,000 kg/day	No	0	$ 560.99	$ 32.46	4.170%	$24.75	97.00%	$10.28	0.00%	$0.00	$0.00	$10.28	$35.03	$4.12
Δ CCS Dave Johnston 4 (costs on post retrofit basis)	No	5,541	$ 3,500.78	$ 53.20	6.447%	$229.12	85.00%	$277.68	5.54%	$15.38	$0.00	$293.06	$522.19	$70.13
Δ CCS Hunter 1-3 (costs on post retrofit basis)	No	6,429	$ 2,951.20	$ 53.20	6.451%	$193.81	85.00%	$235.36	5.54%	$13.04	$0.00	$248.39	$442.21	$59.39
Δ CCS Huntington 1&2 (costs on post retrofit basis)	No	6,933	$ 2,951.40	$ 53.20	6.451%	$193.83	85.00%	$242.12	5.54%	$13.41	$0.00	$255.53	$449.36	$60.35
Δ CCS Jim Bridger 3&4 (costs on post retrofit basis)	Yes	7,513	$ 2,598.38	$ 53.20	6.454%	$171.13	85.00%	$254.91	5.54%	$14.12	$0.00	$269.03	$440.16	$59.11
Δ CCS Wyodak (costs on post retrofit basis)	No	4,448	$ 3,504.25	$ 53.20	6.447%	$229.35	85.00%	$309.51	5.54%	$17.15	$0.00	$326.65	$556.00	$74.67
Small Modular Reactor or Advanced Reactor, Moderate Technology Case	Yes	N/A	$ 9,662.09	$ 17.00	5.042%	$488.02	93.00%	$97.42	9.42%	$9.18	$0.00	$106.60	$594.62	$72.99
Goshen	Yes	2,814	$ 9,855.33	$ 17.00	5.042%	$497.76	93.00%	$97.42	9.42%	$9.18	$0.00	$106.60	$604.36	$74.18
Wasatch Front	Yes	4,225	$ 9,855.33	$ 17.00	5.042%	$497.76	93.00%	$97.42	9.42%	$9.18	$0.00	$106.60	$604.36	$74.18
Wyoming East	Yes	6,130	$ 9,565.47	$ 17.00	5.042%	$483.15	93.00%	$97.42	9.42%	$9.18	$0.00	$106.60	$589.75	$72.39
Small Modular Reactor or Advanced Reactor, Advanced Technology Case	No	N/A	$ 6,368.23	$ 12.00	5.042%	$321.69	93.00%	$84.53	9.42%	$7.97	$0.00	$92.49	$414.18	$50.84
Small Modular Reactor or Advanced Reactor, Moderate Technology Case + Δ for nuclear integrated thermal storage	No	N/A	$ 10,628.30	$ 17.00	5.042%	$536.74	93.00%	$107.16	9.42%	$10.10	$0.00	$117.26	$654.00	$80.28
Small Modular Reactor or Advanced Reactor, Advanced Technology Case + Δ for nuclear integrated thermal storage	No	N/A	$ 7,005.05	$ 12.00	5.042%	$353.80	93.00%	$92.98	9.42%	$8.76	$0.00	$101.74	$455.54	$55.92
Large Light Water Reactor, Moderate Technology Case	No	N/A	$ 7,562.87	$ 10.00	5.042%	$381.82	93.00%	$125.36	9.42%	$11.81	$0.00	$137.17	$518.99	$63.71
Large Light Water Reactor, Advanced Technology Case	No	N/A	$ 6,265.25	$ 9.00	5.042%	$316.35	93.00%	$90.26	9.42%	$8.51	$0.00	$98.76	$415.11	$50.95
Near Field Enhanhanced Geothermal System (NF-EGS) Binary	Yes	N/A	$ 7,593.06	$ 125.09	6.262%	$483.31	80.00%	$194.00	0.87%	$1.69	$0.00	$195.69	$679.00	$96.89
Southern OR	Yes	497	$ 8,883.88	$ 125.09	6.262%	$564.14	80.00%	$194.00	0.87%	$1.69	$0.00	$195.69	$759.83	$108.42
Wasatch Front	Yes	4,225	$ 7,593.06	$ 125.09	6.262%	$483.31	80.00%	$194.00	0.87%	$1.69	$0.00	$195.69	$679.00	$96.89

* Δ for CCS installation on existing coal units is for CCS costs and operating characterisitics only, not the operation of the existing coal resource.

Table 7.7 – 2025 IRP Non-Thermal Supply-Side Resources, Additional Attributes and Fixed O&M (2024$)

	Additional Attributes							Fixed O&M					
Resource Description	Modeled IRP	Elevation (AFSL)	Total Capital Cost	Demolition Cost	Payment Factor (real levelized)	Annual Payment ($/kW-Yr)	Capacity Factor	O&M ($/kW-Yr)	Capitalized Premium	O&M Capitalized ($/kW-Yr)	Total Fixed O&M ($/kW-Yr)	Total Fixed Cost ($/kW-Yr)	Total Fixed Cost Converted ($/MWh)
PV, 20 MW, Class 1-10	Yes	by location	$ 1,964.64	$ 39.29	6.861%	$137.49	27.33%	$18.16	1.37%	$0.25	$18.41	$155.90	$65.11
Portland North Coast	Yes	19	$ 2,082.51	$ 39.29	6.861%	$145.58	24.49%	$18.16	1.37%	$0.25	$18.41	$163.99	$76.45
Southern OR	Yes	497	$ 2,180.75	$ 39.29	6.861%	$152.32	29.29%	$18.16	1.37%	$0.25	$18.41	$170.73	$66.54
Walla Walla	Yes	2,353	$ 2,003.93	$ 39.29	6.861%	$140.19	25.96%	$18.16	1.37%	$0.25	$18.41	$158.60	$69.74
Goshen	Yes	2,814	$ 1,984.28	$ 39.29	6.861%	$138.84	27.79%	$18.16	1.37%	$0.25	$18.41	$157.25	$64.59
Wasatch Front	Yes	4,225	$ 1,964.64	$ 39.29	6.861%	$137.49	29.00%	$18.16	1.37%	$0.25	$18.41	$155.90	$61.38
Wyoming East	Yes	6,130	$ 1,964.64	$ 39.29	6.861%	$137.49	27.47%	$18.16	1.37%	$0.25	$18.41	$155.90	$64.79
PV, 200 MW, Class 1-10	Yes	by location	$ 1,216.55	$ 24.33	6.861%	$85.14	27.33%	$20.52	1.37%	$0.28	$20.80	$105.93	$44.24
Portland North Coast	Yes	19	$ 1,289.55	$ 24.33	6.861%	$90.15	24.49%	$20.52	1.37%	$0.28	$20.80	$110.94	$51.72
Southern OR	Yes	497	$ 1,350.37	$ 24.33	6.861%	$94.32	29.29%	$20.52	1.37%	$0.28	$20.80	$115.12	$44.87
Walla Walla	Yes	2,353	$ 1,240.88	$ 24.33	6.861%	$86.81	25.96%	$20.52	1.37%	$0.28	$20.80	$107.60	$47.32
Goshen	Yes	2,814	$ 1,228.72	$ 24.33	6.861%	$85.97	27.79%	$20.52	1.37%	$0.28	$20.80	$106.77	$43.86
Wasatch Front	Yes	4,225	$ 1,216.55	$ 24.33	6.861%	$85.14	29.00%	$20.52	1.37%	$0.28	$20.80	$105.93	$41.71
Wyoming East	Yes	6,130	$ 1,216.55	$ 24.33	6.861%	$85.14	27.47%	$20.52	1.37%	$0.28	$20.80	$105.93	$44.02
PV, 20 MW, Class 1-10 + Δ Advanced Solar Technology Case	No	by location	$ 1,832.22	$ 37.33	6.862%	$128.29	27.33%	$17.24	1.37%	$0.24	$17.48	$145.76	$60.88
PV, 200 MW, Class 1-10 + Δ Advanced Solar Technology Case	No	by location	$ 1,134.56	$ 23.11	6.862%	$79.44	27.33%	$19.47	1.37%	$0.27	$19.74	$99.18	$41.42
Wind Class 1-10, 20 MW	Yes	by location	$ 2,554.58	$ 63.57	6.292%	$164.73	29.07%	$38.79	4.39%	$1.70	$40.49	$205.22	$80.60
Portland North Coast	Yes	19	$ 2,835.59	$ 63.57	6.292%	$182.42	24.91%	$38.79	4.39%	$1.70	$40.49	$222.90	$102.14
Southern OR	Yes	497	$ 3,014.41	$ 63.57	6.292%	$193.67	25.18%	$38.79	4.39%	$1.70	$40.49	$234.15	$106.14
Walla Walla	Yes	2,353	$ 2,656.77	$ 63.57	6.292%	$171.16	23.13%	$38.79	4.39%	$1.70	$40.49	$211.65	$104.46
Goshen	Yes	2,814	$ 2,605.68	$ 63.57	6.292%	$167.95	34.26%	$38.79	4.39%	$1.70	$40.49	$208.44	$69.45
Wasatch Front	Yes	4,225	$ 2,580.13	$ 63.57	6.292%	$166.34	33.69%	$38.79	4.39%	$1.70	$40.49	$206.83	$70.08
Wyoming East	Yes	6,130	$ 2,503.49	$ 63.57	6.292%	$161.52	33.22%	$38.79	4.39%	$1.70	$40.49	$202.01	$69.41
Wind Class 1-6, 200 MW	Yes	by location	$ 1,421.10	$ 63.57	6.316%	$93.77	34.37%	$31.65	4.39%	$1.39	$33.04	$126.81	$42.12
Portland North Coast	Yes	19	$ 1,577.43	$ 63.57	6.316%	$103.65	37.62%	$31.65	4.39%	$1.39	$33.04	$136.68	$41.47
Southern OR	Yes	497	$ 1,676.90	$ 63.57	6.316%	$109.93	34.06%	$31.65	4.39%	$1.39	$33.04	$142.97	$47.92
Walla Walla	Yes	2,353	$ 1,477.95	$ 63.57	6.316%	$97.36	32.59%	$31.65	4.39%	$1.39	$33.04	$130.40	$45.68
Goshen	Yes	2,814	$ 1,449.53	$ 63.57	6.316%	$95.57	30.28%	$31.65	4.39%	$1.39	$33.04	$128.61	$48.49
Wasatch Front	Yes	4,225	$ 1,435.32	$ 63.57	6.316%	$94.67	30.42%	$31.65	4.39%	$1.39	$33.04	$127.71	$47.93
Wyoming East	Yes	6,130	$ 1,392.68	$ 63.57	6.316%	$91.98	41.25%	$31.65	4.39%	$1.39	$33.04	$125.02	$34.60
Wind Class 7, 200 MW	No	by location	$ 1,491.78	$ 63.57	6.313%	$98.19	34.37%	$31.65	4.39%	$1.39	$33.04	$131.23	$43.59
Offshore, Wind Class 12	Yes	0	$ 8,340.57	$ 169.16	5.202%	$442.68	31.54%	$69.26	4.39%	$3.04	$72.30	$514.98	$186.38
Southern OR	Yes	497	$ 9,841.87	$ 169.16	5.202%	$520.77	48.94%	$69.26	4.39%	$3.04	$72.30	$593.07	$138.33
Wind Class 1-10, 20 MW + Δ Advanced Onshore Wind Technology Case	No	by location	$ 2,434.26	$ 60.58	6.292%	$156.98	29.07%	$34.87	4.39%	$1.53	$36.40	$193.37	$75.95
Wind Class 1-6, 200 MW + Δ Advanced Onshore Wind Technology Case	No	by location	$ 1,354.17	$ 60.58	6.316%	$89.36	34.37%	$28.45	4.39%	$1.25	$29.70	$119.06	$39.54
Wind Class 7, 200 MW + Δ Advanced Onshore Wind Technology Case	No	by location	$ 1,421.51	$ 60.58	6.313%	$93.56	34.37%	$28.45	4.39%	$1.25	$29.70	$123.27	$40.94
Offshore, Wind Class 12 + Δ Advanced Offshore Wind Technology Case	No	0	$ 6,011.05	$ 121.92	4.841%	$296.90	84.43%	$63.21	4.39%	$2.78	$65.99	$362.89	$49.06

Table 7.8 – 2025 IRP Storage Supply-Side Resources, Additional Attributes and Fixed O&M (2024$)

	Additional Attributes								Fixed O&M					
Resource Description	Modeled IRP	Elevation (AFSL)	Total Capital Cost	Demolition Cost	Payment Factor (real levelized)	Annual Payment ($/kW-Yr)	Capacity Factor	Storage Efficiency	O&M ($/kW-Yr)	Capitalized Premium	O&M Capitalized ($/kW-Yr)	Total Fixed O&M ($/kW-Yr)	Total Fixed Cost ($/kW-Yr)	Total Fixed Cost Converted ($/MWh)
Li-Ion, 4-hour, 20 MW[1]	No	N/A	$ 1,747.61	$ 29.94	5.354%	$95.17	16.67%	85%	$45.05	0.00%	$ -	$45.05	$140.22	$96.04
Li-Ion, 4-hour, 200 MW[1]	Yes	N/A	$ 1,497.89	$ 25.66	5.354%	$81.57	16.67%	85%	$38.77	0.00%	$0.00	$38.77	$120.34	$82.42
Portland North Coast	Yes	19	$ 1,587.77	$ 25.66	5.354%	$86.38	16.67%	85%	$38.77	0.00%	$0.00	$38.77	$125.15	$85.72
Southern OR	Yes	497	$ 1,617.73	$ 25.66	5.354%	$87.99	16.67%	85%	$38.77	0.00%	$0.00	$38.77	$126.75	$86.82
Walla Walla	Yes	2,353	$ 1,542.83	$ 25.66	5.354%	$83.98	16.67%	85%	$38.77	0.00%	$0.00	$38.77	$122.74	$84.07
Goshen	Yes	2,814	$ 1,527.85	$ 25.66	5.354%	$83.18	16.67%	85%	$38.77	0.00%	$0.00	$38.77	$121.94	$83.52
Wasatch Front	Yes	4,225	$ 1,542.83	$ 25.66	4.452%	$69.83	16.67%	85%	$38.77	0.00%	$0.00	$38.77	$108.60	$74.38
Wyoming East	Yes	6,130	$ 1,482.92	$ 25.66	4.452%	$67.16	16.67%	85%	$38.77	0.00%	$0.00	$38.77	$105.93	$72.55
Li-Ion, 4-hour, 200 MW + Δ Double Duration, Li-Ion, 4-hour, 200MW[1]	Yes	N/A	$ 2,556.57	$ 46.19	5.355%	$139.38	33.33%	85%	$69.78	0.00%	$0.00	$69.78	$209.16	$71.63
Portland North Coast	Yes	19	$ 2,709.97	$ 46.19	5.355%	$147.59	33.33%	85%	$69.78	0.00%	$0.00	$69.78	$217.37	$74.44
Southern OR	Yes	497	$ 2,761.10	$ 46.19	5.355%	$150.33	33.33%	85%	$69.78	0.00%	$0.00	$69.78	$220.11	$75.38
Walla Walla	Yes	2,353	$ 2,633.27	$ 46.19	5.355%	$143.48	33.33%	85%	$69.78	0.00%	$0.00	$69.78	$213.27	$73.04
Goshen	Yes	2,814	$ 2,607.71	$ 46.19	5.355%	$142.12	33.33%	85%	$69.78	0.00%	$0.00	$69.78	$211.90	$72.57
Wasatch Front	Yes	4,225	$ 2,633.27	$ 46.19	4.453%	$119.32	33.33%	85%	$69.78	0.00%	$0.00	$69.78	$189.10	$64.76
Wyoming East	Yes	6,130	$ 2,531.01	$ 46.19	4.453%	$114.76	33.33%	85%	$69.78	0.00%	$0.00	$69.78	$184.54	$63.20
Li-Ion, 4-hour, 1000 MW[1]	No	N/A	$ 1,459.50	$ 25.66	5.356%	$79.55	16.67%	85%	$36.92	0.00%	$0.00	$36.92	$116.47	$79.77
Gravity Battery, 4-hour, 1000 MW	Yes	N/A	$ 2,020.99	$ 0.19	2.916%	$58.94	16.67%	83%	$50.51	0.00%	$0.00	$50.51	$109.45	$74.97
Wasatch Front	Yes	4,225	$ 2,081.62	$ 0.19	2.916%	$60.71	16.67%	83%	$50.51	0.00%	$0.00	$50.51	$111.22	$76.18
Gravity Battery, 4-hour, 1000 MW + Δ Double Duration, Gravity, 4-hour, 1000MW	No	N/A	$ 3,006.34	$ 0.35	2.916%	$87.68	33.33%	83%	$90.92	5.48%	$4.98	$95.90	$183.58	$62.87
Adiabatic CAES, 500 MW, 4000 MWh	No	N/A	$ 3,754.00	$ 49.31	4.288%	$163.09	33.33%	63%	$19.20	0.00%	$0.00	$19.20	$182.29	$62.43
100-hour Iron Air	Yes	N/A	$ 2,729.67	$ 171.06	4.581%	$132.88	30.07%	43%	$21.04	2.62%	$0.55	$21.59	$154.47	$58.64
Portland North Coast	Yes	19	$ 2,893.45	$ 171.06	5.484%	$168.06	30.07%	43%	$21.04	2.62%	$0.55	$21.59	$189.65	$72.00
Wasatch Front	Yes	4,225	$ 2,811.56	$ 171.06	4.581%	$136.63	30.07%	43%	$21.04	2.62%	$0.55	$21.59	$158.22	$60.07
Pumped Hydro, Two New Reservoirs, 4-hour	No	N/A	$ 2,984.23	$ 149.21	3.121%	$97.79	16.67%	80%	$20.20	2.62%	$0.53	$20.73	$118.52	$81.18
Pumped Hydro, Two New Reservoirs, 10-hour	Yes	N/A	$ 4,158.90	$ 207.95	3.121%	$136.29	41.67%	80%	$20.20	2.62%	$0.53	$20.73	$157.02	$43.02
Portland North Coast	Yes	19	$ 4,408.44	$ 207.95	3.121%	$144.08	41.67%	80%	$20.20	2.62%	$0.53	$20.73	$164.81	$45.15
Southern OR	Yes	497	$ 4,491.61	$ 207.95	3.121%	$146.67	41.67%	80%	$20.20	2.62%	$0.53	$20.73	$167.40	$45.86
Goshen	Yes	2,814	$ 4,242.08	$ 207.95	3.121%	$138.89	41.67%	80%	$20.20	2.62%	$0.53	$20.73	$159.61	$43.73
Wasatch Front	Yes	4,225	$ 4,283.67	$ 207.95	2.582%	$115.97	41.67%	80%	$20.20	2.62%	$0.53	$20.73	$136.70	$37.45
Wyoming East	Yes	6,130	$ 4,117.31	$ 207.95	2.582%	$111.68	41.67%	80%	$20.20	2.62%	$0.53	$20.73	$132.41	$36.28
Pumped Hydro, One New Reservoir, 4-hour	No	N/A	$ 2,883.24	$ 144.16	3.121%	$94.49	16.67%	80%	$20.20	2.62%	$0.53	$20.73	$115.21	$78.91
Pumped Hydro, One New Reservoir, 10-hour	No	N/A	$ 3,537.41	$ 176.87	3.121%	$115.92	41.67%	80%	$20.20	2.62%	$0.53	$20.73	$136.65	$37.44
Pumped Thermal Energy Storage, 10-hour	No	N/A	$ 6,173.76	$ 60.00	3.361%	$209.52	35.48%	55%	$2.00	2.62%	$0.05	$2.05	$211.57	$68.06
Pumped Thermal Energy Storage, 24-hour	No	N/A	$ 11,525.17	$ 60.00	3.362%	$389.49	35.48%	55%	$1.00	1.37%	$0.01	$1.01	$390.51	$125.63

[1]Assumed co-located

Table 7.9 – 2025 IRP Thermal Supply-Side Resources, Variable O&M, Total Cost and Credits (2024$)

	Variable O&M					Credits		
Resource Description	Levelized Fuel ($/MWh)	O&M ($/MWh)	Capitalized Premium	O&M Capitalized ($/MWh)	Total Resource Cost ($/MWh)	Tax Credits ($/MWh) (ITC already applied)	Total Resource Cost with PTC / ITC Credits ($/MWh)	Total Fixed Cost with Tax Credit ($/kW-yr)
Internal Combustion Engine, renewable biofuel, with SCR & 24-hour fuel tank	$ 357.85	$6.93	14.39%	$1.00	$389.44	-	$389.44	$191.77
SCCT Aero, with SCR	$ 53.04	$7.40	14.39%	$1.07	$121.75	-	$121.75	$174.13
SCCT Aero x4, with SCR	$ 53.04	$5.92	14.39%	$0.85	$101.81	-	$101.81	$121.40
SCCT Frame "F" x1, with SCR	$ 54.56	$7.75	14.39%	$1.12	$102.86	-	$102.86	$114.00
Goshen	$ 55.25	$7.75	14.39%	$1.12	$137.12	-	$137.12	$211.04
Wasatch Front	$ 55.27	$7.75	14.39%	$1.12	$108.37	-	$108.37	$127.87
Wyoming East	$ 47.47	$7.75	14.39%	$1.12	$104.40	-	$104.40	$138.95
CCCT Dry "H", 1X1, DF, with SCR	$ 33.91	$2.70	14.39%	$0.39	$60.26	-	$60.26	$158.93
Goshen	$ 34.65	$2.70	14.39%	$0.39	$70.00	-	$70.00	$220.41
Wasatch Front	$ 34.74	$2.70	14.39%	$0.39	$62.27	-	$62.27	$167.04
Wyoming East	$ 30.05	$2.70	14.39%	$0.39	$58.62	-	$58.62	$174.11
CCCT Dry "H", 2X1, DF, with SCR	$ 34.37	$2.28	14.39%	$0.33	$56.54	-	$56.54	$133.67
Goshen	$ 35.12	$2.28	14.39%	$0.33	$66.39	-	$66.39	$195.80
Wasatch Front	$ 35.21	$2.28	14.39%	$0.33	$58.61	-	$58.61	$142.08
Wyoming East	$ 30.45	$2.28	14.39%	$0.33	$54.90	-	$54.90	$149.26
CCCT Dry "H", 1X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 1x1	$ 37.86	$5.32	11.52%	$0.61	$87.60	-	$87.60	$299.37
CCCT Dry "H", 2X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 2x1	$ 38.42	$4.83	11.52%	$0.56	$80.12	-	$80.12	$248.16
Internal Combustion Engine, renewable biofuel, with SCR + Δ for CT Brownfield construction	$ 46.57	$6.24	14.39%	$0.90	$114.97	-	$114.97	$177.10
SCCT Aero, with SCR + Δ for CT Brownfield construction	$ 53.04	$6.66	14.39%	$0.96	$115.39	-	$115.39	$158.21
SCCT Aero x4, with SCR + Δ for CT Brownfield construction	$ 53.04	$5.33	14.39%	$0.77	$97.36	-	$97.36	$110.49
SCCT Frame "F" x1, with SCR + Δ for CT Brownfield construction	$ 54.56	$6.98	14.39%	$1.00	$99.05	-	$99.05	$105.53
Goshen-Brownfield	$ 54.23	$6.98	14.39%	$1.00	$132.26	-	$132.26	$202.50
Wasatch Front-Brownfield	$ 54.29	$6.98	14.39%	$1.00	$103.60	-	$103.60	$119.50
Wyoming East-Brownfield	$ 53.90	$6.98	14.39%	$1.00	$107.05	-	$107.05	$130.57
CCCT Dry "H", 1X1, DF, with SCR + Δ for CT Brownfield construction	$ 33.91	$2.43	14.39%	$0.35	$58.28	-	$58.28	$147.48
Goshen-Brownfield	$ 34.01	$2.43	14.39%	$0.35	$67.36	-	$67.36	$208.85
Wasatch Front-Brownfield	$ 34.12	$2.43	14.39%	$0.35	$59.69	-	$59.69	$155.71
Wyoming East-Brownfield	$ 34.12	$2.43	14.39%	$0.35	$60.72	-	$60.72	$162.78
CCCT Dry "H", 2X1, DF, with SCR + Δ for CT Brownfield construction	$ 34.37	$2.05	14.39%	$0.30	$54.87	-	$54.87	$123.99
Goshen-Brownfield	$ 34.48	$2.05	14.39%	$0.30	$64.05	-	$64.05	$186.02
Wasatch Front-Brownfield	$ 34.58	$2.05	14.39%	$0.30	$56.32	-	$56.32	$132.50
Wyoming East-Brownfield	$ 34.58	$2.05	14.39%	$0.30	$57.37	-	$57.37	$139.67
CCCT Dry "H", 1X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 1x1 + Δ for CT Brownfield construction	$ 37.86	$4.78	11.52%	$0.55	$83.88	-	$83.88	$278.00
CCCT Dry "H", 2X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 2x1 + Δ for CT Brownfield construction	$ 38.42	$4.34	11.52%	$0.50	$76.99	-	$76.99	$230.43
SCCT Frame "F" x1, with SCR + Δ for 100%Hydrogen burning capability	$ 54.56	$8.91	14.39%	$1.28	$105.86	-	$105.86	$118.83
CCCT Dry "H", 1X1, DF, with SCR + Δ for 100%Hydrogen burning capability	$ 33.91	$3.11	14.39%	$0.45	$61.30	-	$61.30	$162.85
CCCT Dry "H", 2X1, DF, with SCR + Δ for 100%Hydrogen burning capability	$ 34.37	$2.62	14.39%	$0.38	$57.42	-	$57.42	$136.97
SCCT Frame "F" x1, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	$ 54.56	$8.18	14.39%	$1.18	$160.18	-	$160.18	$278.30
CCCT Dry "H", 1X1, DF, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	$ 33.91	$3.13	14.39%	$0.45	$86.46	-	$86.46	$334.59
CCCT Dry "H", 2X1, DF, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	$ 34.37	$2.70	14.39%	$0.39	$81.51	-	$81.51	$300.93
SCCT Frame "F" x1, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	$ 54.56	$8.32	14.39%	$1.20	$146.59	-	$146.59	$238.51
CCCT Dry "H", 1X1, DF, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	$ 33.91	$3.27	14.39%	$0.47	$80.83	-	$80.83	$294.99
CCCT Dry "H", 2X1, DF, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	$ 34.37	$2.85	14.39%	$0.41	$75.86	-	$75.86	$261.22
CCCT Dry "H", 1X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 1x1	$ 33.91	$2.68	14.39%	$0.39	$60.00	-	$60.00	$157.33
CCCT Dry "H", 2X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 2x1	$ 34.37	$2.23	14.39%	$0.32	$56.00	-	$56.00	$130.32
CCCT Dry "H", 1X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 1x1, 95% CCS	$ 37.86	$5.03	11.52%	$0.58	$85.02	-	$85.02	$283.94
CCCT Dry "H", 2X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 2x1, 95% CCS	$ 38.42	$4.49	11.52%	$0.52	$77.00	-	$77.00	$229.40
Hydrogen peaker with CCCT Dry "H", 2X1, DF and electrolyzer	$ -	$0.00	0.00%	$0.00	$21.20	$ (4.85)	$21.20	$182.03
Electrolyzer, Proton Exchange Membrane (PEM), 50,000 kg/day	$ -	$23.91	0.00%	$0.00	$28.03	$ (0.96)	$28.03	$35.03
CCS Dave Johnston 4 (costs on post retrofit basis)	$ -	$11.40	11.52%	$1.31	$82.84	$ (160.13)	$ (77.29)	$ (487.20)
CCS Hunter 1-3 (costs on post retrofit basis)	$ -	$9.73	11.52%	$1.12	$70.24	$ (160.13)	$ (89.89)	$ (565.96)
CCS Huntington 1&2 (costs on post retrofit basis)	$ -	$9.63	11.52%	$1.11	$71.09	$ (160.13)	$ (89.04)	$ (562.82)
CCS Jim Bridger 3&4 (costs on post retrofit basis)	$ -	$10.57	11.52%	$1.22	$70.90	$ (160.13)	$ (89.23)	$ (554.00)
CCS Wyodak (costs on post retrofit basis)	$ -	$11.69	11.52%	$1.35	$87.70	$ (160.13)	$ (72.43)	$ (459.16)
Small Modular Reactor or Advanced Reactor, Moderate Technology Case	$ -	$9.74	0.00%	$0.00	$82.73	$ (20.29)	$62.44	$448.80
Goshen	$ -	$9.74	0.00%	$0.00	$83.93	$ (20.29)	$63.64	$458.27
Wasatch Front	$ -	$9.74	0.00%	$0.00	$83.93	$ (22.29)	$61.64	$443.88
Wyoming East	$ -	$9.74	0.00%	$0.00	$82.13	$ (22.29)	$59.85	$429.73
Small Modular Reactor or Advanced Reactor, Advanced Technology Case	$ -	$8.74	0.00%	$0.00	$59.58	$ (22.29)	$37.29	$259.26
Small Modular Reactor or Advanced Reactor, Moderate Technology Case + Δ for nuclear integrated thermal storage	$ -	$10.72	0.00%	$0.00	$90.99	$ (20.29)	$70.71	$508.18
Small Modular Reactor or Advanced Reactor, Advanced Technology Case + Δ for nuclear integrated thermal storage	$ -	$9.61	0.00%	$0.00	$65.53	$ (22.29)	$43.24	$300.62
Large Light Water Reactor, Moderate Technology Case	$ -	$9.38	0.00%	$0.00	$73.09	$ (20.29)	$52.80	$374.94
Large Light Water Reactor, Advanced Technology Case	$ -	$7.88	0.00%	$0.00	$58.83	$ (22.29)	$36.55	$257.87
Near Field Enhanhanced Geothermal System (NF-EGS) Binary	$ -	$0.00	0.00%	$0.00	$96.89	$ (23.46)	$73.43	$514.59
Southern OR	$ -	$0.00	0.00%	$0.00	$108.42	$ (23.46)	$84.96	$595.43
Wasatch Front	$ -	$0.00	0.00%	$0.00	$96.89	$ (25.77)	$71.12	$498.40

* Δ for CCS installation on existing coal units is for CCS costs and operating characterisitics only, not the operation of the existing coal resource.

Table 7.10 – 2025 IRP Non-Thermal Supply-Side Resources, Variable O&M, Total Cost and Credits (2024$)

Resource Description	Total Resource Cost ($/MWh)	Credits		
		Tax Credits ($/MWh) (ITC already applied)	Total Resource Cost with PTC / ITC Credits ($/MWh)	Total Fixed Cost with Tax Credit ($/kW-yr)
PV, 20 MW, Class 1-10	$65.11	$ (25.15)	$39.96	$95.69
Portland North Coast	$76.45	$ (25.15)	$51.30	$110.04
Southern OR	$66.54	$ (25.15)	$41.39	$106.20
Walla Walla	$69.74	$ (25.15)	$44.59	$101.40
Goshen	$64.59	$ (25.15)	$39.44	$96.03
Wasatch Front	$61.38	$ (27.63)	$33.75	$85.73
Wyoming East	$64.79	$ (27.63)	$37.16	$89.42
PV, 200 MW, Class 1-10	$44.24	$ (25.15)	$19.09	$45.72
Portland North Coast	$51.72	$ (25.15)	$26.57	$56.99
Southern OR	$44.87	$ (25.15)	$19.72	$50.59
Walla Walla	$47.32	$ (25.15)	$22.17	$50.41
Goshen	$43.86	$ (25.15)	$18.71	$45.54
Wasatch Front	$41.71	$ (27.63)	$14.08	$35.76
Wyoming East	$44.02	$ (27.63)	$16.40	$39.46
PV, 20 MW, Class 1-10 + Δ Advanced Solar Technology Case	$60.88	$ (27.63)	$33.25	$79.62
PV, 200 MW, Class 1-10 + Δ Advanced Solar Technology Case	$41.42	$ (27.63)	$13.80	$33.03
Wind Class 1-10, 20 MW	$80.60	$ (23.46)	$57.14	$145.49
Portland North Coast	$102.14	$ (23.46)	$78.68	$171.70
Southern OR	$106.14	$ (23.46)	$82.68	$182.40
Walla Walla	$104.46	$ (23.46)	$81.00	$164.12
Goshen	$69.45	$ (23.46)	$45.99	$138.03
Wasatch Front	$70.08	$ (25.77)	$44.31	$130.77
Wyoming East	$69.41	$ (25.77)	$43.64	$127.01
Wind Class 1-6, 200 MW	$42.12	$ (23.46)	$18.66	$56.18
Portland North Coast	$41.47	$ (23.46)	$18.01	$59.36
Southern OR	$47.92	$ (23.46)	$24.46	$72.97
Walla Walla	$45.68	$ (23.46)	$22.22	$63.43
Goshen	$48.49	$ (23.46)	$25.03	$66.38
Wasatch Front	$47.93	$ (25.77)	$22.16	$59.04
Wyoming East	$34.60	$ (25.77)	$8.83	$31.90
Wind Class 7, 200 MW	$43.59	$ (23.46)	$20.13	$60.59
Offshore, Wind Class 12	$186.38	$ (32.72)	$186.38	$514.98
Southern OR	$138.33	$ (24.88)	$138.33	$593.07
Wind Class 1-10, 20 MW + Δ Advanced Onshore Wind Technology Case	$75.95	$ (25.77)	$50.18	$127.76
Wind Class 1-6, 200 MW + Δ Advanced Onshore Wind Technology Case	$39.54	$ (25.77)	$13.77	$41.47
Wind Class 7, 200 MW + Δ Advanced Onshore Wind Technology Case	$40.94	$ (25.77)	$15.17	$45.68
Offshore, Wind Class 12 + Δ Advanced Offshore Wind Technology Case	$49.06	$ (11.74)	$49.06	$362.89

Table 7.11 – 2025 IRP Storage Supply-Side Resources, Variable O&M, Total Cost and Credits (2024$)

Resource Description	Variable O&M	Credits	
	O&M ($/MWh)	Tax Credits ($/MWh) (ITC already applied)	Total Fixed Cost with Tax Credit ($/kW-yr)
Ion, 4-hour, 20 MW[1]	$0.00	$ (32.40)	$140.22
Ion, 4-hour, 200 MW[1]	$0.00	$ (27.77)	$120.34
Portland North Coast	$0.00	$ (29.44)	$125.15
Southern OR	$0.00	$ (29.99)	$126.75
Walla Walla	$0.00	$ (28.61)	$122.74
Goshen	$0.00	$ (28.33)	$121.94
Wasatch Front	$0.00	$ (38.14)	$108.60
Wyoming East	$0.00	$ (36.66)	$105.93
Ion, 4-hour, 200 MW + Δ Double Duration, Li-Ion, 4-hour, 200MW[1]	$0.00	$ (23.69)	$209.16
Portland North Coast	$0.00	$ (25.11)	$217.37
Southern OR	$0.00	$ (25.59)	$220.11
Walla Walla	$0.00	$ (24.40)	$213.27
Goshen	$0.00	$ (24.17)	$211.90
Wasatch Front	$0.00	$ (32.54)	$189.10
Wyoming East	$0.00	$ (31.27)	$184.54
Ion, 4-hour, 1000 MW[1]	$0.00	$ (27.05)	$116.47
Gravity Battery, 4-hour, 1000 MW	$0.00	$ (33.10)	$109.45
Wasatch Front	$0.00	$ (34.09)	$111.22
Gravity Battery, 4-hour, 1000 MW + Δ Double Duration, Gravity, 4-hour, 1000MW	$0.00	$ (24.62)	$183.58
Adiabatic CAES, 500 MW, 4000 MWh	$2.60	$ (27.92)	$182.29
100-hour Iron Air	$0.00	$ (37.40)	$154.47
Portland North Coast	$0.00	$ (29.72)	$189.65
Wasatch Front	$0.00	$ (38.52)	$158.22
Pumped Hydro, Two New Reservoirs, 4-hour	$0.58	$ (33.01)	$118.52
Pumped Hydro, Two New Reservoirs, 10-hour	$0.58	$ (18.40)	$157.02
Portland North Coast	$0.58	$ (19.51)	$164.81
Southern OR	$0.58	$ (19.87)	$167.40
Goshen	$0.58	$ (18.77)	$159.61
Wasatch Front	$0.58	$ (25.28)	$136.70
Wyoming East	$0.58	$ (24.30)	$132.41
Pumped Hydro, One New Reservoir, 4-hour	$0.58	$ (31.89)	$115.21
Pumped Hydro, One New Reservoir, 10-hour	$0.58	$ (15.65)	$136.65
Pumped Thermal Energy Storage, 10-hour	$0.70	$ (34.12)	$211.57
Pumped Thermal Energy Storage, 24-hour	$0.70	$ (63.70)	$390.51

1Assumed co-located

Table 7.12 - Glossary of Terms Used in the Supply-Side Resource Tables

Term	Description
Fuel	Primary fuel used for electricity generation or storage.
Resource	Primary technology used for electricity generation or storage.
Elevation (afsl)	Average feet above sea level for the proxy site for the given resource.
Net Capacity (MW)	For natural gas-fired generation resources, the Net Capacity is the net dependable capacity (net electrical output) for a given technology, at the given elevation, at the annual average ambient temperature in a "new and clean" condition.
Resource Availability Year	The earliest year the Company would sign a contract for a Resource being studied in this IRP. If available prior to the development of this database, this defaults to IRP year.
Total Implementation Time	Number of years necessary to implement all phases of resource development and construction after signing a contract to build the Resource: permitting (e.g., air, land, water, and wildlife), maintenance contracts, owner's engineering, construction, testing, and grid interconnection.
Commercial Operation Year	Year when the Resource is available for generation and dispatch. It is based on the Resource Availability Year plus the Total Implementation Time.
Design Life (years)	Average number of years the resource is expected to be "used and useful."
Base Capital ($/kW)	Total capital expenditure in dollars per kilowatt ($/kW) for the development and construction of a Resource including: direct costs (equipment, buildings, installation/overnight construction, commissioning, contractor fees/profit, and contingency), owner's costs (land, water rights, permitting, rights-of-way, design engineering, spare parts, project management, legal/financial support, grid interconnection costs, and owner's contingency), and financial costs (allowance for funds used during construction (AFUDC), capital surcharge, property taxes, and escalation during construction, if applicable).
Var O&M ($/MWh)	Includes real levelized variable operating costs such as combustion turbine maintenance, water costs, boiler water/circulating water treatment chemicals, pollution control reagents, equipment maintenance, and fired hour fees in dollars per megawatt hour ($/MWh).
Fixed O&M ($/kW-year)	Includes labor costs, combustion turbine fixed maintenance fees, contracted services fees, office equipment, and training.
Demolition Cost ($/kW)	Total cost to decommission and demolish the generating unit at the end of life in dollars per kilowatt ($/kW).
Full Load Heat Rate HHV (Btu/kWh)	Net efficiency of the resource to generate electricity for a given heat input in a "new and clean" condition on a higher heating value basis.
Efficiency	Typical operational round-trip efficiency of energy storage of alternating current (AC) energy delivered to the grid divided by AC energy stored from the grid.

Term	Description
EFOR (%)	Estimated Equivalent Forced Outage Rate, which includes forced outages and derates for a given Resource at the given site.
POR (%)	Estimated Planned Outage Rate for a given Resource at the given site.
Water Consumed (gal/MWh)	Average amount of water consumed by a Resource for make-up, cooling water make-up, inlet conditioning and pollution control.
SO2 (lbs/MMBtu)	Expected permitted level of sulfur dioxide (SO2) emissions in pounds of sulfur dioxide per million Btu of heat input.
NOx (lbs/MMBtu)	Expected permitted level of nitrogen oxides (NOx) (expressed as NO2) in pounds of NOx per million Btu of heat input.
Hg (lbs/TBtu)	Expected permitted level of mercury emissions in pounds per trillion Btu of heat input.
CO2 (lbs/MMBtu)	Pounds of carbon dioxide (CO2) emitted per million Btu of heat input.

Table 7.13 - Glossary of Acronyms Used in Chapter 7

Acronyms	Description
ACAES	Adiabatic Compressed Air Energy storage
AFSL	Average Feet (Above) Sea Level
ATB	Annual Technology Baseline
CAES	Compressed Air Energy Storage
CCCT	Combined Cycle Combustion Turbine
CCS	Carbon Capture and Storage
CCUS	Carbon Capture, Utilization and Storage
CF	Capacity Factor
CSP	Concentrated Solar Power
CT	Combustion Turbine
DF	Duct Firing
DOE	United States Department of Energy
EIA	Energy Information Agency
FGD	Flue Gas Desulfurization
GAIN	Gateway for Accelerated Innovation in Nuclear
HRSG	Heat Recovery Steam Generator
ICE	Internal Combustion Engine (reciprocating engine)
IGCC	Integrated Gasification Combined Cycle
ISO	International Standards Organization (Temperature = 59 degrees Fahrenheit (°F) / 15 degrees Celsius (°C), Pressure = 14.7 psia/1.013 bar)
Li-Ion	Lithium Ion
LFP	Lithium Iron Phosphate (sub-chemistry of lithium-ion)
MW	Megawatt
NCM	Nickel Cobalt Manganese (sub-chemistry of lithium-ion)
NREL	National Renewable Energy Laboratory
OEM	Original Equipment Manufacturer
OSTI	Office of Scientific and Technical Information

OSW	Offshore Wind
PCCC	Post Combustion CO2 Capture
PEM	Proton Exchange Membrane
PPA	Power Purchase Agreement
PC CCUS	Pulverized Coal retrofitted with Carbon Capture, Utilization and Storage
PHES	Pumped Hydro Energy Storage
PV Poly-Si	Photovoltaic modules constructed from poly-crystalline silicon semiconductor wafers
Recip	Reciprocating Engine
RTE	Round Trip Efficiency (typical operational AC to AC energy storage efficiency)
SCCT	Simple Cycle Combustion Turbine
SCR	Selective catalytic reduction
STG	Steam turbine generator

Resource Option Descriptions

The following are brief descriptions of each of the resources listed in Table 7.2 through Table 7.11. For all technology that is included in the 2024 NREL ATB, the ATB costs were used. For incremental items, a percentage difference between the technology with and without the incremental resource was used. Where data is available for an advanced technology innovation scenario[24], there is a resource row for that scenario.

Internal Combustion Engine x4, renewable biofuel, with SCR & fuel tank – This is a reciprocating internal combustion engine (RICE) power plant based on four large-scale engines, that are assumed to burn a liquid renewable biofuel like biodiesel or renewable diesel. Each engine is rated nominally at 5.6 MW with a net capacity of 21.4 MW."[25] It is presented in the IRP as a 20 MW resource to meet Oregon's regulatory requirements for distributed generation resources, under the assumption that it could be derated to meet the requirements. The 24-hour fuel tank was added to the 2020 EIA Report's resource based on available market information on in-ground fuel tanks.[26]

Natural Gas, Simple Combined Cycle Turbine (SCCT) Aero x 4 – This is "four of aeroderivative dual-fuel CTs in a simple-cycle configuration, with a nominal output of approximately 54 MW gross per turbine. After deducting internal auxiliary power demand, the net output of the plant is approximately 211 MW. Each CT's inlet air duct has an evaporative cooler to reduce the inlet air temperature in warmer seasons to increase the CT output. Each CT is also

[24] https://atb.nrel.gov/electricity/2024/definitions#scenarios
[25] *Cost and Performance Estimates for New Utility-Scale Electric Power Generating Technologies*, December 2019, Sargent & Lundy, prepared for the U.S. Energy Information Administration's *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies*, February 2020 https://www.eia.gov/analysis/studies/powerplants/capitalcost/archive/2020/pdf/capital_cost_AEO2020.pdf
[26] See Appendix M, stakeholder feedback form #59 (Renewable Northwest).

equipped with burners designed to reduce the CT's emission of NO_X. Included are SCR units for further reduction of NO_X emissions and CO catalysts for further reduction of CO emissions."[27]

Natural Gas, SCCT Frame "F" x 1, with SCR – This is "one industrial frame Model F dual fuel CT in simple-cycle configuration with a nominal output of 237.2 MW gross. After deducting internal auxiliary power demand, the net output of the plant is 232.6 MW. The inlet air duct for the CT is equipped with an evaporative cooler to reduce the inlet air temperature in warmer seasons to increase the CT output. The CT is also equipped with burners designed to reduce the CT's emission of NO_X."[28] Although the 2020 EIA Report does not include an SCR for this resource, to be on par with the other IRP resources, the approximate cost of an SCR was added based on the cost difference on a percentage basis from previous IRP's.

Natural Gas, CCCT "H", 1x1, DF, with SCR – This is "one Model HL dual-fuel CT in a 1x1x1 single-shaft CC configuration. The CT generates approximately 453 MW gross, and the STG generates 192 MW gross. After deducting internal auxiliary power demand, the net output of the plant is approximately 627 MW."[29]

Natural Gas, CCCT "H", 2x1, DF, with SCR – This is "a pair of Model H, dual-fuel CTs in a 2x2x1 CC configuration (two CTs, two heat recovery steam generators [HRSGs], and one steam turbine). Each CT generates approximately 436 MW gross; the STG generates approximately 393 MW gross. After deducting internal auxiliary power demand, the net output of the plant is 1227 MW."[30]

Natural Gas, Δ for adding 95% CCS – This option reflects incremental changes for a greenfield "power plant w/ commercially available solvent-based post combustion CO_2 capture (PCCC) designed for 95% capture."[31] The 95% option was chosen because that is the most economic option available in the NREL ATB that meets the EPA 111 regulations.

Natural Gas, Δ for CT Brownfield construction – This option reflects incremental changes for construction of a resource at an existing powerplant site with the same technology.

Hydrogen, Δ for 100% Hydrogen burning capability – This option reflects incremental changes for a CT to burn a mixture of fuel up to 100% hydrogen.

Hydrogen, Δ for Hydrogen storage, cavern, 80 bar, 1 week – This option reflects incremental changes for storing hydrogen underground in a solution-mined geologic salt dome. Hydrogen gas

[27] *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies*, December 6, 2023, Sargent & Lundy, prepared for the U.S. Energy Information Administration's *Capital Cost and Performance Characteristics for Utility Scale Electric Power Generating Technologies*, January 2024. https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf
[28] *Cost and Performance Estimates for New Utility-Scale Electric Power Generating Technologies*, December 2019, Sargent & Lundy, prepared for the U.S. Energy Information Administration's *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies*, February 2020 https://www.eia.gov/analysis/studies/powerplants/capitalcost/archive/2020/pdf/capital_cost_AEO2020.pdf
[29] *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies*, December 6, 2023, Sargent & Lundy, prepared for the U.S. Energy Information Administration's *Capital Cost and Performance Characteristics for Utility Scale Electric Power Generating Technologies*, January 2024. https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf
[30] Ibid 17
[31] 2024 ATB Excel Workbook, available at https://atb.nrel.gov/electricity/2024/data.

is compressed and stored at ambient temperature in at elevated pressure (70-190 bar). Salt domes only exist in a limited number of locations (~2000 salt caverns in North America with an average capacity of 10^5-10^6 m^3). There are at least two salt domes under development within PacifiCorp's area of operation. This assumes a "600 tons per day (TPD) pipeline throughput for 7-days at 80 bar; cushion gas is ~40% of volume."[32] In addition to the Pathways to Commercial Liftoff: Clean Hydrogen (Clean Hydrogen Liftoff Report), the Hydrogen and Fuel Cell Technologies Office Multi-Year Program Plan[33] was used for cost and technical data.

Hydrogen, Δ for Hydrogen storage, tanks, 500 bar, 24-hour – This option reflects incremental changes for storing hydrogen in tanks constructed above ground. "H_2 gas is compressed at ambient temperature to 300 – 700 bar. Storage capacity is limited due to the low volumetric density of H_2 at room temperature. Assumes 950 kg stored at 500 bar with 1 cycle per week."[34]

Electrolyzer, Proton Exchange Membrane (PEM), 50,000 kg/day – Also known as polymer electrolyte membrane, including balance of plant (BOP) costs, the "electrolyzer design is intended to represent the current state-of-the-art (2022) stacks with respect to catalyst loadings (3 milligrams per square centimeter [mg/cm2] total platinum group metal [PGM] loading) and material specifications."[35] Data from the DOE Hydrogen and Fuel Cells Program Record[36] was also used in the development of this resource.

Coal, CCS– These are retrofits of an existing conventional coal-fired boiler and steam-turbine generator resources with amine based post-combustion carbon capture technology. Costs include the reduction in plant output due to higher auxiliary power requirements and reduced steam turbine output. The CCS would remove 95 percent of the carbon dioxide and would provide reductions in other emissions.[37]

Storage, Lithium Ion Battery – This is lithium-ion batteries rated at 20 and 200 MW capacities with 4-hour duration. The 20 MW option uses the ATB's "Commercial Battery" data, while the 200 MW option uses the ATB's "Utility-Scale" data.

[32] Pathways to Commercial Liftoff: Clean Hydrogen, U.S. Department of Energy, Office of Technology Transitions: Hannah Murdoch; Office of Clean Energy Demonstrations: Jason Munster; Hydrogen & Fuel Cell Technologies Office: Sunita Satyapal, Neha Rustagi; Argonne National Laboratory: Amgad Elgowainy; National Renewable Energy Laboratory: Michael Penev, https://liftoff.energy.gov/wp-content/uploads/2023/05/20230523-Pathways-to-Commercial-Liftoff-Clean-Hydrogen.pdf

[33] Hydrogen and Fuel Cell Technologies Office Multi-Year Program Plan, Dr. Sunita Satyapal, U.S. Department of Energy, https://www.energy.gov/eere/fuelcells/hydrogen-and-fuel-cell-technologies-office-multi-year-program-plan

[34] ibid 20

[35] Badgett, Alex, Joe Brauch, Amogh Thatte, Rachel Rubin, Christopher Skangos, Xiaohua Wang, Rajesh Ahluwalia, Bryan Pivovar, and Mark Ruth. 2024. *Updated Manufactured Cost Analysis for Proton Exchange Membrane Water Electrolyzers*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-87625. https://www.nrel.gov/docs/fy24osti/87625.pdf.

[36] David Peterson, James Vickers, Dan DeSantis, *Hydrogen Production Cost From PEM Electrolysis – 2019*, February 3, 2020, https://www.hydrogen.energy.gov/docs/hydrogenprogramlibraries/pdfs/19009_h2_production_cost_pem_electrolysis_2019.pdf?Status=Master

[37] Carbon capture costs and parameters were the subject of discussion and feedback during the 2025 IRP public input meeting series.
See Appendix M, stakeholder feedback form #25 (NP Energy, LLC).
See Appendix M, stakeholder feedback form #44 (Sierra Club).

Storage, Δ double duration – This option reflects incremental changes for doubling the duration of a battery energy storage resource, modifiers on this row must be applied to the data in the appropriate resource row. Appropriate resources are limited to those utilizing lithium-ion energy storage, including lithium-ion energy storage collocated with other resources.

Storage, Δ for Co-Located Energy Storage – This option reflects incremental changes for lithium-ion energy storage collocated with another resource, modifiers on this row must be applied to the appropriate energy storage data.

Storage, Gravity Battery, 4-hour, 1000 MW – This is an estimate for any technology that uses the potential energy differential of a large mass but excludes pumped hydro. Pumped hydro is a well-established technology and because of this there is more accurate data available for pumped hydro. Examples include dense weights lifted vertically, heavy rail cars moved up and down a steep track, or a piston displacing a fluid vertically. Costs were escalated from the 2023 IRP.

Storage, Adiabatic CAES – Compressed air energy storage (CAES) system consists of an air storage reservoir pressurized by a compressor similar to a conventional gas turbine compression section but driven by an electric motor coupled with an adiabatic power generation turbine. The compressed air powers the adiabatic turbine. Energy is stored by compressing air into the storage reservoir. Only the system sizes of 500 MW are included because that size was the lowest cost per kWh in the 2023 IRP. The air storage reservoir is an engineered tank. "Adiabatic" conserves heat during storage and discharge and means the system does not burn natural gas to generate power.

Storage, Pumped Hydro, Two New Reservoirs – Also known as closed-loop pumped hydro, this technology pumps and releases water between a higher and a lower reservoir. It is modeled as a nominal 400 MW PHES system using a combination of natural and constructed water storage combined with elevation difference to enable a system capable of discharging the rated capacity for 10 or 4 hours. The development and construction time is estimated at 5 years assuming that early permitting and development has occurred prior to contracting with PacifiCorp. The IRP uses ATB National Class 1 data.

Storage, Pumped Hydro, One New Reservoirs – Also known as an open-loop system, this technology pumps and releases water between a higher reservoir and a lower natural water body, usually a river. It is modeled as a nominal 400 MW PHES system using both natural and constructed water storage combined with elevation difference to enable a system capable of discharging the rated capacity for 10 or 4 hours. The development and construction time is estimated at 5 years assuming that early permitting and development has occurred prior to contracting with PacifiCorp. The IRP uses ATB National Class 5 data.

Storage, 100-hour Iron Air – This is a low capital cost battery option with the trade off a low round trip efficiency. "While discharging, the battery breathes in oxygen from the air and converts iron metal to rust. While charging, the application of an electrical current converts the rust back to iron and the battery breathes out oxygen."[38]

Storage, Pumped Thermal Energy Storage – This is a system using a storage tank of high temperature fluid to store energy. A resistive heater converts electric energy to heat energy in the

[38] https://formenergy.com/technology/battery-technology/

fluid. To generate electricity, the fluid boils water which powers a steam turbine attached to electric generator.

Solar, PV, Class 1 - 10 – This is ATB PV Class 1 through 10 (20 MW or 200 MW) solar photovoltaic resources using crystalline silica solar panels in a single axis tracking system. The 20 MW option uses the ATB's "Commercial" data, while the 200 MW option uses the ATB's "Utility-Scale" data. A consultant was hired to provide location specific capacity factors for each node modeled in PLEXOS.

Wind, Wind Class 1-10, 20 MW – This is ATB "Distributed Wind, Large Turbine Technology Class." It is a wind resource of 1,500 kW turbines with 107-meter rotor diameter and 80-meter hub height. A consultant was hired to provide location specific capacity factors for each node modeled in PLEXOS.

Wind, Wind Class 1-6, and 7200 MW – This is ATB Land-Based Wind technology configuration T1. It is a wind resource of 34 x 6 MW turbines with 170-meter rotor diameter and 115-meter hub height. A consultant was hired to provide location specific capacity factors for each node modeled in PLEXOS.

Wind, Wind Class 7, 200 MW – This is the same as wind classes 1- 6, but different wind conditions and cost data.

Wind, Offshore, Wind Class 12 – This is ATB "Floating Offshore Wind." It is a wind resource of 12 MW turbines with 216-meter rotor diameter and 137-meter hub height. Wind Class 12 represents the wind conditions off the coast of northern California and southern Oregon. The ATB lists a net capacity factor of 47% for Offshore Wind Class 12.

Nuclear, Small Modular Reactor or Advanced Reactor – This is a conceptual technology that could be a small modular reactor or small advanced reactor. "Modular" refers to a reactor that can be built off site and easily transported to the installation location, however scale of economy requires multiple modular reactors to share support facilities at a single powerplant site. Data is from the ATB and relies heavily on a DOE Office of Scientific and Technical Information, Gateway for Accelerated Innovation in Nuclear report[39] ("OSTI GAIN Report").

Nuclear, Δ for nuclear integrated thermal storage, 5 hours - This option reflects incremental changes for a system using a storage tank of high temperature fluid. To store energy, heat from a nuclear reactor is transferred in a heat exchanger to the storage fluid. To generate electricity, the fluid boils water which powers a steam turbine attached to electric generator. This method eliminates the resistive heater losses in the stand-alone thermal storage, and therefore has a much higher RTE.

Nuclear, Large Light Water Reactor – This is a modern dual unit reactor similar to most of the existing utility reactors in the United States. Data is from the ATB and relies heavily on the OSTI GAIN Report.

[39] Abdalla Abou-Jaoude, Levi M Larsen, Nahuel Guaita, Ishita Trivedi, Frederick Joseck, and Christopher Lohse, Idaho National Laboratory; Edward Hoffman and Nicolas Stauff. Argonne National Laboratory; Koroush Shirvan, Massachusetts Institute of Technology; Adam Stein, Breakthrough Institute; Gateway for Accelerated Innovation in Nuclear (GAIN); *Meta-Analysis of Advanced Nuclear Reactor Cost Estimations*, July 2024, https://inldigitallibrary.inl.gov/sites/sti/sti/Sort_107010.pdf

Geothermal, Near Field Enhanced Geothermal System (NF-EGS) Binary – This is the ATB geothermal plant utilizing a 175°C thermal resource with 1.5 km wells and production well flow rates of 60 kg/s.[40]

Locational Modifiers and Selected Cost Forecasts

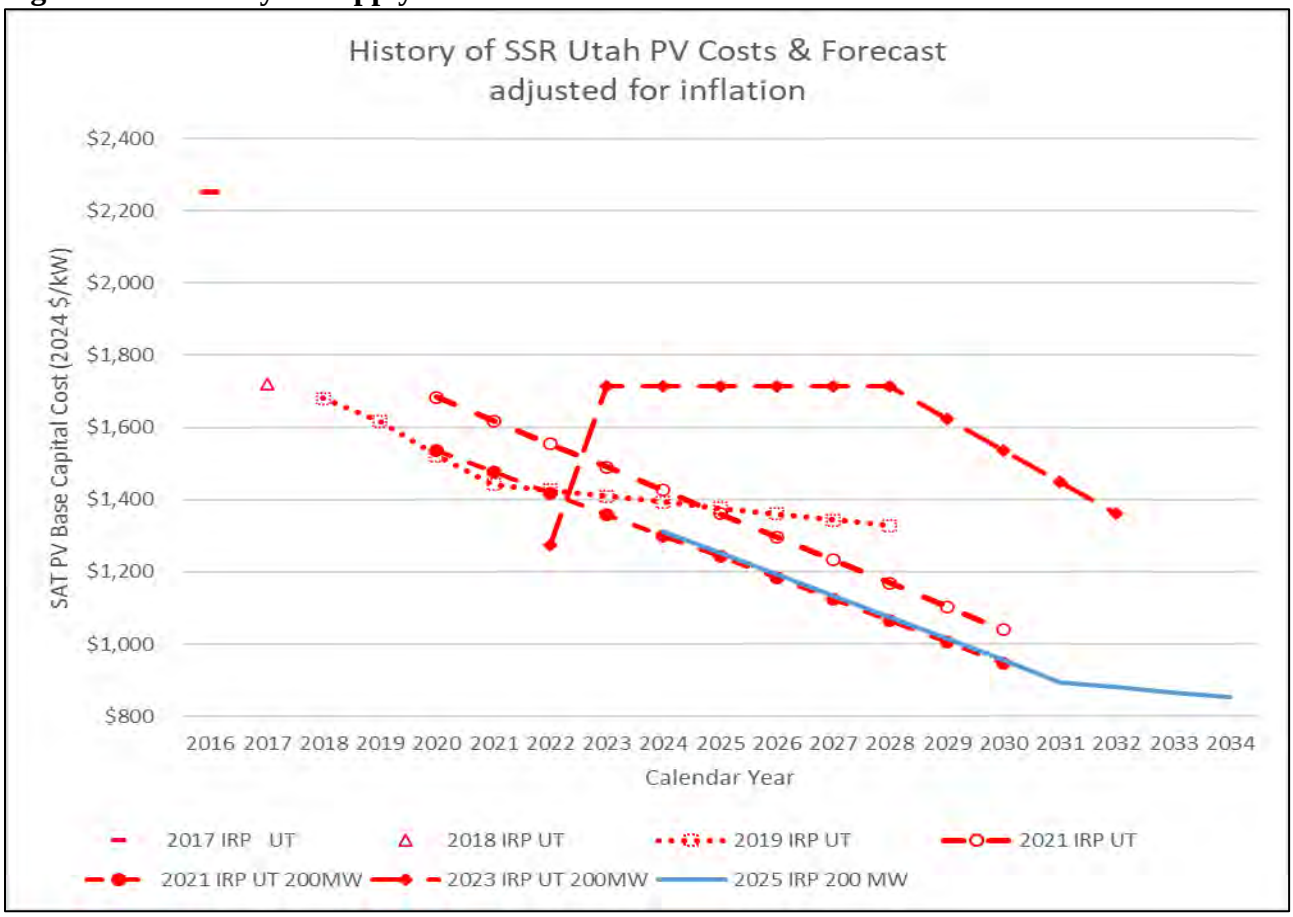
Appendix A of the EIA reports contain cost modifiers for selected cities within each state, and Appendix B of the EIA reports contains locational modifiers for combustion turbines that are largely dependent on altitude and ambient temperatures. The ATB contains cost forecasts for most resource options in the supply-side resource table. For any resource option without a technology specific cost forecast, escalation is assumed to be level. These locational modifiers and cost forecasts are applied in PLEXOS. Cost forecast histories for selected resource types are shown in the following sections.

PV Cost Forecast History

Figure 7.1 shows a history of capital cost forecasts used in the supply-side resource table for PV resources in Utah from 2017 through 2023 IRPs (the red lines). The 2025 IRP capital cost estimates for solar resources are based on the ATB forecast. The data from IRPs prior to 2021 was based on a 50 MW scale; however, the 50 MW scale is no longer included as a resource option. The solid blue line indicates the 2025 IRP price forecast at the 200 MW scale in Utah. The ATB forecast indicates that the observed market correction used in the 2023 IRP has been mitigated largely by federal policy changes and the forecast is essentially the same as the trend line of the 2021 IRP.

[40] Geothermal modeling was the subject of stakeholder feedback during the 2025 IRP public input meeting series.
See Appendix M, stakeholder feedback form #11 (Utah Environmental Caucus).
See Appendix M, stakeholder feedback form #41 (Nathan Strain).

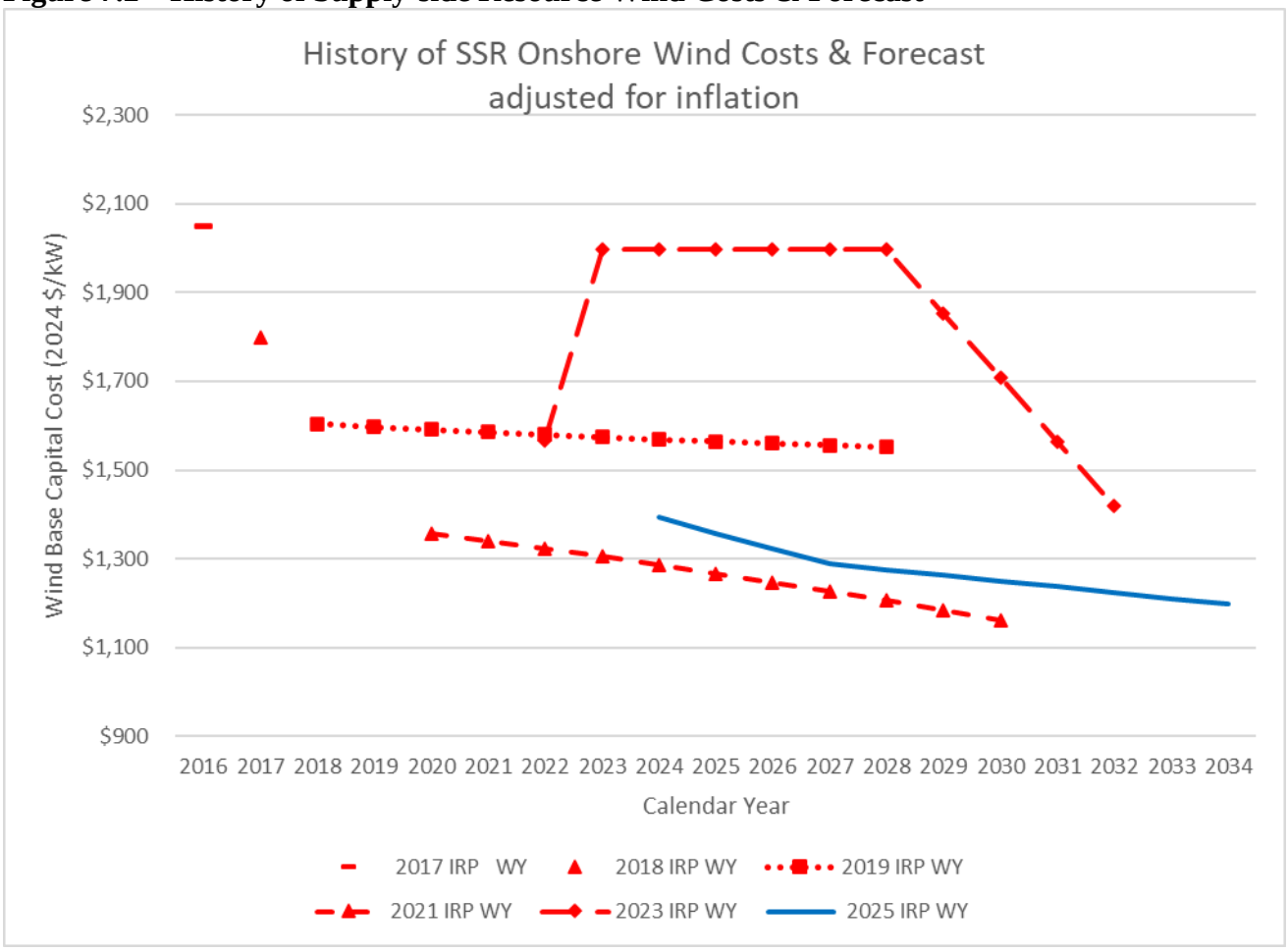
Figure 7.1 – History of Supply-side Resource PV Cost & Forecast



Wind Cost Forecast History

Figure 7.2 shows a history of capital cost forecasts used in the supply-side resource table for resources in Wyoming from 2017 through 2023 IRPs (the red lines). The 2025 IRP capital cost forecast for wind resources is based on the ATB forecast. The ATB forecast indicates that the observed market correction used in the 2023 IRP has been mitigated largely by federal policy changes and the forecast is close to the trend line of the 2021 IRP.

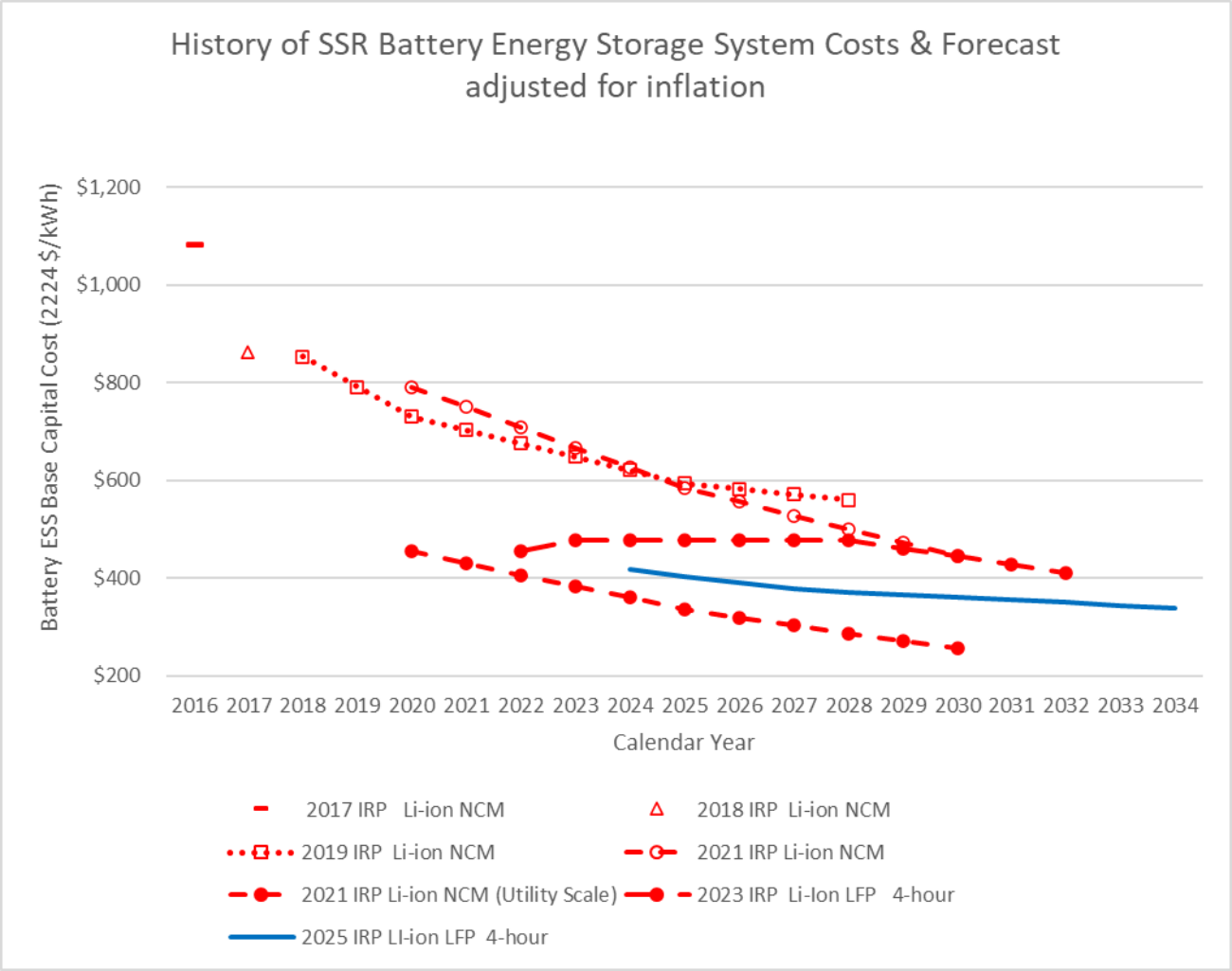
Figure 7.2 – History of Supply-side Resource Wind Costs & Forecast



Energy Storage

Figure 7.3 shows a history of capital cost forecasts used in the supply-side resource table for BESS resources in Utah from 2017 through 2023 IRPs (the red lines). The 2025 IRP capital cost forecast for BESS resources is based on the ATB forecast. The data from IRPs prior to 2021 was based on a 50 MW scale; however, the 50 MW scale is no longer included as a resource option. The solid blue line indicates the 2025 IRP price forecast at the 200 MW scale in Utah. The observed market correction used in the 2023 IRP has been partially mitigated by federal policy changes and the forecast costs are about midway between the less expensive 2021 IRP and the more expensive 2023 IRP.

Figure 7.3 – History of Battery Energy Storage System Costs & Forecast



Utility-scale Energy Storage Resources

PacifiCorp has contracted for the following utility-scale energy storage resources:

- Faraday solar and storage (525 MW solar, 150 MW battery storage with 4-hour duration) is a project supporting customer clean energy goals under Utah Schedule 34.
- Green River solar and storage (400 MW solar, 400 MW battery storage with 4-hour duration) is a project that was originally part of the final shortlist in the 2020 All-Source Request for Proposals. An amendment to the contract expanded the battery from 200 MW with two-hour duration to 400 MW with four-hour duration.
- Dominguez Grid (200 MW battery storage with four-hour duration) is a stand-alone energy storage resource.
- Enterprise/Escalante/Granite Mountain East/Iron Springs storage: each of these contracts is an 80 MW battery storage resource with four-hour duration. Battery storage is being added at existing solar resources and will use surplus interconnection. A surplus interconnection allows for resources to be added at any existing interconnection location so long as the total output to the grid is kept within the existing interconnection capacity.

As a result of the contracts described above, PacifiCorp expects to bring more than one gigawatt of energy storage resources online by the summer of 2026.

Comparison of Lazard's Levelized Cost of Energy Analysis-Version 17 (LCOE+ 17)[41] and NREL's 2024 ATB[42]

Lazard's LCOE+ 17 and the NREL ATB both inform stakeholders about the economic viability of different energy sources, but they differ in scope, methodology, and the specifics of their cost assumptions. Each report is assumed to use a consistent but distinct methodology across all technologies, with technology specific nuances treated fairly. Table 7.14 provides a side-by-side comparison of pertinent information in the two reports.

Lazard's LCOE+ 17 cost assumptions are based on a standardized financial model with fixed debt and equity costs. The analysis assumes 60% debt at an 8% interest rate and 40% equity at a 12% cost, resulting in an after-tax weighted average cost of capital (WACC) of 7.7%.

NREL's ATB offers a range of financial assumption options to reflect different market conditions and provide a more comprehensive view of potential costs.

Table 7.14 – Comparison of Lazard LCOE+ and NREL ATB

	Lazard LCOE+ 17	NREL ATB
Levelized Cost of Energy (LCOE)	Historic Ranges & Averages	Historic and future "Technology Advancement Scenarios" options
Levelized Cost of Storage (LCOS)	Yes	No
Levelized Cost of Hydrogen (LCOH)	Yes	No
Finance Assumptions	No	Yes
Tax Credits	Yes	Optional
Capital Cost	Yes, but not clearly defined	"Capital Expenditure" (CAPEX)
Construction Cost	Assumed to be included	Yes
Overnight Capital Cost	No	Yes
Grid Connection Cost	Not clear	Yes
Construction Finance Factor	No	Yes
Construction Cashflow Curve	No	No
Weighted Average Cost of Capital	Yes	Yes
Fixed O&M (FOM)	Yes	Yes
Variable O&M (VOM)	Yes	Yes
Capacity Factor (CF)	Yes	Yes
Facility Net Power Capacity	Yes	Yes
Heat Rate	Yes	Yes

[41] Lazard Levelized Cost of Energy +, June 2024, https://www.lazard.com/media/xemfey0k/lazards-lcoeplus-june-2024-_vf.pdf
[42] https://atb.nrel.gov/electricity/2024/index

Construction Time	Yes	Yes
Design Life	Yes	Yes
Energy Storage Duration	Yes	Yes
Energy Storage Round Trip Efficiency (RTE)	Yes	Yes
Energy Storage Degradation	Yes	Included in FOM
Regional Resolution Level	Regional markets, including CAISO but not WECC	Select cites in each state, per referenced reports
Regional Adjustment Factors	No	Included in referenced reports
Effective Load Carrying Capability (ELCC) Analysis	Yes	No
Demolition Costs	No	No
Outage Rates, Forced and Planned	Assumed to be included in CF	Assumed to be included in CF
References or Bibliography	No	Yes

The costs reported by Lazard and NREL can differ due to variations in their methodologies and assumptions. Lazard's LCOE+ 17 tends to provide a more standardized comparison across technologies, which can be useful for high-level decision-making. In contrast, NREL's ATB offers a more detailed and nuanced view, considering different scenarios and market conditions.
Reasons for Cost Differences:

- Methodological Differences: Lazard uses a fixed financial model, while NREL incorporates a range of scenarios and assumptions, leading to different cost estimates.
- Scope of Analysis: Lazard focuses on a high-level comparison of technologies, whereas NREL provides detailed data for specific scenarios and market conditions.
- Financial Assumptions: Differences in debt and equity costs, as well as WACC, can lead to variations in the reported costs.
- Technology Assumptions: NREL's ATB includes projections for future technology advancements, which can result in lower cost estimates compared to Lazard's more conservative approach.

In summary, while both Lazard's LCOE+ 17 and NREL's ATB provide valuable insights into the costs of energy technologies, their differences in scope, methodology, and assumptions can lead to varying cost estimates. Understanding these differences is crucial for stakeholders to make informed decisions about energy investments.

Demand-Side Resources

Resource Options and Attributes

Source of Demand-Side Management Resource Data
PacifiCorp conducted a Conservation Potential Assessment (CPA) with for 2025-2044, which provided DSM resource opportunity estimates for the 2025 IRP. The study was conducted by Applied Energy Group (AEG) on behalf of the company. The CPA provided a broad estimate of

the size, type, location and cost of demand-side resources.[43] For the purpose of integrated resource planning, the DSM information from the CPA was converted into supply curves by type of resource (i.e. energy-based energy efficiency and demand response) for modeling against competing supply-side alternatives.

Demand-Side Management Supply Curves

DSM resource supply curves are a compilation of point estimates showing the relationship between the cumulative quantity and cost of resources, providing a representative look at how much of a particular resource can be acquired at a particular price point. Resource modeling utilizing supply curves allows the selection of least-cost resources (e.g., products and quantities) based on each resource's competitiveness against alternative resource options.[44] Due to the timing of the 2025 IRP planning and modeling, PacifiCorp had established, funded and begun acquiring 2025 DSM program acquisition targets. To ensure that the 2025 IRP analysis is consistent with existing and planned demand response and energy efficiency acquisition levels (i.e., Class 1 & 2 DSM), expected DSM savings in each state were fixed for calendar year 2025. In 2026, energy efficiency resources were optimized to reflect ongoing program experience and knowledge of current market conditions and timing challenges, to develop near terms levels of selected acquisition.

As with supply-side resources, the development of DSM supply curves requires specification of quantity, availability, and cost attributes. Attributes specific to DSM curves include:

- Resource quantities available in each year either in terms of megawatts or megawatt-hours, recognizing that some resources may come from stock additions not yet built, and that elective resources cannot all be acquired in the first year of the planning period.
- Persistence of resource savings (e.g., energy efficiency equipment measure lives).
- Seasonal availability and hours available (e.g., irrigation load control programs).
- The hourly shape of the resource (e.g., load shape of the resource).
- Levelized resource costs (e.g., dollars per kilowatt-hour per year for energy efficiency, or dollars per megawatt over the resource's life for demand response resources).

Once developed, DSM supply curves are treated like discrete supply-side resources in the IRP modeling environment.

<u>Demand Response: DSM Capacity Supply Curves</u>

The potential and costs for demand response resources were provided at the state level, with impacts specified separately for summer and winter peak periods. Prior to 2025, PacifiCorp has launched and expanded several demand response programs to acquire resource needs identified in the 2021 IRP update. Several demand response resources characterized as potential demand response resources in the previous IRP are now considered existing or planned demand response resources which will be effective in 2025.

[43] The 2025 Conservation Potential Study is available on PacifiCorp's IRP Support & Studies web page: www.pacificorp.com/energy/integrated-resource-plan/support.html.

[44] Demand-side management modeling and methodology was a frequent topic of discussion in the 2025 IRP public input meeting series and in stakeholder feedback forms.
See Appendix M, stakeholder feedback form #17 (Public Utilities Commission of Oregon).
See Appendix M, stakeholder feedback form #36 (Sierra Club).
See Appendix M, stakeholder feedback form #45 (Utah Clean Energy).

Table 7.15 – Demand Response Existing and Planned Programs

Product	State	Existing or Planned Offering
Res – HVAC DLC	UT	Existing
Res – HVAC DLC	OR, WA	Planned
Res – EV Load Control	OR, WA, UT	Planned
Res – Battery DLC	OR, WA	Planned
Res – Battery DLC	ID, UT	Existing
C&I – Battery DLC	ID, UT	Existing
C&I – Third Party	OR, WA, UT	Existing
C&I – Third Party	ID	Planned
Ag – Irrigation DLC	UT, ID, OR, WA	Existing

Table 7.16 and Table 7.16 show the summary level demand response resource supply curve information, by control area. For additional detail on demand response resource assumptions used to develop these supply curves, see Volume 2 of the 2025 CPA.[45] Potential shown is incremental to the existing DSM resources identified in Table 7.17. For existing program offerings, it is assumed that the PacifiCorp could begin acquiring incremental potential in 2025. For resources representing expanded product offerings, it is assumed PacifiCorp could begin acquiring potential in 2026. New program offerings are assumed to be available in 2026 accounting for the time required for program design, regulatory approval, vendor selection, procurement, and implementation.

Table 7.16 – Demand Response Program Attributes West Control Area,[46]*

Product	Summer		Winter	
	20-Year Potential (MW)	Average Levelized Cost ($/kW-yr)	20-Year Potential (MW)	Average Levelized Cost ($/kW-yr)
Res – EV DLC	15.1	$412	15.1	$412
Res – DLC of Smart Home	0.1	$1,306	0.1	$686
Res – HVAC DLC	17.4	$175	81.7	$73
Res – Pool Pump DLC	0.2	$742	0.1	$1,956
Res – Water Heater DLC	2.7	$134	4.0	$90
Res – Smart Thermostat	40.2	$37	28.9	$29
Res – Grid Interactive Water Heaters	14.6	$97	24.5	$66
Battery DLC	6.1	$31	4.9	$30
C&I – Third Party	8.5	$46	12.4	$54
Ag – Irrigation DLC	1.8	$24	0.0	$0

* Average levelized cost weighted by the 20-year cumulative potential in each state

[45] The CPA can be found at: www.pacificorp.com/energy/integrated-resource-plan/support.html.
[46] Demand response resources derived from the demand response RFP are not included to protect confidential 3rd party pricing information.

Table 7.17 – Demand Response Program Attributes East Control Area,[47]*

Product	Summer		Winter	
	20-Year Potential (MW)	Levelized Cost ($/kW-yr)	20-Year Potential (MW)	Levelized Cost ($/kW-yr)
Res – EV DLC	24.8	$416	24.8	$416
Res – DLC of Smart Home	0.1	$1,601	0.3	$772
Res – HVAC DLC	234.2	$158	141.3	$272
Res – Pool Pump DLC	0.2	$834	0.1	$2,199
Res – Water Heater DLC	12.8	$175	17.5	$117
Res – Smart Thermostat	90.4	$38	50.2	$94
Res – Grid Interactive Water Heaters	1.1	$209	2.0	$139
Battery DLC	65.3	$36	65.2	$41
C&I – Third Party	66.6	$52	72.7	$50
Ag – Irrigation DLC	19.1	$29	0.0	$0

* Average levelized cost weighted by the 20-year cumulative potential in each state

Energy Efficiency DSM, Energy Supply Curves

The 2025 CPA provided the information to fully assess the potential contribution from DSM energy efficiency resources over the IRP planning horizon. The CPA analysis accounts for known changes in building codes, advancing equipment efficiency standards, market transformation, resource cost changes, changes in building characteristics and state-specific resource evaluation considerations (e.g., cost-effectiveness criteria).

DSM energy efficiency resource potential was assessed by state down to the individual measure and building levels (e.g., specific appliances, motors, lighting configurations for residential buildings, and small offices). The CPA provided DSM energy efficiency resource information at the following granularity:

- **State:** Washington, California, Idaho, Utah, Wyoming[48]
- **Measure:**
  - 120 residential measures
  - 146 commercial measures
  - 105 industrial measures
  - 19 irrigation measures

- **Facility type:**[49]
  - 18 residential facility types
  - 28 commercial facility types
  - 30 industrial facility types

[47] Demand response resources derived from the demand response RFP are not included to protect confidential 3rd party pricing information.

[48] Oregon's DSM potential was assessed in a separate study commissioned by the Energy Trust of Oregon.

[49] Facility type includes such attributes as existing or new construction, single or multi-family, and income level for the residential sector. Facility types represent a combination of market segment and vintage and are more fully described in Volume 1 of the 2025 CPA.

- Two irrigation facility type

The 2025 CPA levelized total resource costs over the study period at PacifiCorp's cost of capital, consistent with the treatment of supply-side resources. Costs include measure costs and a state-specific adder for program administrative costs for all states except Utah and Idaho. Consistent with regulatory mandates, Utah and Idaho DSM energy efficiency resource costs were levelized using utility costs instead of total resource costs (i.e., incentive and a state specific adder for program administration costs).

The technical potential for all DSM energy efficiency resources across all states except Oregon over the 20-year CPA planning horizon totaled approximately 15.1 million MWh.[50] The technical potential represents the total universe of possible savings before adjustments for what is likely to be realized (i.e. technical achievable potential). When the achievable assumptions described below are considered the technical potential is reduced to a technical achievable potential for modeling consideration of 12.8 million MWh for all five states. The technical achievable potential for all six states, i.e., including Oregon, for modeling consideration is 17.2 million MWh. The technical achievable potential, representing available potential at all costs, is provided to the IRP model for economic screening relative to supply-side alternatives.

Despite the granularity of DSM energy efficiency resource information available, it was impractical to model the resource supply curves at this level of detail. The combination of measures by building type and state generated just over 50,500 separate permutations or distinct measures that could be modeled using the supply curve methodology. To reduce the resource options for consideration without losing the overall resource quantity available or its relative cost, resources were consolidated into bundles, using ranges of levelized costs and net cost of capacity to reduce the number of combinations to a more manageable number.

Bundle development began with the energy efficiency technical potential identified by the 2021 CPA. To account for the practical limits associated with acquiring all available resources in any given year, the technical potential by measure was adjusted to reflect the amount that is realistically achievable over the 21-year planning horizon. Consistent with the Northwest Power and Conservation Council's achievability assumptions in the 2021 Power Plan as, which typically assume that 85% of the technical potential could be acquired over the 20-year period.[51]

For Oregon, the company does not assess potential for the Energy Trust of Oregon (ETO). Neither PacifiCorp nor the ETO performed an economic screening of measures in the development of the DSM energy efficiency supply curves used in the development of the 2025 IRP, allowing resource opportunities to be economically screened against supply-side alternatives in a consistent manner across PacifiCorp's six states.

Twenty-seven cost bundles, with a separate bundle reserved for home energy reports, were available across six states (including Oregon), which equates to 162 DSM energy efficiency

[50] The identified technical potential represents the cumulative impact of DSM measure installations in the 20th year of the study period for California, Idaho, Washington, Wyoming, and Utah. This may differ from the sum of individual years' incremental impacts due to the introduction of improved codes and standards over the study period. ETO provides PacifiCorp with technical achievable potential.

[51] The Northwest's achievability assumptions include savings realized through improved codes and standards and market transformation, and thus, applying them to identified technical potential represents an aggressive view of what could be achieved through utility DSM programs.

resource supply curves. Table 7.18 shows the 21-year MWh potential for DSM energy efficiency net cost of capacity bundle categorization.

Bundles are classified based on their measure's temperature dependency, as either heating or cooling. A measure is considered temperature dependent if at least 25% of annual kWh savings are derived from temperature dependent end-uses. Measures that have both heating and cooling savings are classified based on whichever has greater volume. Measures that are not temperature dependent, such as lighting, are classified based on whichever season (summer or winter) the measure has a greater capacity contribution. Measures are then ranked based on their net cost of capacity ($/kW-yr) and assigned to a bundle with measures of a similar net cost. There is little need to differentiate bundles that will provide value in nearly all conditions. Measures with a net cost less or equal to zero have energy benefits that exceed their costs, such that their capacity value (reliability benefits) are "free." These measures are assigned to a zero-cost temperature-sensitive bin or a zero-cost non-temperature sensitive bin, which together comprise roughly half of all potential. For non-zero cost measures, roughly equal volumes are distributed among the remaining bundles of heating, cooling, summer, or winter measures. The number of each type of bundle varies by state depending on the potential and load profile used in each state.

Table 7.18 – 2045 Total Cumulative Energy Efficiency Potential by Cost Bundle Category (MWh)

Bundle	California	Idaho	Oregon	Utah	Washington	Wyoming
Cooling Measures	34,469	42,040	609,077	1,282,306	102,772	108,946
Heating Measures	28,535	75,471	870,110	751,888	197,253	122,268
Summer Measures	68,513	119,447	1,292,227	1,244,883	366,577	221,926
Winter Measures	221	14,417	103,548	221,229	3,524	347,464
Zero Cost Temperature Dependent Measures	18,360	84,725	295,605	1,550,447	127,775	84,371
Zero Cost Non-Temperature Dependent Measures	33,056	260,493	1,224,970	3,470,030	376,187	626,797

Cost credits afforded to DSM energy efficiency resources include the following:

- A state-specific transmission and distribution investment deferral cost credit (Table 7.19)
- Stochastic risk reduction credit.[52]
- Northwest Power Act 10-percent credit (Oregon and Washington resources only).[53]

[52] PacifiCorp develops this credit from two sets of production dispatch simulations of a given resource portfolio, and each set has two runs with and without DSM. One simulation is on deterministic basis and another on stochastic basis. Differences in production costs between the two sets of simulations determine the dollar per MWh stochastic risk reduction credit.

[53] The formula for calculating the $/MWh Power Act credit is: (Bundle price - ((First year MWh savings x market value x 10%) + (First year MWh savings x T&D deferral x 10%))/First year MWh savings. The levelized forward electricity price for the Mid-Columbia market is used as the proxy market value.

Table 7.19 – State-specific Transmission and Distribution Credits (2024$)

State	Transmission Deferral Value ($/kW-year)	Distribution Deferral Value ($/kW-year)	Total
California	$5.83	$11.23	$17.06
Oregon	$5.83	$15.65	$21.49
Washington	$5.83	$18.93	$24.76
Idaho	$5.83	$23.11	$28.94
Utah	$5.83	$18.62	$24.46
Wyoming	$5.83	$9.61	$15.44

PacifiCorp relies on simulated load shapes tied to weather stations in PacifiCorp's service territory. Weather is a major driver of PacifiCorp's load and in any given month weather results in a range of high and low load conditions. Weather also impacts the hourly timing of energy efficiency savings particularly for measures that are weather dependent. As in the 2023 IRP, PacifiCorp has reshaped daily energy efficiency volumes to better align with seasonal variations in the load forecast. The highest demand for temperature-sensitive end use loads is expected to occur at the time of the winter and summer peaks in PacifiCorp's service territory. For temperature dependent measures, the simulated savings are proportionate with the temperature-sensitive load across in each month, so that the highest savings occur on the highest load days in the load forecast. To capture the time-varying impacts of energy efficiency resources, each bundle uses an annual 8,760 hourly load shape. These shapes reflect measure-level annual energy savings, differentiated by state, sector, market segment, and end use. These hourly impacts are then aggregated for all measures in each bundle to create a single weighted average load shape for that bundle.

Distribution Efficiency

PacifiCorp continues to develop its CYME CYMDIST® (power flow software) investment in ways that improve engineering response time and, indirectly, distribution system efficiency. In the last biennial period, more than 275 large (Level 2 and Level 3) distributed energy resource (DER) applications were studied in CYME across the Pacific Power and Rocky Mountain Power service areas. This resulted in more than 34 MW (nameplate) of approved private generation across the company. Any energy savings resulting from these approvals across the service territory has not been determined.

These distribution energy efficiency activities were not modeled as potential resources in this IRP.

Transmission Resources

In developing resource portfolios for the 2025 IRP, PacifiCorp included modeling to endogenously select transmission options, in consideration of relevant costs and benefits. These costs are influenced by the type, timing, location, and number of new resources as well as any assumed resource retirements, as applicable, in any given portfolio. Additional information can be found in Chapter 8 (Modeling and Portfolio Evaluation).

Market Purchases

PacifiCorp and other utilities engage in purchases and sales of electricity on an ongoing basis to balance the system and maximize the economic efficiency of power system operations.

Market transactions can encompass a wide variety of product types that can be classified as either forward (entered well in advance of delivery) or spot (entered no more than a day or two before delivery). Currently, the most commonly traded forward products are for heavy load hours (HLH) and/or light load hours (LLH) and are typically for calendar quarters (e.g. "Q3" spanning July, August, and September) or individual months. Other timeframes are less common but could include super-peak products (noon to 8:00 p.m.). All the common forward market products represent undifferentiated system power supplied at a point, but forward transactions can also be based on the costs, availability, options, and/or restrictions of specific physical resources. Some examples include slices of hydropower resources, or a tolling agreement for a natural gas-fired resource.

Examples of spot market transactions include day-ahead HLH and LLH products, day-ahead hourly transactions in the CAISO market, hour-ahead products, and intra-hour products facilitated by the Western Energy Imbalance Market (EIM).

In the next few years, two changes are coming that will change the landscape of markets in both forward and spot timeframes. First, the Western Resource Adequacy Program (WRAP) requires a showing of capacity resources several months in advance of the summer and winter seasons. Current HLH and LLH market products will not count as capacity for WRAP unless the two counterparties agree to a capacity transfer, which may incur a higher cost or reduce a counterparty's willingness to sell. While contracts for physical resources would count as capacity for WRAP if the seller attests the capacity is surplus to its needs and the resource is registered in the program, it is unclear how much capacity of that sort is likely to be available, particularly as many WRAP participants all seek to become compliant. Second, CAISO's Enhanced Day-Ahead Market (EDAM) will expand day-ahead resource optimization beyond the current CAISO footprint and will impact spot market participation. While EDAM takes over much of the optimization function in the day-ahead timeframe, to prevent leaning participants will be required to pass balancing tests to ensure they bring sufficient resources to meet their load, and this may necessitate transactions ahead of the EDAM.

In past IRPs, PacifiCorp included front office transactions (FOT) as proxy resource options, assumed to be firm, that represent procurement activity made on an on-going forward basis to help the company cover short positions. Consistent with the current WRAP rules for unspecified-source purchases, FOTs are not included in the calculation of WRAP compliance in the 2025 IRP, so forward market purchases will not count as capacity. While the 2025 IRP does not allow FOTs to meet WRAP compliance requirements, PacifiCorp expects to continue pursuing economic short-term and intermediate term market opportunities that assist with WRAP compliance and/or balancing.

Spot market purchases and sales also provide opportunities to economically balance loads and resources. The economic opportunities are expected to be enhanced by the EDAM, relative to current operations, but it is unclear how the EDAM will compare to the IRP model's hourly balancing optimization of market purchase and sales volumes against static hourly market prices.

In the EDAM and EIM, market prices are based on marginal supply and demand, so significant increases in supply are likely to reduce prices while increases in demand are likely to increase prices. When demand is high and begins to approach the limits of available supply, economic opportunities will diminish, and adequate capacity will still be needed to participate. The 2025 IRP has incorporated historical relationships between daily prices, loads, and resource supply to better account for the impacts of supply and demand; however, it still relies upon a static forecast of prices that do not account for portfolio selections through time. With these various factors in mind, hourly market purchase volumes have been restricted during key hours on the top five load days within each month. These restrictions apply from 4:00 p.m. to 12:00 a.m. throughout the year, and in the winter an additional restriction applies in the morning, from 4:00 a.m. to 8:00 a.m. Outside of these hours (and all day on lower load days), market purchases are allowed up to modeled transmission limits. Similarly, hourly market sales volumes have been restricted to historical levels, to avoid increasing reliance on wholesale sales at favorable prices that may not persist in an organized market.

Chapter 5 describes the relationship of front office transactions (FOTs) to reliability and WRAP compliance, and FOTs are also considered a resource. Front office transactions can be made years, quarters, or months in advance of use; however, they are generally committed to balance PacifiCorp's system on a balance of month, day-ahead, hour-ahead, or intra-hour basis. The terms, points of delivery, and products vary by individual market point.

Additional discussion of how FOTs are considered in the 2025 IRP, refer to Chapter 5 and Chapter 8.

CHAPTER 8 – MODELING AND PORTFOLIO EVALUATION

CHAPTER HIGHLIGHTS

- The Integrated Resource Plan (IRP) modeling approach is used to assess the comparative cost, risk, and reliability attributes of resource portfolios.
- PacifiCorp used PLEXOS software to produce unique resource portfolios across a range of different planning cases. Informed by the public input process, PacifiCorp identified case assumptions that were used to produce optimized resource portfolios, each one unique regarding the type, timing, location, and number of new resources that could be pursued to serve customers over the next 21 years.[1]
- The PLEXOS long-term (LT) model was used to generate initial portfolios and identify the resulting fixed costs. Each initial portfolio was evaluated for cost and risk among three natural gas price scenarios (low, medium, and high) and three federal carbon dioxide (CO_2) policy scenarios (zero compliance requirements, a high price on CO_2 emissions, and compliance with current Environmental Protection Agency (EPA) CO_2 regulations). An additional CO_2 policy scenario was developed to evaluate performance assuming a price signal that aligns with the social cost of greenhouse gases (SC-GHG). Taken together, there are five distinct price-policy scenarios (medium gas/current EPA regulations, medium gas/zero CO_2, high gas and coal/high CO_2, low gas/zero CO_2, and medium gas/social cost of greenhouse gases).
- Each initial portfolio was also evaluated in the short-term (ST) model to establish system costs over the entire 21-year planning period. The ST model accounts for resource availability and system requirements at an hourly level, producing reliability and resource value outcomes as well as a present-value revenue requirement (PVRR) which serves as the basis for selecting least-cost least-risk portfolios.
- A selection of competitive "variant" portfolios was analyzed using the other four price-policy scenarios in PLEXOS modeling to evaluate how each portfolio performs under differing future market and policy conditions.
- Taking into consideration stakeholder comments and regulatory requirements, PacifiCorp produced additional studies that examine the potential impact of portfolio options on the system.
- Informed by comprehensive modeling, PacifiCorp's preferred portfolio selection process involves evaluating cost and risk metrics reported from ST reporting and stochastic modeling, comparing resource portfolios based on expected costs, low-probability high-cost outcomes, reliability, CO_2 emissions and other criteria.

[1] PacifiCorp's IRP is typically modeled with a 20-year planning horizon, expanded in the 2025 IRP to 21 years to accommodate a specific Washington State requirement extending through 2045. Some discussions and data graphs in the 2025 IRP will refer to the standard 20-year horizon.

Introduction

IRP modeling is used to assess the comparative cost, risk, and reliability attributes of different resource portfolios, each meeting reliability requirements. These portfolio attributes form the basis of an overall quantitative portfolio performance evaluation.

As addressed in public input meetings and stakeholder feedback forms, the subject of modeling for portfolio evaluation is highly technical. PacifiCorp consults regularly with the provider of the PLEXOS optimization modeling software as these methods are developed. Interested parties are encouraged to review publicly available materials (including recordings) from the 2025 IRP public input meeting series for additional context and information.[2]

The first section of this chapter describes the screening and evaluation processes for portfolio selection. Following sections summarize portfolio risk analyses, document key modeling assumptions, and describe how this information is used to select the preferred portfolio. The last section of this chapter describes the cases examined at each modeling and evaluation step. The results of PacifiCorp's modeling and portfolio analysis are summarized in Chapter 9 (Modeling and Portfolio Selection Results).

Key Changes Since the 2023 IRP

The 2025 IRP public meeting inputs series encompassed many key advancements in modeling and evaluation strategy, many driven by stakeholder input. These changes are described in detail later in this chapter. These enhancements are in addition to standard updates applicable to core data such as load and price forecasting. Each change has been incorporated into the company's engagement strategy via public input meetings and stakeholder feedback.[3]

In the 2025 IRP:

- Portfolios must achieve regional and system WRAP compliance.
- Existing thermal units can operate indefinitely with ongoing maintenance.
- IRA Tax Credits are extended through the model horizon (21 years).[4]
- Jurisdictional portfolios are used to integrate final portfolios.
    - States are only able to impact the disposition of resources in which they have an active share.
    - Resource additions are considered situs and must be able to serve requirements in their associated jurisdiction.
- Improved granularity and reliability evaluation.
- No federal CO_2 policy adder is assumed in the expected case.
- Transmission representation now includes a distinct bubble for the Wasatch Front.

[2] For discussion of public materials and feedback, see also Appendix C (Public Input Process), Appendix M (Stakeholder Feedback Forms), and public meeting materials publicly available at https://www.pacificorp.com/energy/integrated-resource-plan/public-input-process.html.

[3] See also Appendix C (Public Input Process), Appendix M (Stakeholder Feedback Forms), and public meeting materials publicly available at https://www.pacificorp.com/energy/integrated-resource-plan/public-input-process.html.

[4] The value of production tax credits (PTCs) is reduced in the last five years of the study horizon, to better represent the value of resource additions in the latter half of the horizon. See Appendix M, stakeholder feedback form #63 (Utah Clean Energy) for additional discussion.

- A new price-policy variation ("MR", medium gas price with at-risk federal regulation) has been added to account for changing expectations for future federal policy.
- No market purchases are allowed in peak hours on the five days with the highest peak load in each month, market purchases are allowed up to transmission limits in all other hours.
- The stochastic analysis incorporates wide-ranging historical volatility in renewable shapes, thermal outages, load, market prices, and hydro availability.

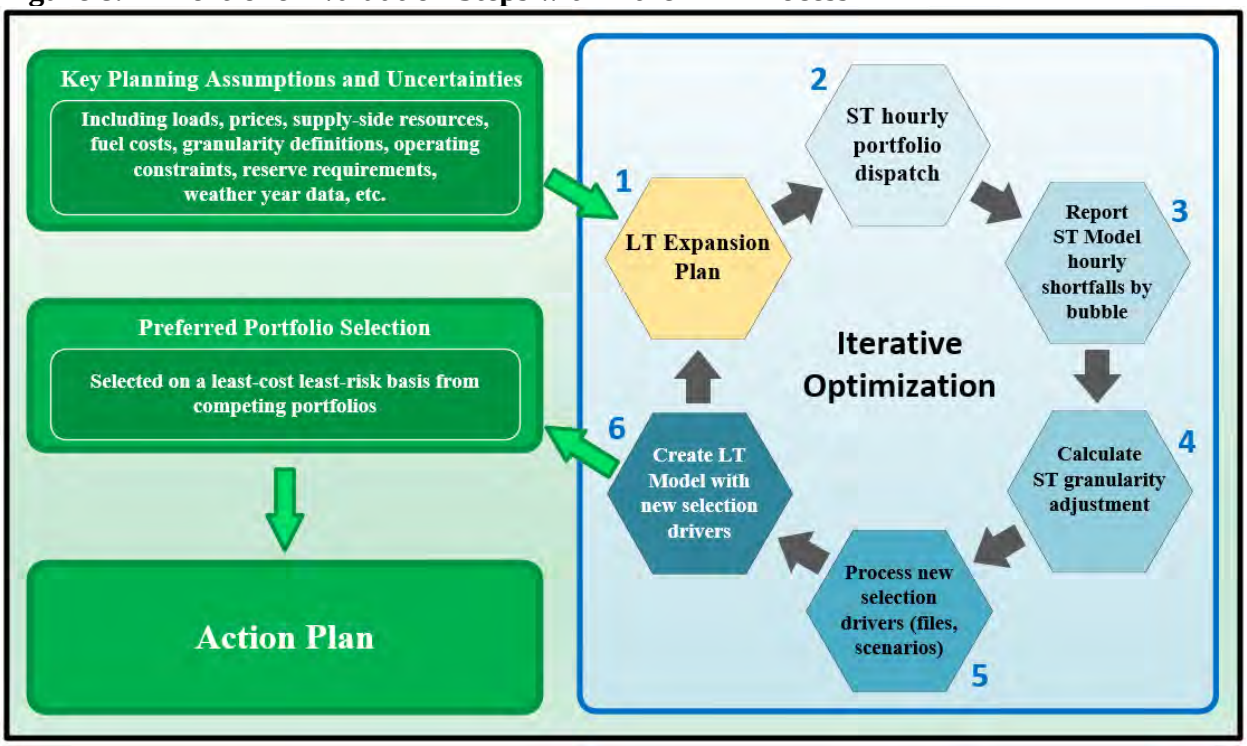
Modeling and Evaluation Steps

All IRP models are configured and loaded with the best available information at the time a model run is produced. Figure 8.1 summarizes the modeling and evaluation steps for the 2025 IRP. The process flow begins at left with the development of key inputs and assumptions. Next, studies are mathematically optimized using PLEXOS software tools[5], as illustrated in the six steps at right ("Iterative Optimization", highlighted in blue). Results are evaluated to determine the least-cost least-risk preferred portfolio from among all eligible portfolios. Finally, the preferred portfolio is used to develop the action plan.[6]

[5] PLEXOS technical modeling assumptions and parameters were discussed in the 2025 IRP public input meeting series and in stakeholder feedback.
See Appendix M, stakeholder feedback form #21 (Renewable Northwest).
See Appendix M, stakeholder feedback form #42 (First Principals Advisory).

[6] The topic of portfolio change was discussed extensively in the 2025 IRP public input meeting series. The modeling and evaluation steps explain how updated inputs are processed – such as updated resource costs as presented in Chapter 7 – resulting in new portfolio outcomes.
See Appendix M, stakeholder feedback form #13 (Joan Entwistle).
See Appendix M, stakeholder feedback form #15 (Sierra Club).
See Appendix M, stakeholder feedback form #27 (Vote Solar).

Figure 8.1 – Portfolio Evaluation Steps within the IRP Process



The portfolio development process in the 2025 IRP is an iterative process, whereby PacifiCorp completes initial LT capacity expansion modeling runs for each portfolio. Portfolios are evaluated for cost, reliability and compliance using the ST model, dispatch focused, modeling results. Data regarding resource value and unserved energy quantities from the ST model is fed back into PLEXOS, and the next phase of iterative portfolio optimization is launched. Each cycle through the six steps is one modeling "phase." Iterations continue until the LT capacity expansion model has produced a portfolio that demonstrates no unserved energy in the ST dispatch model run, and then for several phases thereafter, to identify a range of potentially economic candidate portfolios. Each price-policy scenario and each candidate variant study follows this iterative optimization process. Once a completed portfolio phase achieves reliability, as measured using ST model results, evaluation is completed, and results can be compared to other portfolios.

Overview of Steps in an Iterative Phase

Step 1

For each case, the LT capacity expansion model is run according to the parameters and constraints of the particular study. This results in an expansion plan of selected resources, retirement decisions and transmission option selection. Collectively these selections are called a "portfolio."

Step 2

The LT model expansion plan is fed into the ST model. The ST model performs an hourly dispatch of the portfolio.

Step 3

The ST model reports shortfalls as megawatts of unserved energy. These megawatts must be covered for each location (or "bubble") in the IRP transmission topology. Greater detail regarding use of these reported shortfalls to create the reliability adjustment is below.

Step 4

The granularity adjustment is calculated as the difference in resource value between the ST model results and the LT model results. This calculation gives the mathematical magnitude of the ST model's superior granularity. Greater detail regarding the calculations which comprise the granularity adjustment is below.

Step 5

The reliability shortfalls and granularity adjustments are formatted into data files that can be used in the next phase of the LT model to improve its outcomes.

Step 6

The next phase LT model is built in PLEXOS, if necessary, where shortfalls are represented as an additional load requirement and the granularity adjustment is represented as a cost adjustment (either an increase or decrease in costs) to every resource option.

Granularity Adjustment Detail

The capacity expansion/LT and ST models in PLEXOS each run and solve using a different view of the study horizon. The LT model uses 4 blocks of hours per month over the 21-year horizon. This means the LT model groups similar hours into a block, calculates the average load and resource parameters specific to each block, and then concurrently solves the entire 21-year horizon. In contrast, the ST model concurrently solves (or dispatches) of a given week, or roughly 52 steps per year of 168 hours each, for a specified portfolio of resources as selected in the LT model. When PLEXOS optimizes the system in the 4-block LT view, it calculates a locational marginal price (LMP) specific to each block of hours. The value of a resource in the LT is equal to its generation in each block, multiplied by the LMP during that block specific to its location, and this value is part of the reported results based on the 48 blocks the LT evaluates during each year (4 blocks per month times 12 months). When the ST model dispatches the same resources at an hourly granularity, it calculates the LMP based on hourly conditions, multiplies by a resource's hourly generation, and reports the resulting value for each resource on an annual basis. The ST model also assigns specific resources to hold operating reserves necessary to meet reliability requirements, calculates the marginal price of reserves, and includes this as part of the reported resource value. The mathematical difference between the ST value and the LT value is the granularity adjustment.

The 4 blocks used by the LT model include the top ten percent highest net load hours (load net of wind and solar generation), the highest wind generating hours, the highest solar generating hours, and the remainder of the hours. While these blocks are intended to help the LT model differentiate between key resource types, they can't capture the full range of hourly conditions.

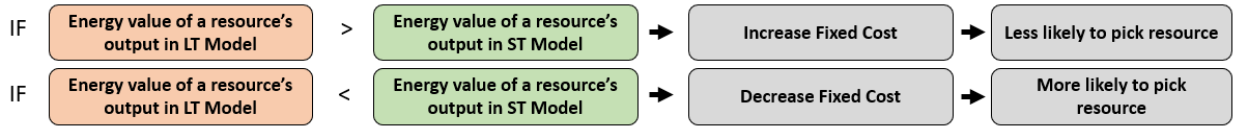
This adjustment, determined independently in step 4 of each phase of portfolio development, is used in the subsequent phase of the process so as to bring the ST model's finer granularity analysis into the LT model, improving the consistency of capacity expansion.

By contrast, in the 2023 IRP, the ST model resource value results were used to inform additional resource selections that were then applied directly in a final run of the ST model. This new iteratively phased approach means that resource selections occur in the LT model using its capacity expansion logic, but with the benefit of the ST model's resource value determinations. Also responsive to stakeholder feedback, a new granularity adjustment is now calculated for every portfolio developed, rather than using one granularity adjustment calculated for each price-policy

scenario. This change, while performance and resource intensive, is responsive to stakeholder concerns regarding the limitations of the prior methodology.

Figure 8.2 illustrates the calculation of the granularity adjustment, which is completely derived from ST and LT model outputs. A distinct granularity adjustment is calculated for every individual resource in each year of every phase of every study.

Figure 8.2 – Granularity Adjustment Determination



This iterative process was conducted for all price-policy scenarios and variant studies. Since each unique granularity adjustment was then fed back into the LT model for the next run, in practice, this means that no two LT model runs have the same granularity adjustment, and each adjustment is wholly dependent upon the performance of resources within that specific portfolio.

Reliability Adjustment Detail

Stakeholders in the 2023 IRP also identified concerns related to the methodology for making reliability adjustments. For the 2025 IRP, in step 3 of each phase, hourly reliability shortfalls are identified by the ST model to be fed back into the LT model to enhance resource selections. As previously noted, the LT model evaluates average conditions during blocks of hours. While this allows the LT model to solve a long horizon in a reasonable time, the average conditions in a block of hours can result in shortfalls in some hours within a block when viewed with hourly granularity. The ST model is able to identify these hours in its evaluation, and these deficiencies are reported by the ST model as hourly shortfalls.

While granularity adjustments are included as an increase or decrease in fixed costs, reliability adjustments are now included as an increase in the load forecast. As with the granularity adjustments, these additions are specific to each study's portfolio. However, unlike the granularity adjustment, the shortfall additions to the load file are cumulatively added to the LT need. ST studies are always run with the base load forecast to verify whether LT additions were sufficient to eliminate shortfalls in all hours.

In order to avoid diluting singular hourly shortfalls across the entirety of a block, the highest monthly shortfall figure is taken, divided by 4 and applied to each hour in the top ten percent of highest net load hour blocks. The highest shortfall in a month is divided by 4 to avoid overshooting the total amount of resources needed. As an example, suppose the phase zero portfolio (the very first iteration of the six steps for a particular study) reports a maximum shortfall of 400 megawatts in Wasatch Front on June 8, 2032, at 8 PM. The 400-megawatt shortfall is divided by 4 to create a 100-megawatt adder to Wasatch Front load. This 100-megawatt adder is added to the base load file for all of the top ten percent net load hours in Wasatch Front in June of 2032, and phase 1 is run with the adjusted load file. If the portfolio selected in phase 1 reports a maximum shortfall of 100 megawatts in Wasatch Front in 2032, the same process is undertaken and 25 megawatts is added to all ten percent top net load hours, such that the load for that block is now 125 megawatts higher than the original phase zero load forecast. Once no shortfalls are reported by the ST model

(a deterministic run using the base load forecast), the adjusted load file used to select a reliable portfolio continues to be applied so that each later phase includes requirements sufficient to induce the LT model to select a portfolio that is reliable. These adjustments are unique to each price policy scenario/variant.

These reliability and granularity adjustments result in an iterative loop from the LT model to the ST model and back to the LT model, with results that evolve over multiple phases. This process leads to a portfolio that is reliable on a deterministic hourly basis. Additionally, ongoing granularity adjustments will lead to diminishing returns on cost reductions. The process is considered complete once portfolios are reliable and the present value revenue requirement (PVRR) of reliable portfolios no longer results in additional cost reductions.

Cost and Risk Analysis

Sufficiently reliable resource portfolios developed by the LT model are simulated through stochastics to produce metrics that support comparative cost and risk analysis among the different resource portfolio alternatives. New to the 2025 IRP, stochastic risk modeling of resource portfolios is performed using actual historical conditions as a guide to volatility and stochastic relationships. These conditions, including weather patterns, thermal outages, fuel and market prices, hydro generation, and wind and solar generation profiles, are mapped to historical dates underlying PacifiCorp's chaotic normal load forecast. PacifiCorp has 18 distinct years of historical data and ran each portfolio using each specific historical year for all years of the 21-year horizon.

The reported stochastic results are based on fifty randomized combinations of the forecasted results based on each historical year. In each of the fifty draws, one historical data year is drawn for each of the years of the IRP study horizon (2025-2045). For example, one draw could include 2025 results based on 2006 weather conditions, 2026 results based on 2015 weather conditions, and 2027 results based on 2020 weather conditions. The same randomized historical year draws are used for all portfolios so that all portfolios can be examined on a comparable stochastic basis. Probabilistic analysis therefore depends upon draws from actual historical variance, which is both more volatile and realistic than prior parameterized variance, improving the verisimilitude of outcomes. The results from these runs are used to calculate a risk adjustment which is combined with ST model system costs to achieve a risk-adjusted PVRR to guide portfolio selection.

Responsive to stakeholder feedback, and like consideration made in past IRPs, cases eligible to become the preferred portfolio which report the possibility of significant end-effects are further evaluated to determine if a portfolio represents significant long-term costs or risks compared to other eligible portfolios.

Portfolio Selection

The portfolio selection process is based on modeling results from the resource portfolio development and cost and risk analysis steps. The screening criteria are based on the PVRR of system costs, assessed across a range of price-policy scenarios on a deterministic basis and on an upper-tail stochastic risk basis. Portfolios are ranked using a risk-adjusted PVRR metric, a metric that combines the deterministic PVRR with upper-tail stochastic risk PVRR. The final selection process considers cost-risk rankings, robustness of performance across pricing scenarios and other supplemental modeling results, including reliability, resource adequacy, and CO_2 emissions data as an indicator of risks associated with greenhouse gas emissions.

Resource Portfolio Development

Resource expansion plan modeling, performed with the LT model, is used to produce resource portfolios with sufficient capacity to achieve reliability over the 21-year study horizon by evaluating groups of hours on an aggregated basis. Each resource portfolio is refined for reliability at an hourly granularity during the reliability assessment step as described above. Each portfolio is uniquely characterized by the type, timing, location, and number of new resources in PacifiCorp's system over time. These resource portfolios reflect a combination of planning assumptions such as resource retirements, CO_2 prices, wholesale power and natural gas prices, load growth net of assumed private generation penetration levels, cost and performance attributes of potential transmission upgrades, and new and existing resource cost and performance data, including assumptions for new supply-side resources and incremental demand-side management (DSM) resources. Changes to these input variables cause changes to the resource mix, which influences system costs and risks.

Long-Term (LT) Capacity Expansion Model

In the 2025 IRP, the LT model is used to establish an initial portfolio under expected conditions (medium gas, zero CO_2), and then modified for each case, based on study parameters, to eliminate shortfalls and maintain reliability. The LT model operates by minimizing operating costs for existing and prospective new resources, subject to system load balance, reliability, and other constraints. Over the 21-year planning horizon, the model optimizes resource additions subject to resource costs and load constraints. These constraints include seasonal loads, operating reserves, and regulation reserves plus a minimum planning reserve margin (PRM)[7] for each load area represented in the model.

The resource portfolios developed using the iterative approach outlined at the beginning of this chapter are appropriately reliable to its granularity and performance limitations. Operating reserve requirements include contingency reserves, which are calculated as 3% of load and 3% of generation. The planning reserve margin in the 2025 IRP is based on compliance with the Western Resource Adequacy Program (WRAP) at each load area in the topology, as provided in Figure 8.3.

If an early retirement of an existing generating resource is assumed or selected for a given planning scenario, the LT model will select additional resources as required to meet loads plus reliability requirement in each period and location. The LT model may also select additional resources that are more economic than an existing generating resource. In the 2025 IRP, the model is simultaneously considering resource additions for reliable and economic system operation both before and after existing generation resources retire, as well as the years in which to retire existing resources.

To accomplish these optimization objectives, the LT model performs a least-cost dispatch for existing and potential planned generation, while considering cost and performance of existing contracts and new DSM alternatives within PacifiCorp's transmission system. Resource dispatch is based on representative data blocks for each of the 12 months of every year. To enhance the ability of the LT model to differentiate key resource types and system conditions, for the 2025

[7] The PLEXOS model uses 'capacity reserve margin' for what PacifiCorp has traditionally described as 'planning reserve margin' ("PRM"). While capacity reserve margin is slightly more precise, PRM is used in the 2023 IRP to reduce confusion over the use of multiple similar terms and because PRM is the industry standard term.

IRP, each month was split into four blocks of hours based on load, wind, and solar, based on wind and solar generation profiles based on weather conditions during the specific days used to develop PacifiCorp's chaotic normal load forecast:

1. The top ten percent highest net load hours. 10% is approximately 70 hours per month, or an average of 2-3 per day, though some days may not have any hours in this group at all.
2. The top ten percent highest wind generation hours on a system basis.
3. The top ten percent highest solar generation hours on a system basis.
4. All other hours

The result of this modeling is to indicate to the LT model that wind and solar have very high availability in some hours, and very low availability in others. This would be expected to contribute to more moderate selections of wind and solar, as they will saturate some periods and have lower value. It would also be expected to contribute to selections of storage and peaking resources, targeted to cover periods in which wind and solar provide little generation supply.

PLEXOS LT model dispatch among blocks of hours in a month is not chronological, so it cannot constrain energy storage charging and discharging, except to ensure that over the course of a month these remain balanced. But within that limitation, PLEXOS determines generation and storage dispatch, optimal electricity flows between zones, and optimal market transactions for system balancing. The model minimizes the system PVRR, which includes the net present value cost of existing contracts, market purchase costs, market sale revenues, generation costs (fuel, fixed and variable operation and maintenance, decommissioning, emissions, unserved energy, and unmet capacity), costs of DSM resources, amortized capital costs for existing coal resources and potential new resources, and costs for potential transmission upgrades.

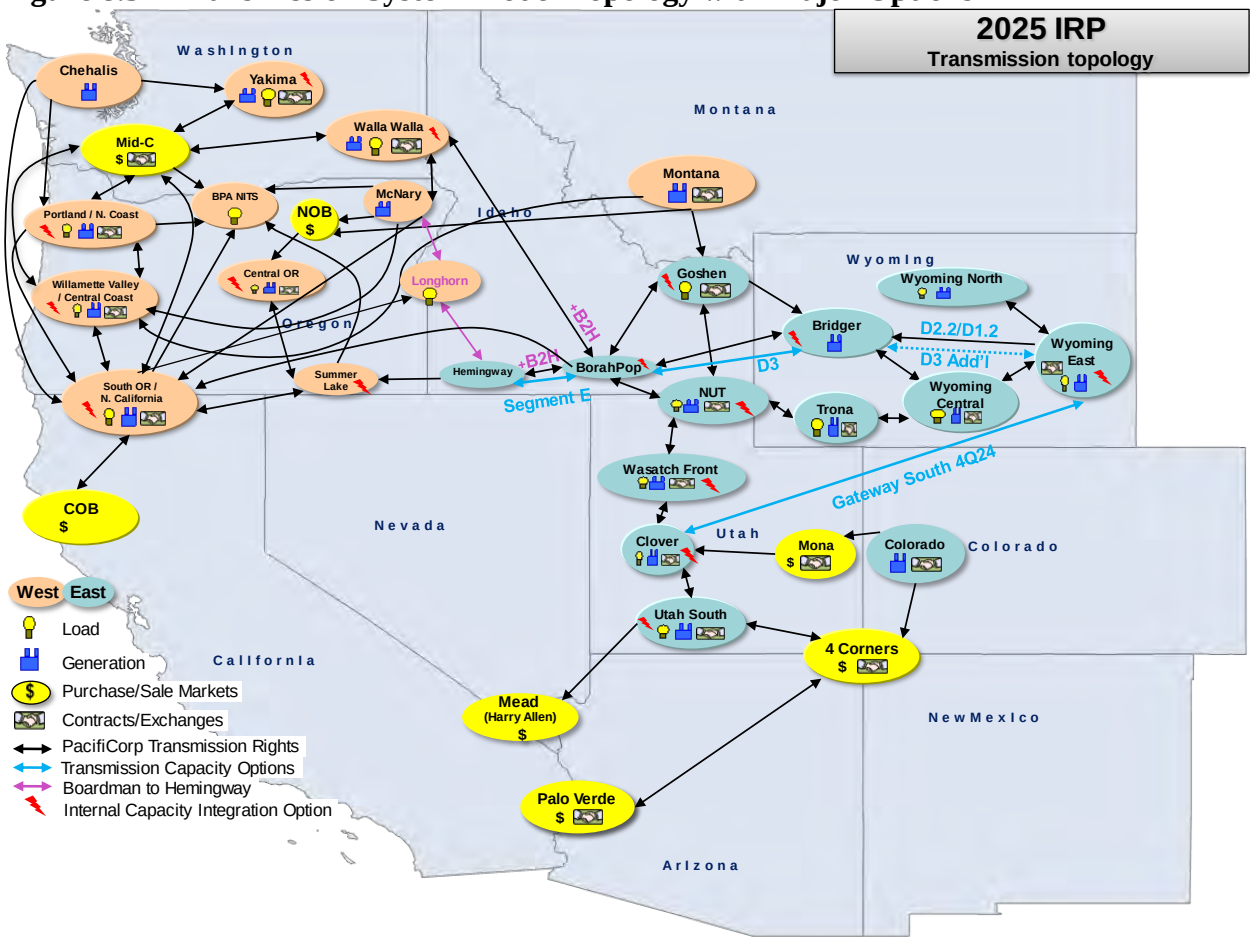
Key modeling elements and inputs for the LT capacity expansion model include the following:

Transmission System

PacifiCorp uses a transmission topology that captures major load centers, generation resources, and market hubs interconnected via firm transmission paths.[8] Transfer capabilities across transmission paths are based upon the firm transmission rights of PacifiCorp's merchant function, including transmission rights from PacifiCorp's transmission function and other regional transmission providers.

[8] Continued interest was expressed on stakeholder feedback regarding the assumption of a Wyoming market hub to represent the opportunity afforded by certain transmission constraints. In light of the restrictions on the types of market products that can count toward WRAP capacity requirements, PacifiCorp's modeling does not count any short-term market products toward WRAP compliance and has limited market purchases at all points during the highest load conditions in each month, to represent potential market liquidity limits. See Appendix M, stakeholder feedback form #39 (Western Resource Advocates).

Figure 8.3 – Transmission System Model Topology with Major Options



This map is for general reference only regarding IRP topology.
PacifiCorp is reevaluating the timing and needs analysis underlying B2H because of factors such as changed native load growth and a lack of capacity available on neighboring transmission systems to deliver to load pockets.

Figure 8.3 illustrates the 2025 IRP modeled topology where each transmission area or "bubble" is defined by any load and generation capability, it's location on the system and its connections to other bubbles.

Transmission Options

In addition to topology, Figure 8.3 illustrates modeled options for endogenous selection by the LT model. Over a span of three public input meetings, PacifiCorp presented information about transmission modeling as it was developed and presented interconnection and Cluster study results used to establish resource and transmission options based on the best available data.[9,10]

"Interconnection" requires modifications, additions, or upgrades to physically and electrically connect a generating facility to the transmission system. Which requirements apply can be

[9] Wildfire mitigation in the context of transmission was discussed in the 2025 IRP public input meeting series and stakeholder feedback. See Appendix M, stakeholder feedback form #18 (Wyoming Office of Consumer Advocate).
[10] Transmission modeling, cluster studies and details of resource-to-transmission relationships were discussed extensively during the 2025 IRP public input meeting series and in stakeholder feedback. See Appendix M, stakeholder feedback form #40 (Renewable Northwest).

impacted by the generation facility type, detailed project specifications, location, prior/existing generation facilities and load.

Studies needed to identify interconnection requirements are interdependent and extensive. Interconnection is carefully regulated for the safety, reliability, and efficiency of the electrical grid. Requests for interconnection made by any project are regulated and managed in various ways, such as:

- **Serial queue:** Signed agreements and near-final serial queue requests.
- **Transition Cluster:** Remaining serial queue requests and 2020 requests.
- **Cluster Study 1:** Spring 2021 requests.
- **Cluster Study 2:** Spring 2022 requests.
- **Cluster Study 3:** Spring 2023 requests
- **Colstrip:** Interconnection to jointly owned Colstrip transmission assets.
- **Surplus:** Interconnection of additional resources at the same point as an existing generator, with aggregate output not exceeding the existing limit.
- **Provisional:** Interconnection study identifies maximum permissible output before transmission upgrades that are not yet in service.
- **Oregon Community Solar:** projects under 3MW seeking to participate in the Oregon Community Solar program.
- ***Informational Studies*:** Informational only, proposal and results are not considered part of later interconnection requests and cannot lead to an interconnection agreement.

The process of evaluating the viability of future projects is complex and time-consuming, resulting in many pending interconnection requests. In 2020, PacifiCorp transitioned from a serial queue study process (one generator at a time) to an annual cluster study process (one study for all new requests in a given area). In the 2023 IRP PacifiCorp significantly enhanced its study of resource and transmission potential to better align with project expectations and costs resulting from these advanced studies. For the 2025 IRP, PacifiCorp has transitioned to using cluster studies to indicate the earliest year a resource type is eligible for selection in any given location (as well as using recent cluster study data as compiled by PacifiCorp Transmission to indicate potential transmission upgrades and costs). Cluster studies are described further in Chapter 4.

Surplus Interconnections

Surplus interconnections add more generation to an existing interconnection without requiring additional transmission lines. However, while installed nameplate capacity is increased at a site, the total megawatt output at any given time at that location cannot exceed the original interconnection capacity.

Added generation can be of the same type and can take the form of additional generating unit or increased generation capability, such as wind repowering resulting in higher nameplate capacity than the existing interconnection. In the event an added resource is of a different type, a hybrid is created. For example, a hybrid resource combination of solar, wind and storage allow a higher net capacity factor among all three resources, increasing overall generation, while avoiding the need for added transmission.

PacifiCorp has submitted surplus interconnection requests to evaluate the addition of solar to several wind resource sites in Wyoming.

Transmission Costs

In developing resource portfolios for the 2025 IRP, PacifiCorp included modeling to endogenously select transmission options, in consideration of relevant costs and benefits. These costs are influenced by the type, timing, location, and number of new resources as well as any assumed resource retirements, as applicable, in any given portfolio.

Resource Adequacy

In its 2025 IRP, PacifiCorp included the monthly planning reserve margin requirements from the Western Resource Adequacy Program (WRAP) in the LT model. The planning reserve margin applies in all periods and must be met by available resources within that area or imports from adjacent areas with excess resources available, subject to transmission constraints. While WRAP is expected to enhance reliability, the monthly capacity contribution values assigned to each resource may not be sufficient to meet hourly requirements in every location, so it does not eliminate the need for reliability assessment. Taken together, these reliability requirements ensure that PacifiCorp has sufficient resources to meet load in all periods, recognizing the uncertainty for load fluctuation and extreme weather conditions, fluctuation of variable generation resources, a possibility for unplanned resource outages, and reliability requirements to carry sufficient contingency and regulating reserves.

Granularity and Reliability Adjustments

As detailed during the 2025 IRP public-input process, the granularity adjustment reflects the difference in economic value in resource options and transmission between an hourly 8760 cost calculation in ST modeling, and the monthly blocking representation used in the LT model.[11]

This adjustment is needed because resources with high variable costs that are rarely dispatched may provide a large value in a few intervals in the ST study, while not dispatching in any of the LT model blocks. Also, storage resources allow for arbitrage among high value and low value hours in each day; however, the block granularity smooths out many of the storage arbitrage opportunities and also doesn't fully capture the effect of storage duration limits.

In parallel with the granularity adjustment, the reliability adjustment addresses unmet capacity needs by hour in the LT model portfolio selection. Much of the peak load hour requirements in mid-afternoon in the summer are adequately met by solar resources. However, resource requirements are driven by portfolio-dependent *net* load peaks (load less renewable resource output), which are harder for the LT model to identify.

While the granularity and reliability adjustments help direct the LT model to more cost-effective resources and a more reliable portfolio, in a single pass, the LT model cannot guarantee reliability at an hourly operational level. Marginal benefits decline as any resource type becomes a larger

[11] See Appendix M, stakeholder feedback form #17 (Public Utilities Commission of Oregon) for responses to questions regarding modeling transmission and granularity adjustments. The method for evaluating granularity value for transmission is the same as for supply-side resources, in that the model reports values used for the granularity adjustments based on the resource's contribution to reducing cost and risk.
See also Appendix M, stakeholder feedback form #36 (Sierra Club).

share of a portfolio, as it saturates the need in the hours it is available. A similar effect occurs with storage, where each incremental MW of system storage capacity must cover a longer duration.

Because of the performance limitations of capacity expansion optimization, the ST model is leveraged to refine the portfolio to achieve a final balanced and reliable mix of resources, as described under the Cost and Risk Analysis section of this analysis, further below.

Thermal Resource Options

Continuing best practice from the 2023 IRP, all majority-owned and operated coal plant sites are considered candidates for surplus interconnection in the 2025 IRP. Other renewable technologies can be added prior to the coal plant's retirement, with the aggregate of the existing and surplus resource output limited to the current maximum output of the coal resource. As a result, the LT model simultaneously evaluates the value of surplus resources both before and after the associated coal units retire, while at the same time evaluating when, or whether, they should retire.

Table 8.1 and Table 8.2 report the coal unit options modeled in the 2025 IRP, whereas Table 8.3 summarizes the options available for natural gas-fired units.

Table 8.1 – Majority-Owned Coal Generator Resource Options[12,13]

Jim Bridger Units 3 and 4	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal 2028 thru 2045	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cofire-2030/2039 111(d)						Dual Fuel	-	-	-	-	-	-	-	-	Gas	-	-	-	-	-	-
Coal-CCS 2030						CCS+45Q												CCS	-	-	-
Dave Johnston 1 and 2	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal 2028-2029/Gas Conv. 2029				-	Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dave Johnston 3	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal 2028				Retired																	
Dave Johnston 4	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal 2028 thru 2045	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cofire-2030/2039 111(d)						Dual Fuel	-	-	-	-	-	-	-	-	Gas	-	-	-	-	-	-
Coal CCS+SCR 2032								CCS+45Q												CCS	-
Wyodak	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal 2028 thru 2045				-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cofire-2030/2039 111(d)						Dual Fuel	-	-	-	-	-	-	-	-	Gas	-	-	-	-	-	-
Coal CCS+SCR 2032								CCS+45Q												CCS	-
Hunter 1-3	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal 2028 thru 2045	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cofire Alt. Fuel-2030/2039 111(d)						Dual Fuel	-	-	-	-	-	-	-	-	Alt. Fuel	-	-	-	-	-	-
Coal CCS+SCR 2032								CCS+45Q												CCS	-
Huntington 1-2	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal 2028 thru 2045	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cofire Alt. Fuel-2030/2039 111(d)						Dual Fuel	-	-	-	-	-	-	-	-	Alt. Fuel	-	-	-	-	-	-
Coal CCS+SCR 2032								CCS+45Q												CCS	-

Key

	Default/current operation	45Q	CCS
	Retirement Option		Alternative Fuel
	Gas conversion option		Assumed retired

[12] While 111(d) compliance can be met with dual fuel operations in 2030-2038, due to engineering uncertainty and modeling complexity, starting in 2030 100% of the fuel input for these options comes from natural gas or alternative fuel. For Hunter and Huntington, which are not located in proximity to natural gas pipeline transport, the alternative fuel modeled in the 2025 IRP is based on the cost of biodiesel, which results in a dispatch price of over $400/MWh (2024$).

[13] After the filing of the 2023 IRP Update on March 31, 2024, a change occurred in the timing of implementation of carbon capture on Jim Bridger Units 3 and 4. CCS assumption for these units is updated for the 2025 IRP. See Appendix M, stakeholder feedback form #5 (Powder River Basin).

Table 8.2 - Minority-Owned Coal Generator Resource Options

Minority-Owned Units	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Colstrip 3		PAC share moves to Unit 4																			
Colstrip 4	*Includes Unit 3 share*																				
Craig 1																					
Craig 2																					
Hayden 1																					
Hayden 2																					

Key: Default/current operation; Assumed retired

Table 8.3 - Natural Gas Generator Resource Options[14]

Chehalis	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Gas-2028 thru 2045	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cofire/non-emitting 2030																					
Currant Creek	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Gas-2028 thru 2045	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hermiston 1/2	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Gas-2028 thru 2039/Alt. Fuel				-	-	-	-	-	-	-	-	-	-	-	-						
Jim Bridger Units 1 and 2	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Gas 2028 thru 2045	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Lakeside 1	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Gas-2028 thru 2045	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Lakeside 2	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Gas-2028 thru 2045	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Naughton Units 1 and 2	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Gas-2026 thru 2045		Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Naughton Unit 3	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Gas-2028 thru 2045	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gadsby Steam 1-3	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Gas 2028 thru 2045	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gadsby CTs 4-6	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Gas 2028 thru 2045	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Key: Default/current operation; Retirement option; Assumed retired; Alternative Fuel; Current (Coal)

New Resource Options

Demand-Side Management

Energy efficiency resources are characterized with supply curves that represent achievable technical potential of the resource by state, by year, and by measures specific to PacifiCorp's service territory. For modeling purposes, these data are aggregated into cost bundles. Each cost bundle of the energy efficiency supply curves specifies the aggregate energy savings profile of all measures included within the cost bundle. Each cost bundle has both a summer and winter capacity contribution based on aggregate energy savings during on-peak hours in July and December aligning with periods where PacifiCorp is most likely to exhibit capacity shortfalls.

Demand response resources, representing direct load control capacity resources, are also characterized with supply curves representing achievable technical potential by state and by year for specific direct load control program categories (i.e., air conditioning, irrigation, and commercial curtailment). Operating characteristics include variables such as total number of hours per year and hours per event that the demand response resource is available.

[14] PacifiCorp has insufficient detail at this time to evaluate alternative fueling options at its Chehalis and Hermiston natural gas-fired facilities, particularly in light of possible impacts on cost-allocation and market participation and has adopted Action Plan item 1h to advance options for potential implementation by 2030.

Wind and Solar Resources

Proxy wind and solar resources available for inclusion in the preferred portfolio are dispatchable by the model up to fixed energy profiles that vary by day and month. The fixed energy profiles for wind and solar resources are based on the weather conditions from the same historical days used to develop the load forecast.

The ability for wind and solar resources to reliably meet demand over time is impacted by the forecasted profiles, along with mix of other resources in the portfolio.

Non-Emitting Resources

Four non-CO_2-emitting thermal resources are considered: nuclear projects, small renewable fuel peaking resources, geothermal resources, and non-emitting hydrogen peaking units leveraging on-site electrolysis with 24 hours of tank storage. Nuclear resources and geothermal are characterized by continuous operation, with the Natrium project combining this operation with storage in the form of heat stored as molten salt. In contrast, peaking resources are designed to run infrequently to support system reliability by dispatching only when needed to meet shortfalls. The small renewable peaking resource for the 2025 IRP is assumed to use biodiesel or renewable diesel, both of which are commercially available. While combustion of these fuels releases CO_2 it is not derived from fossil sources and is eligible to meet compliance requirements in both Oregon and Washington.

Energy Storage Resources

Energy storage resources are distinguished from other resources by the following three attributes:

- Energy take – generation or extraction of energy from a storage reservoir for a specified period.
- Energy return – energy used to fill (or charge) a storage reservoir.
- Storage cycle efficiency – an indicator of the energy loss involved in storing and extracting energy over the course of the take-return cycle.

Modeling energy storage resources requires specification of the size of the storage reservoir, defined in gigawatt-hours. The model dispatches a storage resource to optimize energy used by the resource subject to constraints such as storage-cycle efficiency, the daily balance of take and return energy, and variable costs, if applicable.

Market Purchases

Market purchases are transactions by the company's front office and represent short-term firm agreements for physical delivery of power. PacifiCorp is active in the western wholesale power markets and routinely makes short-term firm market purchases for physical deliveries on a forward basis (i.e., future months or quarters, balance of month, day-ahead, and hour-ahead). These transactions are used to balance PacifiCorp's system as market and system conditions become more certain when the time between an effective transaction date and real time delivery is reduced. Balance of month and day-ahead physical firm market purchases are most routinely acquired through a broker or an exchange, such as the Intercontinental Exchange (ICE). Hour-ahead transactions can also be made through an exchange. For these types of transactions, the broker or

the exchange provides a competitive price. Non-brokered transactions can also be used to make firm market purchases among a wide range of forward delivery periods.

From a modeling perspective, it is not feasible to incorporate all the short-term firm physical power products, differing by delivery pattern and delivery period, which are available through brokers, exchanges, and non-brokered transactions. However, considering that PacifiCorp routinely uses these types of firm transactions, which obligate the seller to back the transaction with reserves when balancing its system, it is important that the contribution of short-term firm market purchases is accounted for in the portfolio-development process.

Capital Costs

Annual capital recovery factors are used to convert capital investment dollars into nominal levelized revenue requirement costs. Use of nominal levelized revenue requirement costs is an established methodology for analyzing capital-intensive resource decisions among resource alternatives that have unequal lives and/or when it is not feasible to capture operating costs and benefits over the entire life of any given resource. To achieve this, the nominal levelized revenue requirement method spreads the return of investment (book depreciation), return on investment (equity and debt), property taxes, income taxes, and demolition costs over the life of the investment. The result is an annuity or annual payment that remains constant such that the PVRR is identical to the PVRR of the nominal requirement when using the same nominal discount rate.

General Assumptions

Study Period and Date Conventions

PacifiCorp executes its 2025 IRP models for a 21-year period beginning January 1, 2025, and ending December 31, 2045. Future IRP resources reflected in model simulations are given an in-service date of January 1st of a given year, except for coal unit natural gas conversions, which are given an in-service date of June 1st of a given year, recognizing the desired need for these alternatives to be available during the summer peak load period after ceasing coal-fired operation at the end of the prior year.

Inflation Rates

The 2025 IRP simulations and cost data reflect PacifiCorp's corporate inflation rate schedule unless otherwise noted. A single annual escalation rate value of 2.18 percent is assumed. This escalation rate reflects the average of annual inflation rate projections for the period 2025 through 2045, using PacifiCorp's September 2024 inflation curve. PacifiCorp's inflation curve is a straight average of forecasts for the Gross Domestic Product inflator and the Consumer Price Index.

Discount Factor

The discount rate used in present-value calculations is based on PacifiCorp's after-tax weighted average cost of capital (WACC). The value used for the 2025 IRP is 6.38 percent. The use of the after-tax WACC complies with the Public Utility Commission of Oregon's IRP guideline 1a, which requires that the after-tax WACC be used to discount all future resource costs.[15] PVRR figures reported in the 2025 IRP are reported in 2024 dollars.

[15] Public Utility Commission of Oregon, Order No. 07-002, Docket No. UM 1056, January 8, 2007.

CO_2 Price Scenarios

PacifiCorp used three different CO_2 price scenarios in the 2025 IRP—zero, high, and a price forecast that aligns with the social cost of greenhouse gases (SCGHG), plus a scenario reflecting compliance with current federal regulations including the currently published EPA rule 111(d). The high greenhouse gas scenario is derived from forecasts of greenhouse gas costs in Washington and California but is applied like a federal obligation throughout the system starting in 2030. Impacts in the scenario which includes current federal regulations also become relevant in 2030, as coal-fired resources must select between retirement, carbon capture, or co-firing by this time.

The SCGHG scenario is in compliance with Washington RCW 19.280.030 including an adjusted cost of greenhouse gas emissions reflecting inflation, defined by the Washington Utilities and Transportation Commission.[16] The social cost of greenhouse gas emissions is assumed to apply in all years of the study horizon. The social cost of greenhouse gases is applied such that the price for the SC-GHG is reflected in market prices and dispatch costs for the purposes of developing each portfolio (i.e., incorporated into capacity expansion optimization modeling). Aligned with Washington staff suggested treatment, system operations also include the SC-GHG once the portfolios are determined, presenting the risk that this operational assumption will not be aligned with actual market forces (i.e., market transactions at the Mid-Columbia market do not reflect the social cost of greenhouse gases and PacifiCorp does not directly incur emission costs at the price assumed for the social cost of greenhouse gases).

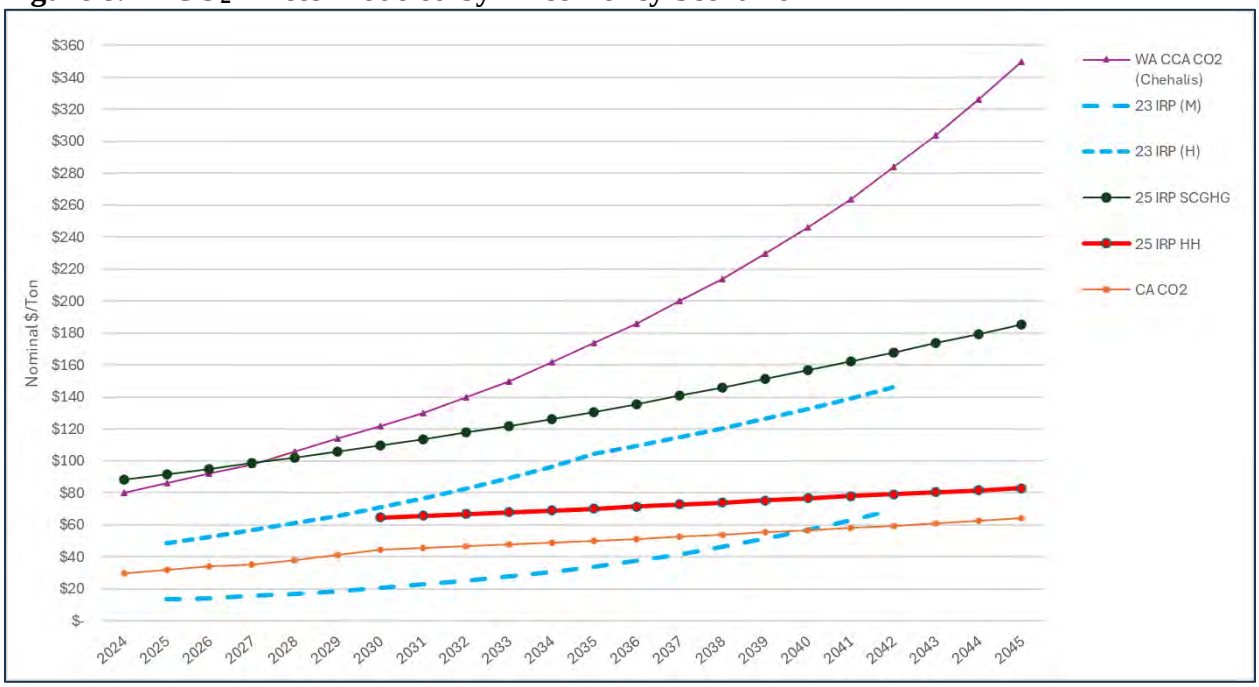
In all scenarios, emissions from the Chehalis natural gas plant incur the forecasted cost of allowances under the cap-and-invest program established in the Climate Commitment Act passed by the Washington Legislature in 2021.[17] This is in addition to the assumed federal CO_2 policy represented in the zero, high, and social cost of greenhouse gas scenarios described above. The modeled allowance cost is based on the allowance cost cap identified by the Washington Department of Ecology and starts at $88 metric ton in 2024.[18]

[16] Washington Utilities and Transportation Commission, Order 05, Docket No. U-190730, July 25, 2024. Available online at: https://apiproxy.utc.wa.gov/cases/GetDocument?docID=27&year=2019&docketNumber=190730 (Accessed 11/8/2024).

[17] Stakeholder feedback requested modeling Chehalis without consideration of Washington's Climate Commitment Act. Notwithstanding that certain commissions have declined to allow the company to recover these costs, the company continues to incur these costs, which are therefore modeled. See Appendix M, stakeholder feedback form #19 (Wyoming Office of Consumer Advocate).

[18] Washington Cap-and-Invest Program 2024 Annual Allowance Price Containment Reserve Tier Price and Price Ceiling Unit Price Notice. December 2023. Available online at: https://apps.ecology.wa.gov/publications/documents/2302066.pdf (Accessed 11/8/2024).

Figure 8.4 – CO_2 Prices Modeled by Price-Policy Scenario



Wholesale Electricity and Natural Gas Forward Prices

For 2025 IRP modeling purposes, five electricity price forecasts were used: the official forward price curve (OFPC) and four scenarios. Unlike scenarios, which are alternative spot price forecasts, the OFPC represents PacifiCorp's official quarterly outlook. The OFPC is compiled using market forwards, followed by a market-to-fundamentals blending period that transitions to a pure fundamentals-based forecast.

At the time PacifiCorp's 2025 IRP modeling inputs were prepared, the September 2024 OFPC was the most current OFPC available. For both gas and electricity, starting with the prompt month, the front 36 months of the OFPC reflects market forwards at the close of a given trading day.[19] As such, these 36 months are market forwards as of September 2024. The blending period (months 37 through 48) is calculated by averaging the month-on-month market forward from the prior year with the month-on-month fundamentals-based price from the subsequent year. The fundamentals portion of the natural gas OFPC reflects an expert third-party price forecast. The fundamentals portion of the electricity OFPC reflects prices as forecast by AURORAxmp[20] (Aurora), a WECC-wide market model. Aurora uses the expert third-party natural gas price forecast to produce a consistent electricity price forecast for market hubs in which PacifiCorp participates. PacifiCorp updates its natural gas price forecasts each quarter for the OFPC and, as a corollary, the electricity OFPC is also updated.

Scenarios using high or low gas prices do not incorporate any market forwards since scenarios are designed to reflect an alternative view to that of the market. As such, the low and high natural gas price scenarios are purely fundamental forecasts. Low and high natural gas price scenarios are also

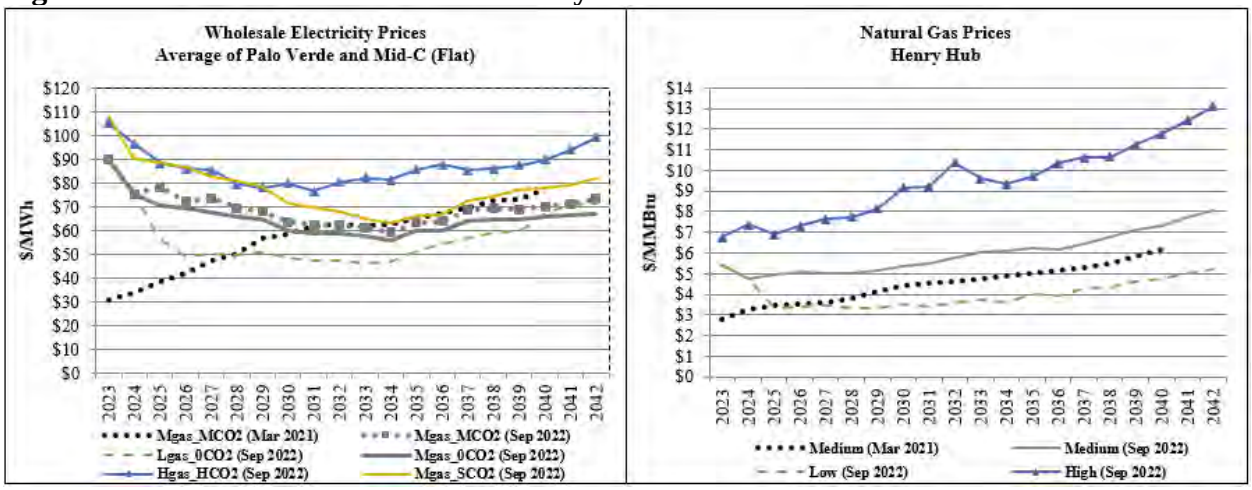
[19] The September 2024 OFPC prompt month is November 2024; October 2024 would be traded as "balance of month" when the OFPC is released.
[20] AURORAxmp is a proprietary production cost simulation model, developed by Energy Exemplar, LLC.

derived from an expert third-party forecast. Similarly, the SCGHG scenario does not incorporate any market forwards since that greenhouse gas policy represents an alternative view that applies throughout the study period.

New to the 2025 IRP, in response to stakeholder feedback and requests related to volatility in coal pricing, the high gas and market price-policy scenario also includes an elevated coal fuel supply cost. This represents risks such as supply-chain issues as well as the potential for increased transportation costs or other increased variable coal costs which are not present in the base forecast for coal pricing.[21] The increased cost calculated for coal pricing was developed by evaluating the percentage difference in the average annual gas prices at Henry Hub between the medium and high cases. Annual percentage differences were then applied to each coal plant's coal supply price over the 21-year horizon.

Figure 8.5 summarizes the five wholesale electricity price forecasts and three natural gas price forecasts used in the base and scenario cases for the 2025 IRP.

Figure 8.5 – Nominal Wholesale Electricity and Natural Gas Price Scenarios



Cost and Risk Analysis

Short-Term (ST) Schedule Model

The ST model uses the same common input assumptions described for the LT model coupled with the portfolio selected by the LT model. LT results provide the initial capacity expansion plan for the ST model to dispatch.

[21] Coal supply, costs and risks were discussed in the 2025 IRP public input meeting series and stakeholder feedback. In the 2025 IRP, PacifiCorp considers base coal cost assumptions, the Jim Bridger Long-term Fuel Plan sensitivity, and coal-related variant studies. For stakeholder feedback and responses:
See Appendix M, stakeholder feedback form #28 (Utah Citizens Advocating Renewable Energy).
See Appendix M, stakeholder feedback form #29 (Utah Clean Energy).
See Appendix M, stakeholder feedback form #30 (Katie Pappas).
See Appendix M, stakeholder feedback form #31 (Jane Myers).
See Appendix M, stakeholder feedback form #32 (Sara Kenney).

Reliability Assessment and System Cost

The ST model begins with a portfolio from the LT model that has not yet been refined to reflect the reliability and compliance needs of a particular study (e.g., a particular sensitivity or price-policy scenario). The ST model is first run at an hourly level for 21 years in order to retrieve two critical pieces of data: 1) shortfalls by hour, and 2) the value of every potential resource to the system that is specific to the portfolio itself, and the other input assumptions, such as the price-policy scenario.

As discussed at the start of the chapter, these data points are fed back into the LT model to prompt endogenous selections of resources that lead to a reliable portfolio.

Resource Value

PLEXOS calculates a locational marginal price (LMP) specific to each area in each hour that is based on supply and demand in that area and available imports and exports on transmission links to adjacent areas. This is also known as a shadow price. PLEXOS also calculates the marginal price specific to ancillary services (i.e., operating reserves) in each hour. PLEXOS then multiplies these prices by a resource's optimized energy and operating reserve provision for each hour and reports the total as a resource's estimated revenue. In an organized market, this would represent the expected payments based on market-clearing prices.

When variable costs (such as fuel, emissions, and VOM) are subtracted out, the result is a resource's "net revenue". Net revenue provides a clear model-optimized assessment of every resource's value to the system, which is then used to assess resource additions needed to preserve reliable operation of the system.

While the net revenue approach is demonstrably superior to past resource value measures, especially as it is evaluated simultaneously for all potential resources, modeling capabilities, net revenue has limitations that should be acknowledged. Net revenue represents the value of the last MW of capacity from a given resource – as resources grow larger, the average value from the first MW of capacity to the last MW of capacity will tend to be somewhat higher than the reported marginal value. Conversely, adding more of a particular resource will result in declining values. While marginal prices will be very high in hours with supply shortfalls, this only indirectly contributes to reliable operation by helping to identify beneficial replacement resources. Once sufficient resources are added, shortfalls will mostly be eliminated, and marginal prices will again reflect the variable cost of an available resource.

Portfolio Refinements

While many resource options are evaluated, utility scale generation resources are mostly restricted to two circumstances: surplus or replacement resources at generators that are eligible to retire, and new resources at locations with interconnection or transmission upgrade options. New for the 2025 IRP, small resources (those with a capacity of fewer than 20 megawatts) are eligible to be sited within any of the load regions and unconstrained by new transmission requirements, as PacifiCorp's studies have shown resources that are sufficiently small and sized consistent with the local grid can be feasible without large transmission investments. Like small resources, PacifiCorp has added a "local" battery option within each of the load areas which is available for selection at a higher cost than those co-located with other resources (per the supply-side resource table). In initial jurisdictional runs, small generator and local battery resources are limited based on the load in each transmission bubble, due to the assumption these are sized to serve local load so as not to require transmission investment.

These interconnection and transmission upgrade options are limited and can be expensive. Replacing existing thermal generators with resources that provide only a portion of their interconnection capacity in "firm" capacity creates a need for additional interconnection capacity elsewhere, and a key strategy is maximizing the "firmness" of each MW of interconnection capacity to provide greater value. Within a transmission constraint, batteries are assumed to always be co-located with other resources, enabling them to shift energy accumulated during periods of high solar radiance, wind speed or other generation, and increase the effective capacity contribution of the combination of resources in a given location.

Portfolio Cost

Each run of the ST model produces an optimized dispatch of a portfolio to reflect least-cost operations while meeting all requirements and adhering to modeled constraints. The ST model's hourly granularity means that this system cost will be highly accurate, taking into account operational nuances that are obscured in the less granular LT model. This in turn means that when evaluating the constellation of all competitive portfolios, the comparison will be based on appropriate relationships among all system components to yield an accurate PVRR.

Additional Measures

- Annual energy not served (ENS)
- Annual CO_2 emissions.

Stochastic Modeling

Once unique resource portfolios are developed using the LT and ST models, additional modeling is performed to produce metrics that support comparative cost and risk analysis among the different resource portfolio alternatives. For the 2025 IRP, stochastic risk modeling of resource portfolio alternatives is performed with the ST model.

The standard ST model inputs reflect a normalized view of future conditions and the typical range of outcomes across each month. For stochastic modeling in the 2025 IRP, alternative inputs are used that reflect conditions analogous to actual results in a specific historical year. Stochastic

inputs for the 2025 IRP have been expanded and now include wind and solar generation profiles, along with the energy efficiency profiles for weather-sensitive bundles, in addition to the variables reflected in past IRPs: load, wholesale electricity and natural gas prices, hydro generation, and thermal unit outages.

Appendix H (Stochastics) discusses the methodology for developing the stochastic inputs for the 2025 IRP.

Stochastic Conditions

For the 2025 IRP, PacifiCorp has data reflecting eighteen discrete annual conditions, specifically the historical data and variances from 2006-2023 for each of the stochastic inputs. By running eighteen ST model scenarios covering each of these conditions, results can encompass the full range of conditions. However, each of these ST model scenarios represents conditions from a single year repeating in every year of the study horizon, with slight differences from year to year to account for days of the week, plus load growth, climate change impacts on load and hydro, and changes in the resource portfolio. For instance, using historical data based on 2015, every year from 2025-2045 would be a dry hydro year (below average). There are benefits to compiling the results in this way, as it will be easier to identify specific historical weather conditions that are leading to high costs and ENS. But to produce portfolio performance measures, random sampling of the annual results may be appropriate, particularly for assessment of multi-year compliance requirements such as renewable portfolio standards (RPS) and Washington's Clean Energy Transformation Act (CETA).

Stochastic Portfolio Performance Measures

Stochastic simulation results for each unique resource portfolio are summarized, enabling direct comparison among resource portfolio results during the preferred portfolio selection process. The cost and risk stochastic measures reported from the Monte Carlo annual draws include:

- Stochastic mean PVRR
- 5^{th}, 90^{th} and 95^{th} percentile PVRR
- Standard deviation
- Risk-adjustment
- Energy Not Served (ENS)

Stochastic Mean PVRR

The stochastic mean PVRR is the average of system net variable operating costs among 20 iterations, combined with the nominal levelized capital costs and fixed costs corresponding to the LT model for any given resource portfolio. The net variable cost from stochastic simulations, expressed as a net present value, includes system costs for fuel, variable O&M, long-term contracts, system balancing market purchase expenses and sales revenues, reserve deficiency costs, and ENS costs applicable when available resources fall short of load obligations. Capital costs for new and existing resources are calculated on a nominal-levelized basis. Other components in the stochastic mean PVRR include CO_2 emission costs for any scenarios that include a CO_2 price assumption. The stochastic mean PVRR, is not used directly in portfolio selection; instead, the more granular ST PVRR serves as the base measure of net system cost, modified appropriately by stochastic risk.
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5th and 95th Percentile PVRR

The 5th and 95th percentile PVRRs are also reported from the 18 results drawn from the ST runs under 18 distinct stochastic conditions. These measures capture the extent of upper-tail (high cost) and lower-tail (low cost) stochastic outcomes. As described above, the 95th percentile PVRR is used to derive the high-end cost risk premium for the risk-adjusted mean PVRR measure. The 5th percentile PVRR is reported for informational purposes.

Production Cost Standard Deviation

To capture production cost volatility risk, PacifiCorp uses the standard deviation of the stochastic production cost from the 50 random draws of the 18 runs under stochastic conditions. The production cost is expressed as a net present value of annual costs over the IRP horizon. This measure meets Oregon IRP guidelines to report a stochastic measure that addresses the variability of costs in addition to a measure addressing the severity of bad outcomes.

Risk-Adjustment

The model outcomes of the 50 random draws are used to calculate a risk-adjustment measuring the relative risk of low-probability, high-cost outcomes. This measure is calculated as five percent of system variable costs from the 95th percentile. This metric expresses a low-probability portfolio cost outcome as a risk premium based on 20 random draws for each resource portfolio and applied to the hourly-granularity deterministic PVRR. The rationale behind the risk-adjusted PVRR is to have a consolidated cost indicator for portfolio ranking, combining the most precise available system cost and high-end cost-risk concepts.

Energy Not Served (ENS)

In past IRPs, the use of the reduced granularity in the PLEXOS MT model limited the relevance of the reported ENS. In the 2025 IRP, the ST model's full 8760 granularity is being reflected in stochastic analysis, so reported ENS is representative of a portfolio's performance in the real-world historical conditions that underlie the stochastic inputs.

Forward Price Curve Scenarios

Preferred portfolio variants developed during the portfolio-development process are analyzed under up to five price-policy scenarios.

Other PLEXOS Modeling Methods and Assumptions

Transmission System

The base transmission topology shown in Figure 8.3 is used in each of the PLEXOS models. Any transmission upgrades selected by LT and ST model processes that provide incremental transfer capability among bubbles in this topology are part of the portfolio and thus included in normalized and stochastic ST optimizations.

Resource Adequacy

The reality of modeling large complex power systems in a world of significant variable resources is that availability must be compared to requirements in all modeled periods, as measurements only at peak do not adequately establish system reliability. For the 2025 IRP, PRM and resource contributions based on WRAP are used as part of portfolio selection, but this is not part of resource dispatch. In addition to WRAP compliance, ST reliability modifications to the portfolio evaluate hourly resource availability and system requirements to directly determine reliability shortfalls and any additional resource need at the hourly level.

Energy Storage Resources

Storage resources have many potential advantages, including storage for frequency regulation, grid stabilization, transmission loss reduction, reduced transmission congestion, renewable energy smoothing, spinning reserve, peak-shaving, load-levelling, transmission and distribution deferral, and asset utilization.

Each PLEXOS model dispatches storage resources endogenously, subject to any applicable constraints, for example requirements to charge from onsite solar or for the combined solar and storage output and reserves to remain within a single interconnection limit. The model can deploy energy storage for the most cost-effective uses, including any combination of load ramping and leveling, reserve carrying, and to complement the benefits of renewable resource additions, particularly co-located renewables.

Other Cost and Risk Considerations

In addition to reviewing the risk-adjustment, ENS, and CO_2 emissions data, PacifiCorp considers other cost and risk metrics in its comparative analysis of resource portfolios. These metrics include fuel source diversity, and customer rate impacts.

Fuel Source Diversity
PacifiCorp considers relative differences in resource mix among portfolios by comparing the capacity of new resources in portfolios by resource type, differentiated by fuel source. PacifiCorp also provides a summary of fuel source diversity differences among top performing portfolios based on forecasted generation levels of new resources in the portfolio. Generation share is reported among thermal resources, renewable resources, storage resources, DSM resources and market purchases.

Customer Rate Impacts
To derive a rate impact measure, PacifiCorp computes the change in nominal annual revenue requirement from top performing resource portfolios (with lowest risk adjusted mean PVRRs) relative to a benchmark portfolio selected during the final preferred portfolio screening process. Annual revenue requirement for these portfolios is based on the risk adjusted PVRR results from the models and capital costs on a nominal levelized basis. While this approach provides a reasonable representation of relative differences in projected total system revenue requirement among portfolios, it is not a prediction of future revenue requirement for rate-making purposes.

Market Reliance
To assess market reliance risk, PacifiCorp quantifies market purchases for each portfolio allowing comparisons among cases in Chapter 9 (Modeling and Portfolio Selection Results). Starting in the

2021 IRP, market purchases were restricted compared to past IRPs, as described in Chapter 7 (Resource Options).

Portfolio Selection

Portfolios are measured for relative performance regarding system costs, risk-adjusted system costs, ENS, CO_2 emissions, and compliance with state and federal policies. The risk-adjusted PVRR accounts for relative risk of volatility among portfolios.

Each portfolio under examination at a given step in the analysis is compared based on cost-risk metrics, and the least-cost, least-risk portfolio is chosen. Risk metrics examined include stochastic PVRR, risk-adjusted PVRR, ENS and emissions. As noted above, market reliance risk was also evaluated. The comparisons of outcomes are detailed, ranked, and assessed in the next chapter.

Additional quantitative analysis can be performed to further assess the relative differences among top-performing portfolios; qualitative analysis can also be considered where appropriate during portfolio selection on the basis of known factors that could not be readily captured in models.

Final Evaluation and Preferred Portfolio Selection

Due to the lengthy nature of the IRP cycle, the final step is the last opportunity to consider whether top-performing portfolios merit additional study based on observations in the model results across all studies, additional sensitivities, possible updates driven by recent events, and additional stakeholder feedback. Additional sensitivities may refine the portfolio selection based on portfolio optimization and cost and risk analysis steps.

During the final screening process, the results of any further resource portfolio developments will be ranked by risk-adjusted PVRR, the primary metric used to identify top performing portfolios. Portfolio rankings are reported for the five price-policy price curve scenarios. Resource portfolios with the lowest risk-adjusted PVRR receive the highest rank. Final screening also considers system cost PVRR data from the PLEXOS models and other comparative portfolio analysis. At this stage, PacifiCorp reviews additional metrics from the models looking to identify if ENS and CO_2 emissions results can be used to differentiate portfolios that might be closely ranked on a risk-adjusted PVRR basis.

Case Definitions

Case definitions specify a combination of planning assumptions used to develop each unique resource portfolio analyzed in the 2025 IRP, organized here into major development categories:

- Initial Portfolios, including all variants
    - Initial portfolios and variants are evaluated under three distinct sets of jurisdictional requirements:
        - Utah/Idaho/Wyoming/California.
        - Oregon.
        - Washington.

    - Integrated Portfolios incorporate selections from the top performing initial portfolios under each set of jurisdictional requirements.
    - The preferred portfolio is selected based on the integrated portfolio results.
- Jurisdictional Analysis
- Sensitivity Cases

Additional portfolio detail can be found in Appendix I (Capacity Expansion Results).

Initial Portfolios

Informed by the public-input process, the initial cases explore significant interactions among retirement options including the potential to convert coal units to natural gas or biodiesel operations, install carbon-capture equipment on coal-fired facilities, and retire units during the study horizon. The modeling continues to include a wide range of transmission options for selection, assessed simultaneously with all other competing elements. The initial portfolios also consider how resource selections change with price-policy assumptions that deviate from the medium natural gas price and zero CO_2 price assumptions used to develop many resource portfolios. All the initial portfolios rely on the combined capabilities of the optimization models within PLEXOS.

Jurisdictional Definitions and Modeling

As discussed above, distinct requirements exist for various jurisdictions, and some of these requires conflict. As a result, initial portfolio modeling is used to separate the requirements as described below, allowing for the development of optimal portfolios of resources to meet jurisdictional needs.

Compared to Oregon and Washington, modeling for Utah/Idaho/Wyoming/California (UIWC) is more focused on least-cost resource selection regardless of fuel type. UIWC resources must meet the Western Resource Adequacy Program (WRAP) requirements for this jurisdiction. As a result, the only modeling constraint for this jurisdiction is one which combines load and requires the model to select enough total resources (including existing resources under current allocation protocols) to meet WRAP planning requirements. All resources are eligible for inclusion in these states and this requirement.

All Washington resource selections are analyzed and optimized assuming the SCGHG price-policy scenario, as required under RCW 19.280.030 for clean energy planning.

Oregon initial portfolios model compliance with House Bill 2021. Oregon participates in existing coal-fired resources through 2029 and existing gas-fired resources (including the gas conversions of Naughton 1 and 2 in 2026 and the endogenously selected conversion of Dave Johnston Units 3 and 4 in 2029) through 2039. Emissions allocated to Oregon from existing resources are calculated based on Oregon's current share of the resources and the appropriate Oregon DEQ emissions factors. Like other jurisdictions, Oregon must be WRAP compliant. PLEXOS models face challenges meeting annual emissions constraints due to the need to model slices of time in each different model (as described earlier in this chapter). This has been addressed by assessing a

shadow price on Oregon allocated emissions as a model driver to ensure HB 2021 compliance is achieved. The shadow price is not reported from the model as a cost to customers, but is instead used to impose a penalty on the model if Oregon allocated resources emit CO_2-E. This price drives the model to reduce emissions (and generation) and select additional resources to meet Oregon load. Compliance for Oregon is measured by determining whether there is enough Oregon-allocated generation to meet Oregon load on an annual basis while also having emissions below the Oregon required thresholds.

Five price-policy scenarios were evaluated in this IRP:

- MN: Medium natural gas/No federal CO_2regulations
- MR: Medium natural gas/current federal CO_2 regulations under Section 111 of the Clean Air Act.
- LN: Low natural gas/No federal CO_2 regulations.
- HH: High natural gas/High CO_2 cost applied to all generators (updated CO_2 forecast, starting 2030) with no other federal CO_2 regulations.
- SC: Medium natural gas/Social cost of greenhouse gases (starting immediately) from Washington docket U-190730 with no other federal CO_2 regulations.

Table 8.4 provides the price-policy case definitions for the 2025 IRP. Additional information, including coal unit retirement assumptions, are provided for each case in Appendix I (Capacity Expansion Results).

Table 8.4 – Price-Policy Case Definitions

Price-Policy	Existing Coal[(b)]	Existing Gas[(b)]	Other Existing Resources	Proxy Resources[(c)]
MN	Optimized	Optimized	End of Life	All allowed
MR	Optimized	Optimized	End of Life	All allowed
LN	Optimized	Optimized	End of Life	All allowed
HH	Optimized	Optimized	End of Life	All allowed
SC	Optimized	Optimized	End of Life	All allowed

(a) Thermal coal and gas resources are endogenously optimized for retirements, conversions and technology installations.
(b) Optimized proxy portfolio selections include renewables, offshore wind, storage, natural gas, transmission, DSM, purchases and sales, etc.

In all five price-policy scenarios, emissions from the Chehalis natural gas plant incur the forecasted cost of allowances under the cap-and-invest program established in the Climate Commitment Act passed by the Washington Legislature in 2021. This cost is incremental to the CO_2 cost included in each price-policy scenario. Where applicable, the price-policy scenarios above represent CO_2 as a cost applicable to all emitting resources, based on the direct emissions associated with the fuel consumed by each generator.

The 2023 IRP included a medium natural gas/medium CO_2 (MM) price-policy scenario. The MM price-policy scenario, which was the price-policy included in the 2023 IRP preferred portfolio, was excluded from the 2025 IRP. In the 2023 IRP, the MM price-policy was included as a proxy to represent potential future federal CO_2 regulations. For the 2025 IRP the MR price-policy scenario, which was not included in the 2023 IRP, encompasses federal CO_2 regulations. This

price-policy scenario was added in response to the final CO_2 regulations issued by EPA on April 25, 2024, which apply to new natural gas-fired combustion turbines and existing coal, oil, and gas-fired steam turbines.

All portfolios consider variations in retirement timing, the impact of regional haze compliance operating limits and options for gas conversion or CCS retrofit for certain units. The initial portfolios differ based on planning assumptions around coal unit retirement options and retirement timing.

Certain additional cases were developed based on stakeholder feedback and state requirements to evaluate the impacts of specific future scenarios. These cases are all eligible to be adopted into the preferred portfolio if the analysis warrants their inclusion. In the 2025 IRP, there are the following variant portfolio selection cases as shown in Table 8.5.

Table 8.5 – Portfolio Variants

Variant	Description	Refer to Case
No CCS	No coal units are able to select CCS technology	-
No Nuclear	No nuclear resources are eligible for selection	-
No Coal 2032	All coal must retire or convert to gas by January 1, 2032	-
Offshore Wind	Counterfactual to the Preferred Portfolio selection: Offshore wind must be selected	-
No Forward Technology	No nuclear, hydrogen storage, 100-hour storage or biodiesel peaking	-
Geothermal	Counterfactual to the Preferred Portfolio selection: Geothermal must be selected	-
Hunter Retire	Require all Hunter units to retire no later than 1/1/2030	-
All Coal End of Life	Continue 2025 coal technology	See the No CCS variant
No New Gas	No new gas resources allowed	See the Preferred Portfolio
Force All Gas Conversions	Force all coal-to-gas options	See the No Coal 2032 variant

Each variant case begins with the same PLEXOS dataset inputs and assumptions, and adds the constraints to either force a selection, disallow a specific resource or resource type, delay a project or force retirements as outlined below.

No CCS

This variant removes the CCS option at Jim Bridger 3 and 4. The endogenous portfolio was integrated using the same method as the preferred portfolio. The purpose of this variant is to evaluate how the preferred portfolio would change if CCS were not a commercially viable

option. This variant was analyzed twice, once using the MN price-policy scenario and once using the MR price-policy scenario.

No Nuclear

This variant removes the Natrium™ demonstration project in 2030 and all other nuclear resources from available resource options. The endogenous portfolio was integrated using the same method as the preferred portfolio. The purpose of the variant is to evaluate resource alternatives in the absence of nuclear resource options. Additionally, this sensitivity seeks to evaluate the potential risk if nuclear resources are unable to achieve online and operating status for any reason.

No Coal 2032

In this variant all coal plants are assumed to retire no later than 2032. Coal plants are eligible to run past 2032 if gas conversion is selected at that plant. No CCS options are available in this variant. The endogenous portfolio was integrated using the same method as the preferred portfolio. The purpose of this variant is to evaluate how the preferred portfolio would change if external factors required coal plants to cease coal-fired operations by 2032.

Offshore Wind

Offshore wind was available for selection in all portfolios beginning in 2033, based on the timing of necessary transmission upgrades. As offshore wind has not been endogenously selected in the preferred portfolio, a minimum of 1000 MW was required to be selected in this variant. Additionally, the necessary onshore transmission required to enable offshore wind was available for selection by offshore wind or by any other appropriately located proxy resources to ensure that co-located resources could be selected to complement the offshore wind and that it is competitive with other options. This counterfactual is used to assess system impacts and the magnitude of the costs and benefits associated with offshore wind.

No Forward Technology

In this variant all nuclear, hydrogen storage, 100-hour battery, and biodiesel peaking resources are removed from the preferred portfolio and the portfolio is re-optimized without these resource options. The removal of 100-hour battery as an option in this variant is in response to stakeholder request.[22] The purpose of this variant is to evaluate the cost and risk impacts of limited new resource types becoming available in the future.

Geothermal Counterfactual

Like the offshore wind case, advanced geothermal units are available for selection in all portfolios in Central Oregon and Southern Utah starting in 2027. These resources require transmission upgrades to be enabled. Pursuant to stakeholder interest[23], as geothermal is not selected for the Preferred Portfolio, a minimum of 707 MW of geothermal resource must be built

[22] See Appendix M, stakeholder feedback form #55 (Utah Division of Public Utilities).
[23] See Appendix M, stakeholder feedback form #56 (Utah Clean Energy).

in Central Oregon or Southern Utah. This counterfactual is used to assess system impacts and the magnitude of costs associated with geothermal and its associated transmission requirements.

Hunter Retire

Responsive to stakeholder interest, a variant is considered that forces all three Hunter coal units to cease all operations by 2030.[24] This variant forces the retirement of the Hunter Plant in any year from 2028 to 2030. The purpose of this variant is to assess the impact on cost and emissions when Hunter is precluded from continued operation.

All Coal End of Life

> *The No CCS run selects coal at all current coal sites and does not choose to retire any eligible units. Please refer to the No CCS variant for results.*

In this variant all coal plants are assumed to run as coal-fired units using the technology present on the plant as of January 1, 2025, and are not eligible to retire during the study horizon unless otherwise required to do so. Dave Johnston units 1-3 along with Naughton units 1 and 2 still retire or cease coal-fired operation as necessary. Minority owned coal plants are also assumed to retire as necessary for environmental compliance. The purpose of this variant is to evaluate how the preferred portfolio would change if majority-owned coal resources were allowed to run as coal-fired to end-of-life.

No New Gas

> *The unconstrained integrated MN case does not select new natural gas resources. Please refer to the Preferred Portfolio for results.*

This variant assumes no new gas resources are allowed to be selected. This does not include the conversion of coal plants from coal-fired to gas-fired. The purpose of this variant is to evaluate the cost and risk impacts of replacing new gas resources selected in the preferred portfolio with other energy resources.

Force All Gas Conversions

> *The No Coal 2032 selected all plants eligible for gas conversion. Please refer to the No Coal 2032 variant for results.*

In this variant all coal plants eligible for gas conversion are forced to do so. The gas converted coal plants are allowed to retire endogenously, and the portfolio is re-optimized. The purpose of this variant is to evaluate the cost and risk impacts associated with gas conversion becoming the only future option for all coal-fired plants. Hunter and Huntington, which are not eligible for gas conversion, were eligible for alternative fuel conversion but were not forced to convert.

Integrated Portfolios

Portfolio integration involves combining resource selections from each of the initial jurisdictional portfolio results under a given price-policy scenario or variant. Every initial jurisdictional portfolio

[24] See Appendix M, stakeholder feedback form #53 (Sierra Club).

evaluates the entire system and all proxy resource options, plus the constraints specific to that jurisdiction. For proxy resources that can be allocated to any jurisdiction, the integration step adopts the largest quantity of each individual resource by year that was included in any of the jurisdictional studies, identified as 1) "UIWC" for Utah, Idaho, Wyoming and California, 2) "OR" for Oregon and 3) "WA" for Washington. Because of interconnection limits, it is generally not possible to sum the selections across the various jurisdictions, and the overall quantity might not be economic. For resources that are specific to a single jurisdiction, including demand-side resources and existing thermal resources, the integration step adopts the quantity from that specific jurisdiction's initial portfolio result. Given concerns related to the availability of transmission on an hourly basis between the West and East sides of PacifiCorp's system, the selection of proxy resources on the West is determined jointly by the Oregon and Washington initial jurisdictional portfolios, and the selection of proxy resources on the East is determined by the initial jurisdictional UIWC portfolio. Accordingly, only the jurisdictional portfolios that determine the selection of a given resource are eligible to participate in that resource.

Table 8.6 – Portfolio Integration Resource Example

Jurisidiction	Fixed Share	Initial Portfolio Selection (MW)	Total Allocation (MW)
Oregon	75%	150	112.5
Washington	25%	60	37.5
Total	100%		150

In this way, resource allocations are fixed based on jurisdictional selections in the year in which they are built and do not change over time. Where a proxy resource has additions in multiple years, only the quantity added in a given year is allocated, based on portfolio selections in that year. This integration process is applied to every initial portfolio.

The initial integration step has the potential to result in compliance shortfalls, as a portion of the resources that were identified for compliance may be shared with other jurisdictions. Thus, the final step of the integration process is to identify and remedy any such shortfalls in energy and capacity compliance.

Washington Portfolios

The integrated preferred portfolio reflects Washington customer energy and capacity needs and the CETA clean energy standards from 2030 onwards. The final integrated portfolio presents a CETA-compliant path towards the production of a quantity of clean megawatt hours that meets Washington's retail sales on an annual basis, as described in further detail in Appendix O (Washington's Clean Energy Action Plan). This CETA-compliant portfolio is a starting point for the analysis that will be provided in the forthcoming 2025 Clean Energy Implementation Plan (CEIP), expected to be filed with the Washington Utilities and Transportation Commission in October 2025.

The focus of this IRP filing is to present an integrated preferred portfolio that meets all state-specific requirements. As described in this chapter and further in Appendix Othe IRP preferred portfolio presents a strategy to get to a portfolio that is optimized to meet Washington CETA clean energy standards over the next twenty years. The following scenarios and sensitivities required by Washington rule are also included.

Per WAC 480-100-620(10): the IRP must also include a range of possible future scenarios and input sensitivities. These include:

- **Alternative Lowest Reasonable Cost** - WAC 480-100-620(10)(a) instructs utilities to "describe the alternative lowest reasonable cost and reasonably available portfolio that the utility would have implemented if not for the requirement to comply" with CETA's Clean Energy Transformation Standards. This case is comparable to the initial SCGHG price-policy scenario study but includes Washington-specific capacity requirements based on WRAP. This sensitivity includes the requirement to use the social cost of greenhouse gases (SC) price-policy assumption in resource acquisition decisions. In Chapter 9 – Modeling and Portfolio Selection Results, the company will analyze this portfolio in the context of both CETA and non-CETA compliant outcomes.

- **Climate Change** - WAC 480-100-620(10)(b) instructs utilities to "incorporate the best science available to analyze impacts including, but not limited to, changes in snowpack, streamflow, rainfall, heating and cooling degree days, and load changes resulting from climate change." Please see Appendix A for additional detail regarding how climate change is incorporated into the base load forecast. Climate change impacts are also incorporated in the base hydro forecast. Because the base forecast includes climate change, all the IRP analysis reflects impacts related to climate change and a separate sensitivity to include these impacts is not necessary.

- **Maximum Customer Benefit** - WAC 480-100-620(10)(c) instructs utilities to "model the maximum amount of customer benefits described in RCW 19.405.040(8) prior to balancing against other goals." The maximum customer benefit scenario focuses on adding distributed generation, demand response, and energy efficiency in Washington, as well as avoiding high-voltage transmission upgrades in PacifiCorp's Yakima and Walla Walla communities to minimize burdens and maximize benefits to Washington customers. Washington load forecast reflects the high private generation forecast. The portfolio assumes the social cost of greenhouse gas price-policy scenario and includes all available Washington energy efficiency and demand response. The study also removes Yakima and Walla Walla area transmission options and relies on increased small-scale renewables. Each of these studies is most pertinent to the State of Washington and are further discussed in Chapter 9 (Modeling and Portfolio Selection Results).

Sensitivity Case Definitions

PacifiCorp identified a variety of sensitivities outlined in Table 8.7 and discussed further in Chapter 9.

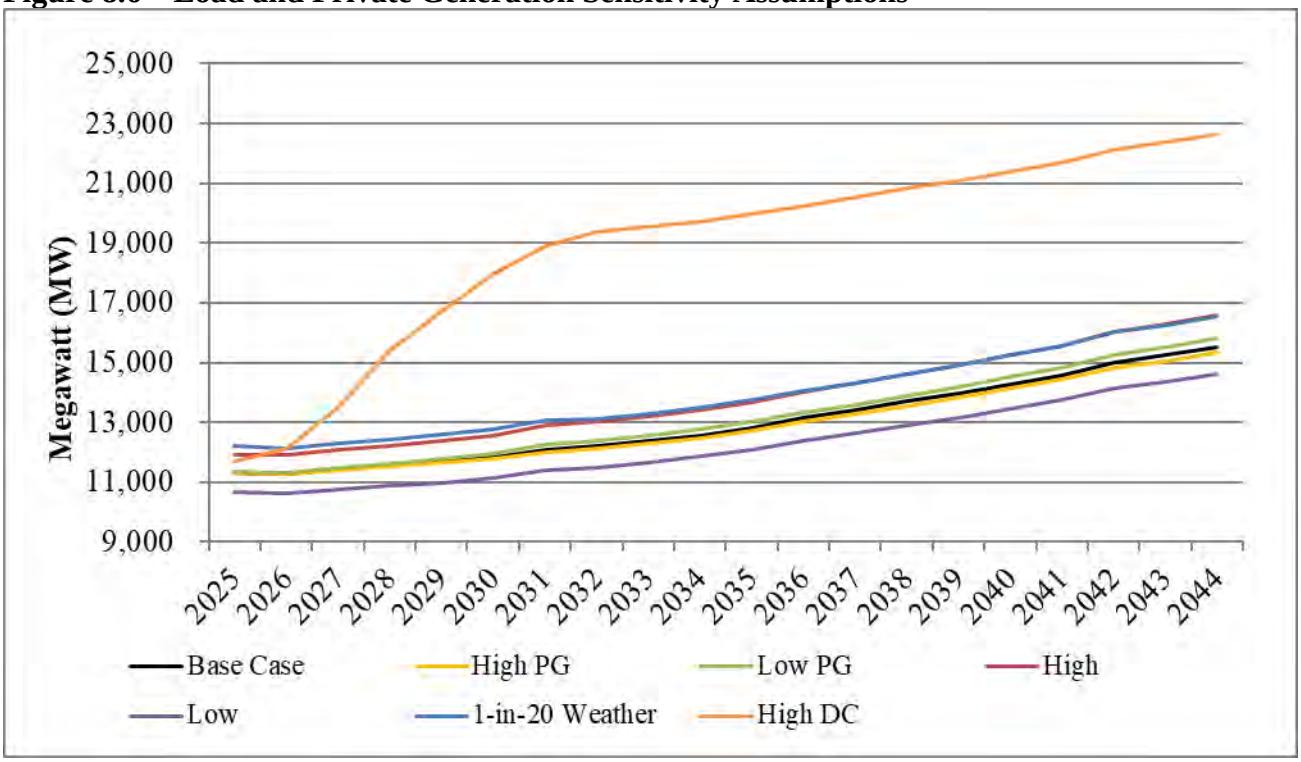
Table 8.7 – Sensitivity Case Definitions

Sensitivity	Definition
High Load Growth	Base load forecast replaced by a high load version
Low Load Growth	Base load forecast replaced by a low load version
1-20 Peak Load	Base load forecast replaced by a high load version using historical 20-year highest load
High Private Generation	Assumes lower load due to high private generation adoption
Low Private Generation	Assumes higher load due to low private generation adoption
Large Metered Load Growth	Assumes significant large-metered customer load growth
Low-Cost Renewables	Assumes high adoption of IRA/IIJA benefits leads to large cost declines
Low PTC/ITC eligibility	Assumes changes to IRA/IIJA leading to shorter PTC/ITC eligibility window
All CCS	Allows CCS to be selected at additional coal units
Business as Usual	Portfolio if no state requirements existed
Business Plan	First 3 years are aligned with the current business plan

Load Sensitivities

The 2025 IRP includes several sensitivities related to load forecast assumptions. Figure 8.6 provides a comparison of load by year for each case, including the base assumption for comparison. Definitions for all sensitivities are then discussed individually, below.

Figure 8.6 – Load and Private Generation Sensitivity Assumptions



High Load Growth

In this sensitivity the base load forecast is replaced with a high load forecast. The preferred portfolio is re-optimized with this new load forecast to evaluate the cost and risk impacts of higher loads.

Low Load Growth
In this sensitivity the base load forecast is replaced with a low load forecast. The preferred portfolio is re-optimized with this new load forecast to evaluate the cost and risk impacts of lower loads.

1 in 20 Peak Load
In this sensitivity the base load forecast based on median load conditions (exceedance in 10 of 20 years) is replaced with a higher load forecast based on peaks that reflect an expected 1 in 20 year exceedance level. The preferred portfolio is re-optimized with this new load forecast to evaluate the cost and risk impacts of higher peak loads.

High Private Generation
In this sensitivity the base load forecast is replaced with a new load forecast incorporating high private generation adoption which reduces load. The preferred portfolio is re-optimized with this new load forecast to evaluate the cost and risk impacts of a future with high private generation adoption.

Low Private Generation
In this sensitivity the base load forecast is replaced with a new load forecast incorporating low private generation adoption which increases load. The preferred portfolio is re-optimized with this new load forecast to evaluate the cost and risk impacts of a future with low private generation adoption.

Large-Metered Load Growth
In this sensitivity the base load forecast is replaced with a new load forecast incorporating high large-metered load growth. The preferred portfolio is re-optimized with this new load forecast to evaluate the cost and risk impacts of this future. A variety of transmission upgrades are necessary to meet the significant load increases contemplated in this sensitivity, including B2H. This portfolio uses the same integration process as the preferred portfolio to address any state compliance shortfalls.

Low-Cost Renewables

This sensitivity assumes high IRA/IIJA adoption results in significant cost reductions for PTC/ITC eligible resources, making them more likely to displace non-PTC/ITC eligible resources. The portfolio is fully endogenous and has gone through the same level of integration as the preferred portfolio. The purpose of this sensitivity is to show how the availability of lower cost renewables might impact cost and risk.

Low PTC and ITC Eligibility

This sensitivity assumes IRA/IIJA changes result in PTC and ITC eligibility ending in 2030. Resources coming online after 2030 do not have the cost reductions associated with PTC and ITC. The portfolio is fully endogenous and has gone through the same level of integration as the preferred portfolio. The purpose of this sensitivity is to show how lower than anticipated IRA/IIJA eligible resource availability might impact cost and risk.

All CCS

This sensitivity allows CCS to be selected at Wyodak, Hunter Units 1-3, Huntington Units 1 and 2, and Dave Johnston Unit 4, in addition to the option of CCS at Jim Bridger Units 3 and 4. , This sensitivity relies on the assumption that it is feasible to complete installations at all of these units prior to 2032. The portfolio is fully endogenous and has gone through the same level of integration as the preferred portfolio. The purpose of this variant is to evaluate how the preferred portfolio would change if CCS were a commercially viable option at more than one coal site before 2032.

Business As Usual[25] (No Pending Legislation or State Requirements; Locked Coal Assumptions)

In this sensitivity, all pending legislation and state requirements are removed so that the only obligations to be met are load and federal policy obligations. Coal outcomes are also set so that coal plants retire no earlier than assumed in the 2017 IRP Update except to the extent that updated commitments or requirements supersede the older assumptions. The portfolio is otherwise fully endogenous. The purpose of this variant is to evaluate how the preferred portfolio would change if no potential state requirements or early economic retirements were considered.

Business Plan Sensitivity

The unconstrained integrated MN case does not select new resources in the first three years, please refer to the Preferred Portfolio for results.

In the 2025 IRP, this case has the same assumptions as the integrated preferred portfolio. For this reason, no additional sensitivity is needed. The case complies with the Utah requirement to perform a business plan sensitivity consistent with the commission's order in Docket No. 15-035-04. Over the first three years, resources align with those assumed in PacifiCorp's current Business Plan. Beyond the first three years of the study period, unit retirement assumptions are aligned with those identified in the preferred portfolio. All other resource selections are optimized using the PLEXOS models.

[25] Per the Wyoming Public Service Commission's (WPSC) 2019 Investigation Order (DOCKET NO. 90000-144-XI-19, and DOCKET NO. 90000-147-XI-19), "reference case" is the formal terminology for the business-as-usual study. Regarding this study, the WPSC mandates the following:

> "In the anticipated 2021 IRP, and in IRPs and updates thereto filed by the Company thereafter, Rocky Mountain Power shall:
>
> a) Include a Reference Case based on the 2017 IRP Updated Preferred Portfolio, incorporating updated assumptions, such as load and market prices and any known changes to system resources and only incorporate environmental investments or costs required by current law"

This case was the subject of stakeholder feedback and discussion in the 2025 IRP public input meeting series. See Appendix M, stakeholder feedback form #35 (Wyoming Energy Authority).

CHAPTER 9 – MODELING AND PORTFOLIO SELECTION RESULTS

CHAPTER HIGHLIGHTS

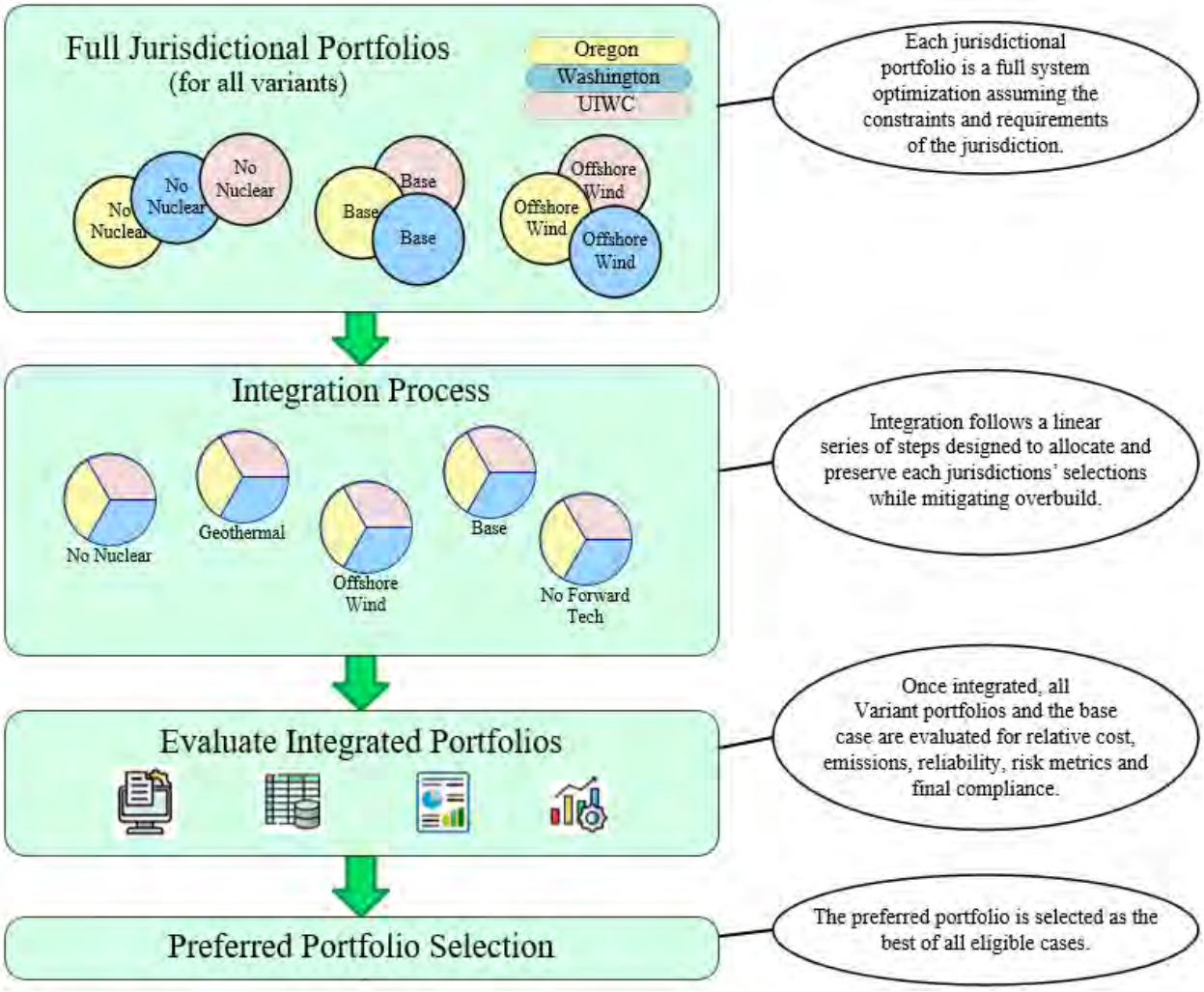
- Using cost and risk metrics to evaluate a wide range of resource portfolios, PacifiCorp selected a preferred portfolio that builds on its vision to deliver energy affordably, reliably, and responsibly.
- PacifiCorp's selection of the 2025 IRP preferred portfolio is supported by comprehensive data analysis and an extensive public-input process. The preferred portfolio includes continued operation of most of its existing fleet, plus substantial new renewables, facilitated by incremental transmission investments, along with demand-side management (DSM) resources, storage resources, and advanced nuclear.
- The 2025 IRP preferred portfolio builds upon resources which have been contracted since the 2023 IRP, including 520 megawatts (MW) of new storage resources. The 2025 IRP preferred portfolio includes near-term proxy resource selections that align with recent transmission cluster studies, and it is expected that forthcoming RFPs as outlined in the action plan will soon be soliciting and evaluating resources to fulfill these needs.
- The 2025 IRP preferred portfolio also includes the 500 MW advanced nuclear Natrium^{TM} demonstration project, anticipated to achieve online status by the end of 2031. Over the planning horizon, the 2025 IRP preferred portfolio includes 3,782 MW of new wind, and 5,912 MW of new solar, of which 1,147 MW is small-scale.
- To facilitate the delivery of new renewable energy resources to PacifiCorp customers across the West, the preferred portfolio includes additional transmission investment. Specifically, the portfolio includes multiple upgrades increasing connection from Utah South into the Wasatch Front area, and additional upgrades that increase transfer and interconnection capability on the west side of PacifiCorp's system.
- Driven in part by the need for low-cost firm capacity, existing coal-fired facilities generally continue to operate through the end of the planning period. Majority-owned coal units which are required to cease coal-fired operation were converted to natural gas where the option was available.
- In the 2025 IRP, four factors related to emitting resources drive a reduction in CO_2 emissions after 2025. These factors are retirements (minority-owned units and Dave Johnston 3), additional natural gas conversions (Naughton 1 and 2 and Dave Johnston 1 and 2), reduced capacity factors at existing coal and natural gas facilities (influenced by additions of renewable resources and energy storage), and installation of carbon capture and sequestration (CCS) technology (Jim Bridger 3 and 4). In combination these factors result in 2030 emissions that are less than half of the 2025 level. After 2030, changes in capacity factors are the primary driver, with capacity factors falling initially because of renewable resource additions but rising back to the 2030 level by the end of the horizon in response to growing loads and the expiration of existing contracted resources.

Introduction

This chapter reports modeling and portfolio selection results for the resource portfolios developed with a broad range of input assumptions informed by the PLEXOS modeling. Using model data from the portfolio-development process and subsequent cost and risk analysis of unique portfolio alternatives, the following discussion describes PacifiCorp's preferred portfolio selection process and presents the 2025 IRP preferred portfolio.

This chapter is organized around the portfolio development, modeling and evaluation steps identified in the previous chapter and covers the portfolio cost and risk analysis for the variant portfolios, including selection of the preferred portfolio. As illustrated in Figure 9.1, the final preferred portfolio selection is informed by all relevant modeling results.

Figure 9.1 – Portfolio Integration and Selection Workflow



This chapter also presents discussion of Oregon's compliance position in the preferred portfolio.

Results of resource portfolio cost and risk analysis from each step are presented in the following discussion of PacifiCorp's portfolio evaluation processes. Stochastic analysis is also discussed in Volume II, Appendix H (Stochastics).

Initial Portfolio Development

As discussed in Volume 1, Chapter 8 the portfolio development process in the 2025 IRP is an iterative process where each case, both by jurisdiction and variant, is looped through multiple phases of LT and ST modeling, leveraging results from a prior phase to inform the next phase. Once sufficient phases are complete, an initial study with high reliability and low costs over the study horizon is selected from each jurisdiction's results for integration. Table 9.1 below shows the various phases of the Oregon MN initial jurisdictional run to show how iterative jurisdictional portfolios were evaluated and selected for integration. Given the initial views of these runs, and subsequent integrating, the present-value revenue requirement (PVRR) and unserved energy stream over 21 years were the key factors determining which phase was selected for integration. In Table 9.1, phase 17 was selected as the Oregon initial portfolio for inclusion in the MN integrated portfolio. This selection takes into consideration the PVRR of $26,298 million, and the stream of unserved energy costs that led to a total cost of $0 and had no unserved energy after 2027. Other phases which were considered were phase 11, phase 15, and phase 5, however the higher PVRR of phases 15 and 5, and the fact that phase 17 was more WRAP compliant than phase 11 led to phase 17 being selected.

Table 9.1 – Iterative phases of Oregon MN portfolio

Phase	Jurisdiction	Price-Policy	21 Year PVRR	Unserved Energy Cost
0	OR	Medium Gas, No CO2	26,108	1
1	OR	Medium Gas, No CO2	26,809	0
2	OR	Medium Gas, No CO2	26,314	0
3	OR	Medium Gas, No CO2	26,353	1
4	OR	Medium Gas, No CO2	26,405	0
5	OR	Medium Gas, No CO2	26,372	0
6	OR	Medium Gas, No CO2	26,370	1
7	OR	Medium Gas, No CO2	26,343	0
8	OR	Medium Gas, No CO2	26,442	1
9	OR	Medium Gas, No CO2	26,365	0
10	OR	Medium Gas, No CO2	26,498	2
11	OR	Medium Gas, No CO2	26,298	0
12	OR	Medium Gas, No CO2	26,461	1
13	OR	Medium Gas, No CO2	26,366	0
14	OR	Medium Gas, No CO2	26,447	1
15	OR	Medium Gas, No CO2	26,361	0
16	OR	Medium Gas, No CO2	26,388	2
17	OR	Medium Gas, No CO2	26,298	0
18	OR	Medium Gas, No CO2	26,463	1
19	OR	Medium Gas, No CO2	27,058	0

The fully integrated portfolios and variants differ based on retirement timing, the impact of federal CO_2 policy, requested or required resource availability variations, and options for gas conversion or CCS retrofit for certain units. The portfolios also differ based on natural gas and proxy CO_2 policy assumptions, resulting in uniquely optimized combinations of resources, transmission, and thermal retirement options.

As discussed in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach), each variant portfolio went through the iterative process.

Final selection of the top-performing portfolio and preferred portfolio selection also include an assessment of compliance with CETA and Oregon's HB 2021.

Jurisdictional Shares of the Preferred Portfolio

Table 9.2 through Table 9.4 present each jurisdiction's assumed *share* of total preferred portfolio resources as contained in the integrated preferred portfolio. These shares are based on the results of full jurisdictional portfolios that reflect planning requirements specific to the different jurisdictions, as discussed in the next section. For more information about how jurisdictional portfolios are determined, refer to Chapter 8.

Table 9.2 – Oregon Share[1, 2, 3]

OR Shares by Resource Type and Year, Installed MW																						
	Installed Capacity, MW																					
Resource	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Nuclear	-	-	-	-	-	-	-	130	-	-	-	-	-	-	-	-	-	-	-	-	-	130
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19	-	4	-	18	40
DSM - Energy Efficiency	-	-	97	101	107	114	115	110	113	108	109	111	110	106	102	116	123	107	114	92	90	2,044
DSM - Demand Response	-	0	-	48	16	7	-	5	1	3	3	11	-	11	4	23	4	-	9	-	8	153
Renewable - Wind	-	-	-	16	445	939	-	1	-	22	260	30	131	28	0	282	37	-	15	-	72	2,278
Renewable - Utility Solar	-	-	-	167	135	1,268	136	180	302	169	10	-	0	0	416	78	9	-	-	148	56	3,074
Renewable - Small Scale Solar	-	-	-	-	-	320	2	18	26	21	30	132	0	309	-	-	110	-	-	143	36	1,147
Renewable - Battery, < 8 hour	-	-	1	280	100	128	-	119	39	210	20	47	-	46	-	107	55	-	-	-	-	1,152
Renewable - Battery, 24+ hour	-	-	-	-	-	272	88	-	-	-	-	-	7	79	33	934	102	210	397	192	353	2,667
Potential Solar Acceleration[2]				***794***		***(794)***																

Table 9.3 – Washington Share[4]

WA Shares by Resource Type and Year, Installed MW																						
	Installed Capacity, MW																					
Resource	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Nuclear	-	-	-	-	-	-	-	32	-	-	-	-	-	-	-	-	-	-	-	-	-	32
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	-	0	13	16	15	17	18	18	19	19	20	19	19	15	14	12	11	11	10	8	7	280
DSM - Demand Response	-	0	-	15	2	2	-	-	-	-	-	8	-	6	1	1	1	-	1	-	14	51
Renewable - Wind	-	-	-	5	148	313	-	-	-	7	87	10	44	9	0	94	12	-	5	-	24	758
Renewable - Utility Solar	-	-	-	56	45	423	45	60	101	56	3	-	0	0	139	26	3	-	-	49	19	1,025
Renewable - Small Scale Solar	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	0
Renewable - Battery, < 8 hour	-	-	-	865	114	168	-	-	-	-	-	-	-	129	67	7	12	-	5	-	-	1,367
Renewable - Battery, 24+ hour	-	-	-	-	-	238	3	3	4	3	4	4	4	4	4	4	4	5	5	5	5	298
Potential Solar Acceleration[4]				***212***		***(212)***																

[1] See Appendix M, stakeholder feedback form #49 (Utah Association of Energy Users).
[2] While the 2025 IRP preferred portfolio indicates that a largely just-in-time strategy is the most economic means of achieving compliance with Oregon's clean energy compliance requirements, PacifiCorp's 2025 CEP will evaluate other alternatives like the potential accelerated compliance indicated in Table 9.2. For more details, please refer to Appendix P (Oregon Clean Energy Update)
[3] Planned Energy efficiency and demand response selections in 2025 and 2026 are not presented in Tables 9.2 through 9.4.

Table 9.4 – Utah, Idaho, Wyoming, and California Share

UIWC Shares by Resource Type and Year, Installed MW																						
	Installed Capacity, MW																					
Resource	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Nuclear	-	-	-	-	-	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	338
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	-	0	99	103	117	130	196	163	167	168	170	185	218	193	177	172	170	197	114	106	86	2,931
DSM - Demand Response	-	1	-	-	2	111	99	-	-	-	-	2	112	-	-	0	57	106	19	26	30	566
Renewable - Wind	-	-	-	-	200	200	344	-	-	-	-	-	0	-	-	-	-	-	-	-	-	744
Renewable - Utility Solar	-	-	-	-	-	-	668	-	-	-	-	-	0	-	-	-	-	-	-	-	-	668
Renewable - Small Scale Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery, < 8 hour	-	-	1	-	27	-	-	-	-	-	-	-	0	-	-	-	-	713	-	459	733	1,933
Renewable - Battery, 24+ hour	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	104	-	-	-	105

Full Jurisdictional Portfolios

Each jurisdiction's resource selections begin with a view of the entire system as optimized under that jurisdiction's particular constraints. These idealized views of the system allow each jurisdiction's preferred resource selections to be identified. These portfolios are referred to as the 'full jurisdictional portfolios' and show the selections prior to integration.

The following portfolios shown in Table 9.5 through Table 9.7 report the entirety of each jurisdictional portfolio's selections when planning for the entire system, which were then integrated into the preferred portfolio. This same integration process is used to develop integrated portfolios specific to each variant and price-policy scenario, and the preferred portfolio is selected based on the results for the integrated portfolios.

[4] While the 2025 IRP preferred portfolio indicates that a largely just-in-time strategy is the most economic means of achieving CETA compliance, PacifiCorp's 2025 CEIP will evaluate other alternatives like the potential accelerated compliance indicated in Table 9.3.For more details, please refer to Appendix O (Washington Clean Energy Action Plan)

Table 9.5 – Oregon Full Jurisdictional Portfolio

Summary Portfolio Capacity by Resource Type and Year, Installed MW																						
	Installed Capacity, MW																					
Resource	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**Total**
Expansion Options																						
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	500
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19	-	4	-	18	41
DSM - Energy Efficiency	92	89	201	209	220	237	306	280	283	280	300	309	333	303	283	291	266	286	252	230	189	5,239
DSM - Demand Response	18	2	-	53	17	9	53	5	1	3	3	11	259	15	50	23	4	100	9	50	25	710
Renewable - Wind	-	-	-	21	260	1,066	100	51	-	29	347	40	175	37	-	376	50	-	20	-	96	2,668
Renewable - Small Scale Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar	-	-	-	122	99	1,871	19	220	315	225	13	-	-	-	554	104	12	-	-	197	75	3,826
Renewable - Small Scale Solar	-	-	-	-	-	320	2	18	26	21	30	132	-	309	-	-	110	-	-	143	36	1,147
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery, < 8 hour	-	-	-	876	255	228	31	119	39	210	20	83	-	104	100	314	58	-	2	-	-	2,439
Renewable - Battery, 8-23 hour	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	224	-	-	-	-	-	241
Renewable - Battery, 24+ hour	-	-	-	-	-	134	-	-	-	-	-	-	-	59	4	752	128	-	341	-	59	1,477
Other Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	
Existing Unit Changes																						
Coal Plant Retirements - Minority Owned	-	(82)	-	(33)	(123)	(148)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(386)
Coal Plant Retirements	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)
Coal Plant Ceases as Coal	-	(357)	-	-	(205)	(1,387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,949)
Coal - CCS	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	(526)	-	-	-	0
Coal - Gas Conversions	-	46	-	-	-	687	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(418)	315
Gas Plant Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(79)	(79)
Retire - Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Non-Thermal	-	-	-	-	-	-	-	-	-	(3)	-	-	-	(32)	-	-	-	-	-	-	-	(35)
Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Wind PPA	-	(64)	-	-	-	(99)	(200)	-	-	-	-	-	-	-	-	-	(333)	-	-	-	-	(696)
Expire - Solar PPA	-	-	-	(2)	-	-	(9)	-	-	-	-	-	(100)	-	-	-	(65)	-	-	(230)	-	(407)
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(47)	(3)	-	(50)
Expire - Other	-	520	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	500
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**110**	**153**	**201**	**1,026**	**523**	**3,444**	**302**	**1,193**	**664**	**765**	**713**	**575**	**667**	**795**	**1,008**	**2,084**	**249**	**(140)**	**581**	**387**	**(18)**	

Table 9.6 – Washington Full Jurisdictional Portfolio

Summary Portfolio Capacity by Resource Type and Year, Installed MW																						
	Installed Capacity, MW																					
Resource	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Expansion Options																						
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	500
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	92	89	224	235	215	234	289	287	291	290	316	323	356	324	304	293	278	302	268	234	186	5,430
DSM - Demand Response	18	2	2	197	5	17	-	-	-	-	-	43	-	17	24	8	5	331	31	27	107	834
Renewable - Wind	-	-	-	-	1,607	-	260	1	-	-	-	-	-	-	-	-	-	-	-	-	-	1,868
Renewable - Small Scale Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar	-	-	-	201	138	463	1,437	770	527	418	772	249	100	1	-	-	-	-	-	-	-	5,076
Renewable - Small Scale Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery, < 8 hour	-	-	38	856	232	1,376	-	-	-	-	-	-	-	129	67	66	129	149	646	170	1,357	5,215
Renewable - Battery, 8-23 hour	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery, 24+ hour	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Existing Unit Changes																						
Coal Plant Retirements - Minority Owned	-	(82)	-	(33)	(123)	(148)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(386)
Coal Plant Retirements	-	-	-	(906)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(906)
Coal Plant Ceases as Coal	-	(357)	-	-	(205)	(2,679)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(3,241)
Coal - CCS	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(526)	0
Coal - Gas Conversions	-	311	-	-	205	1,979	(330)	-	-	-	-	-	-	-	-	-	-	-	-	-	(448)	1,717
Gas Plant Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Non-Thermal	-	-	-	-	-	-	-	-	-	(3)	-	-	-	(32)	-	-	-	-	-	-	-	(35)
Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Wind PPA	-	(64)	-	-	-	(99)	(200)	-	-	-	-	-	-	-	-	-	(333)	-	-	-	-	(696)
Expire - Solar PPA	-	-	-	(2)	-	-	(9)	-	-	-	-	-	(100)	-	-	-	(65)	-	-	(230)	-	(407)
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(47)	(3)	-	(50)
Expire - Other	-	520	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	500
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**110**	**418**	**264**	**548**	**2,074**	**1,669**	**1,447**	**1,558**	**818**	**705**	**1,088**	**615**	**356**	**439**	**395**	**367**	**14**	**782**	**898**	**198**	**656**	

Table 9.7 – Utah, Idaho, Wyoming, California (UIWC) Full Jurisdictional Portfolio

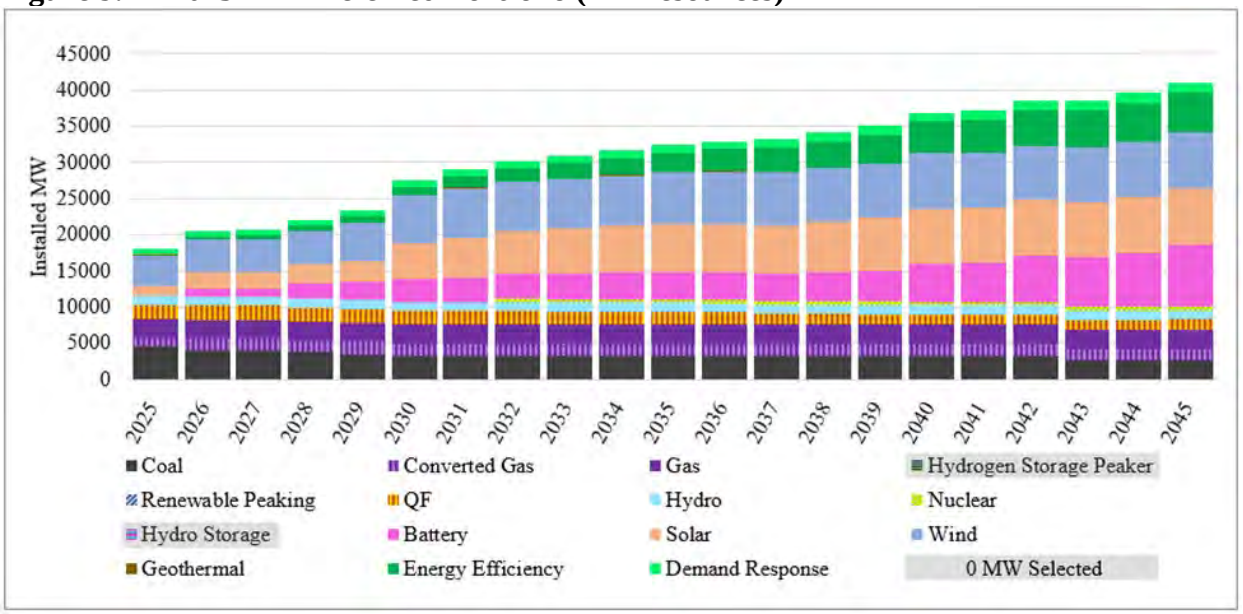
Summary Portfolio Capacity by Resource Type and Year, Installed MW																						
	Installed Capacity, MW																					
Resource	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Expansion Options																						
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	500
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	92	89	164	170	182	196	270	236	247	251	261	286	312	284	278	257	252	283	216	200	165	4,691
DSM - Demand Response	18	2	-	2	7	112	99	-	-	-	5	39	115	3	-	4	70	106	43	30	32	687
Renewable - Wind	-	-	-	-	306	684	344	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,334
Renewable - Small Scale Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar	-	-	-	153	12	79	668	-	31	123	133	3	-	-	-	2	-	-	-	65	-	1,269
Renewable - Small Scale Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery, < 8 hour	-	-	-	193	71	224	-	-	-	-	85	171	4	474	249	140	469	713	896	1,097	733	5,519
Renewable - Battery, 8-23 hour	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery, 24+ hour	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	104	-	-	-	104
Other Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Existing Unit Changes																						
Coal Plant Retirements - Minority Owned	-	(82)	-	(33)	(123)	(148)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(386)
Coal Plant Retirements	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)
Coal Plant Ceases as Coal	-	(357)	-	-	(205)	(700)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,262)
Coal - CCS	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	(526)	-	-	0
Coal - Gas Conversions	-	251	-	-	144	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	239
Gas Plant Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Non-Thermal	-	-	-	-	-	-	-	-	-	(3)	-	-	-	(32)	-	-	-	-	-	-	-	(35)
Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Wind PPA	-	(64)	-	-	-	(99)	(200)	-	-	-	-	-	-	-	-	-	(333)	-	-	-	-	(696)
Expire - Solar PPA	-	-	-	(2)	-	-	(9)	-	-	-	-	-	(100)	-	-	-	(65)	-	-	(230)	-	(407)
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(47)	(5)	-	(52)
Expire - Other	-	520	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	500
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**110**	**358**	**164**	**263**	**394**	**874**	**1,172**	**736**	**278**	**371**	**484**	**499**	**331**	**729**	**527**	**403**	**393**	**1,206**	**426**	**1,157**	**910**	

The 2025 IRP Preferred Portfolio

The preferred portfolio is selected from among all of the variant and price-policy portfolios after integration. PacifiCorp's selection of the 2025 IRP preferred portfolio is supported by comprehensive data analysis and an extensive public-input process, described in the chapters that follow. Figure 9.2 shows that PacifiCorp's 2025 preferred portfolio continues to include substantial new renewables, facilitated by incremental transmission investments, demand-side management (DSM) resources, significant storage resources, and advanced nuclear. The 2025 IRP preferred portfolio is in addition to previously contracted resources, some of which have not yet achieved commercial operation, including: 1,564 MW of wind, 1,736 MW of solar additions, and 1,072 MW of battery storage capacity. These resources are scheduled to come online in the 2024 to 2026 timeframe.

The 2025 IRP preferred portfolio includes the advanced nuclear Natrium™ demonstration project, anticipated to achieve online status by fall 2031. By the end of 2032, the preferred portfolio includes 2,408 MW of energy storage resources, including 605 MW of iron-air batteries with one-hundred-hour storage capability. Advancement of these technologies will be critical to meeting growing loads and achieving environmental compliance requirements. Over the 21-year planning horizon, the 2025 IRP preferred portfolio includes 3,782 MW of new wind and 5,912 MW of new solar.

Figure 9.2 – 2025 IRP Preferred Portfolio (All Resources)



* Technologies highlighted in gray were available for selection in IRP modeling but are not part of PacifiCorp's existing resource mix and were not selected for the preferred portfolio.

New since the 2023 IRP, the 2025 IRP preferred portfolio includes a number of smaller incremental upgrades to enhance transfer capability, including lines between southern Utah and the Wasatch Front in Utah, Walla Walla and Yakima in Washington, Walla Walla and Deschutes County in Oregon, and Summer Lake and Deschutes County in Oregon.

Many of the transmission upgrades and interconnection options modeled for the 2025 IRP reflect the results of PacifiCorp's "cluster study" process for evaluating proposed resource additions. Since 2020, PacifiCorp has been evaluating all newly proposed resource additions in an area at the same time, using a cluster study process that identifies collective solutions that can allow projects that are ready to move forward to do so in a timely fashion. Eight out of the fourteen transmission selections are expected to increase interconnection capability only, while the other six transmission selections provide both interconnection capability and increased transfer capability among the transmission areas modeled in the IRP. Table 9.8 summarizes the incremental transmission projects in the 2025 IRP preferred portfolio.

Table 9.8 – Transmission Projects Included in the 2025 IRP Preferred Portfolio [1,2]

		Export (MW)	Import (MW)	Interconnect (MW)	Build Investment ($m)	Build (%)	From	To
2026	Utah South - Wasatch Front: 138 kV reinforcement #1	250	250	250	30	100%	Utah South	Wasatch Front
2028	Cluster 1 Area 11: Willamette Valley	0	0	199	14	100%	n/a	n/a
	Cluster 1 Area 14: Summer Lake	400	400	400	111	100%	Summer Lake	Hemingway
	Cluster 1/2/3: Walla Walla	0	0	393	328	100%	n/a	n/a
	Serial queue: Central Oregon	0	0	152	4	100%	n/a	n/a
	Serial/Cluster 1/2: Yakima	0	0	628	64	100%	n/a	n/a
	Utah South - Wasatch Front: 138 kV reinforcement #2	200	200	200	12	100%	Utah South	Wasatch Front
2029	Cluster 2 Area 23: Willamette Valley	0	0	393	2	100%	n/a	n/a
2030	Cluster 2 Area 19: Summer Lake to Central Oregon 500 kV	1,500	1,500	670	1,283	100%	Summer Lake	Central OR
	Walla Walla - Yakima 230 kV	400	400	400	142	100%	Walla Walla	Yakima
2031	Serial through Cluster 1 Area 13: Southern Oregon	0	0	231	42	100%	n/a	n/a
2032	Cluster 1 Area 12: Southern Oregon	0	0	300	303	100%	n/a	n/a
2033	Cluster 2 Area 18: Central Oregon 500 kV Substation	0	0	518	372	100%	n/a	n/a
2039	Walla Walla - Central Oregon 500 kV	1,500	1,500	670	1,463	100%	Walla Walla	Central OR
Grand Total		**4,250**	**4,250**	**5,404**	**4,169**			

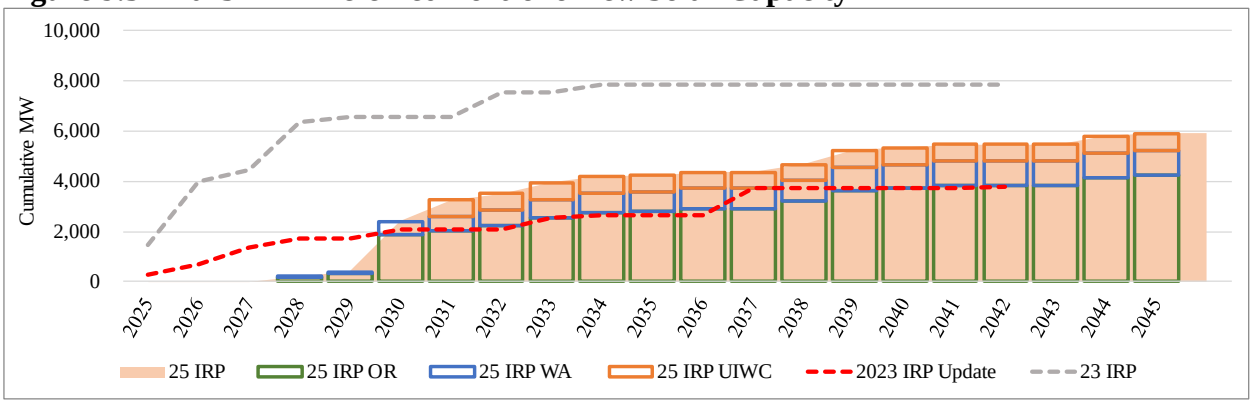
[1] Export and import values represent total transfer capability (TTC). The scope and cost of transmission upgrades are planning estimates. Actual scope and costs will vary depending upon the interconnection queue, the transmission service queue, the specific location of any given generating resource and the type of equipment proposed for any given generating resource.

[2] Transmission upgrades frequently include primarily all-or-nothing components, though the cluster study process allows for some project-specific timing and costs.

New Solar Resources

The 2025 IRP preferred portfolio includes 2,092 MW of new utility scale solar by the end of 2030, 3,822 MW by the end of 2035, and 4,765 MW by the end of 2045. Additionally, the 2025 IRP preferred portfolio includes 320 MW of new small scale solar by the end of 2030, 417 MW by the end of 2035, and 1,157 MW by the end of 2045. These cumulative totals are shown in Figure 9.3.

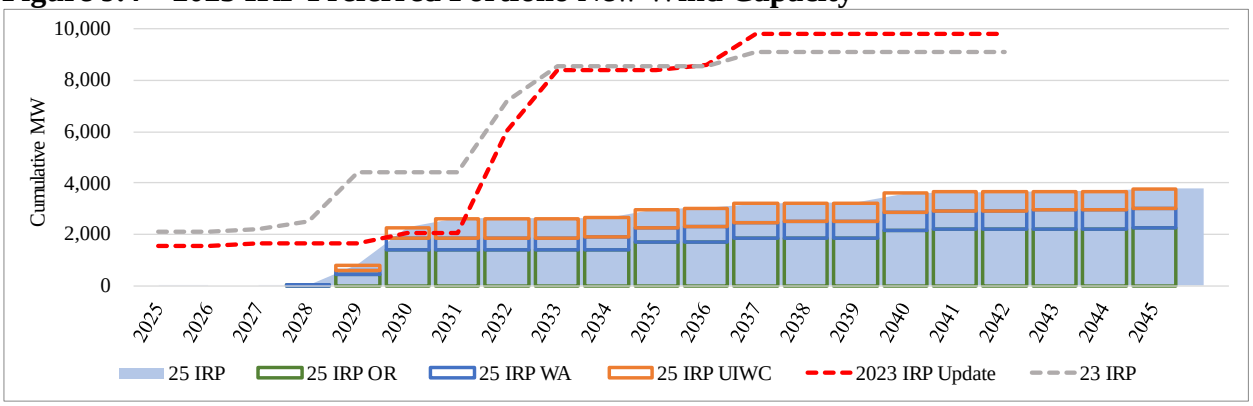
Figure 9.3 – 2025 IRP Preferred Portfolio New Solar Capacity



New Wind Resources

As shown in Figure 9.4, PacifiCorp's 2025 IRP preferred portfolio includes 2,267 MW of new wind generation by the end of 2030, 2,988 MW by the end of 2035, and 3,782 MW of cumulative new wind by the end of 2045. Of note, all wind selections are utility scale.

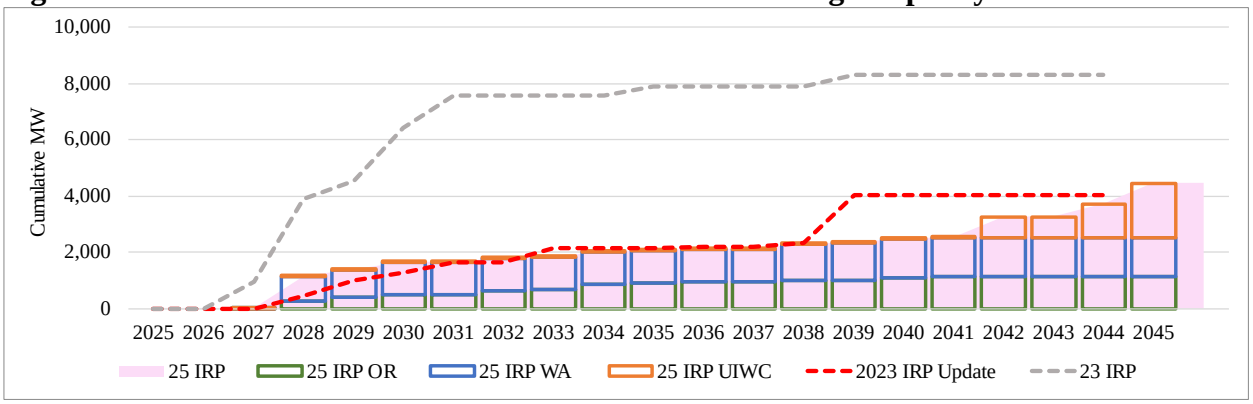
Figure 9.4 – 2025 IRP Preferred Portfolio New Wind Capacity



New Storage Resources

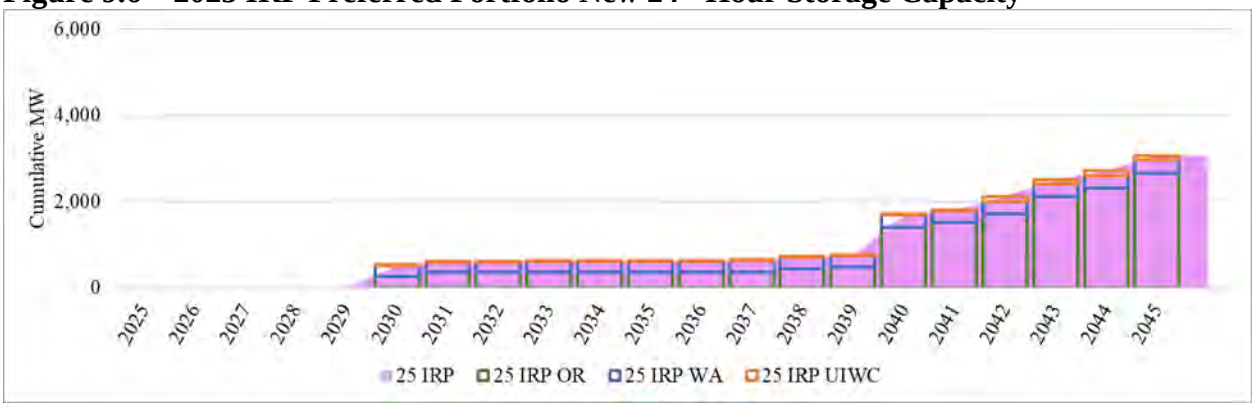
New storage resources in the 2025 IRP preferred portfolio are summarized in Figure 9.5 and 9.X. The 2025 IRP preferred portfolio includes 1,684 MW of new 4-hour storage resources by the end of 2030, 2,072 MW by the end of 2035 and 4,451 MW by the end of 2045. Additionally, the 2025 IRP preferred portfolio includes 511 MW of storage with at least 24 hours duration by the end of 2030 and growing to 616 MW by 2035 and 3,073 MW by 2045. Cumulative storage selections, inclusive of both short and long duration resources, total 7,524 MW by 2045.

Figure 9.5 – 2025 IRP Preferred Portfolio New 4-Hour Storage Capacity[1,2]



[1] The 2023 IRP Update includes 400 MW of PVS battery (Green River solar+storage) in 2026 that has since been signed and thus is not categorized as new storage capacity in the 2025 IRP.
[2] The 2023 IRP and 2023 IRP Update totals shown in Figure 9.5 include a minimal amount of intermediate duration storage.

Figure 9.6 – 2025 IRP Preferred Portfolio New 24+ Hour Storage Capacity[1]

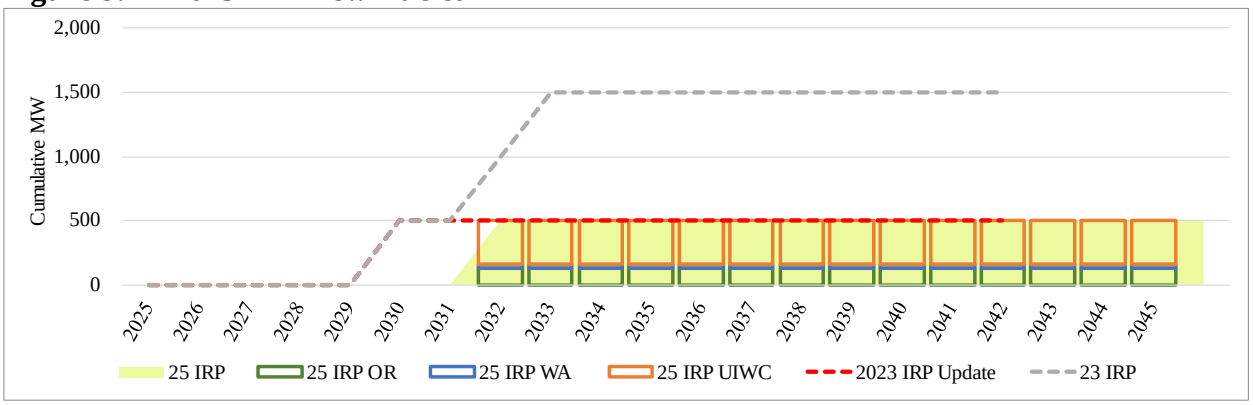


[1]The 2025 IRP preferred portfolio also includes 41 MW of renewable peaking resources by the end of the planning horizon.

New Nuclear Resources

The 2025 IRP includes new advanced nuclear as part of its least-cost, least-risk preferred portfolio. As shown in Figure 9.7, the 500 MW advanced nuclear Natrium™ demonstration project is currently scheduled to come online by fall 2031.

Figure 9.7 – 2025 IRP New Nuclear[1]



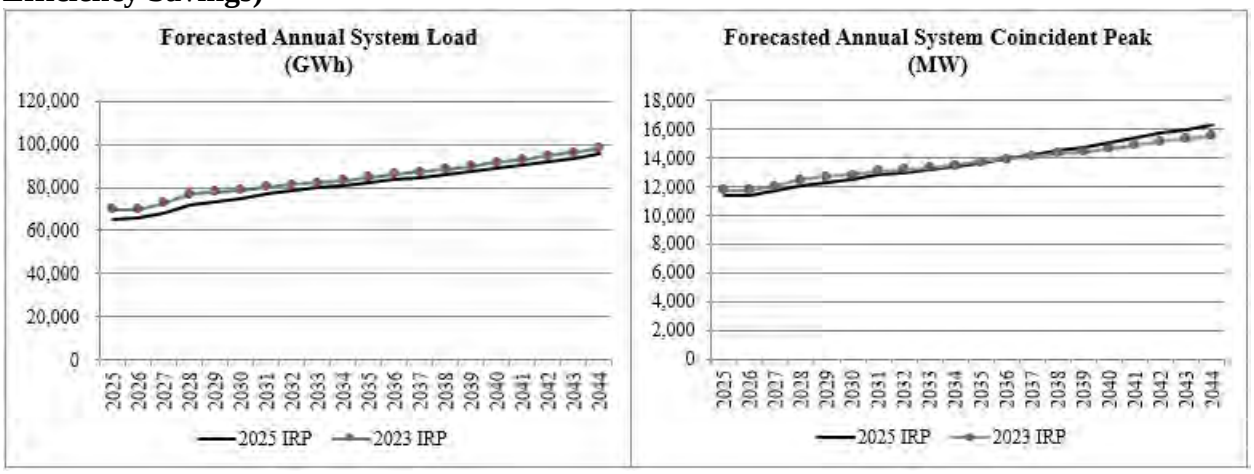
[1] While the 500 MW advanced nuclear Natrium™ demonstration project is currently scheduled to come online by the fall of 2031, the PLEXOS model works best with beginning of year start dates for expansion candidates, so a start date of 1/1/2032 was assumed for the Natrium™ demonstration project in modeling.

Demand-Side Management

PacifiCorp evaluates new DSM opportunities, which includes both energy efficiency and demand response programs, as a resource that competes with traditional new generation and wholesale power market purchases when developing resource portfolios for the IRP. The optimal determination of DSM resources therefore results in the selection of all cost-effective DSM as a core function of IRP modeling. Consequently, the load forecast used as an input to the IRP does not reflect any incremental investment in new energy efficiency programs; rather, the load forecast is reduced by the selected additions of energy efficiency resources in the IRP. Figure 9.8 shows that PacifiCorp's load forecast before incremental energy efficiency savings has decreased relative to projected loads used in the 2023 IRP. On average, forecasted system load is down 3.9 percent and forecasted coincident system peak is down 0.6 percent when compared to the 2023 IRP. Over

the planning horizon, the average annual growth rate, before accounting for incremental energy efficiency improvements, is 2.03 percent for load and 1.91 percent for peak. Changes to PacifiCorp's load forecast are driven by lower projected demand from new large customers who are expected to bring their own resources, thus lowering the commercial forecast.[5]

Figure 9.8 – Load Forecast Comparison between Recent IRPs (Before Incremental Energy Efficiency Savings)

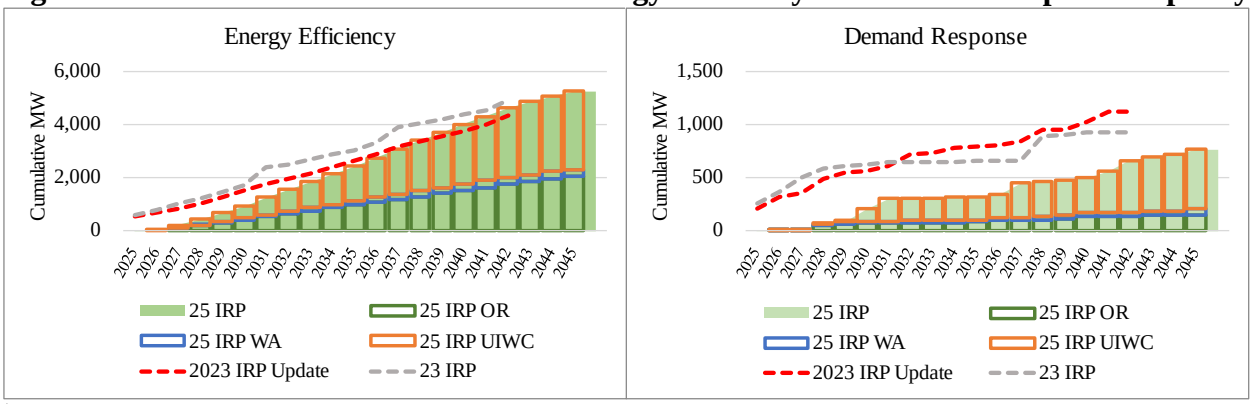


DSM resources continue to play a key role in PacifiCorp's resource mix. The chart to the left in Figure 9.9 compares total energy efficiency capacity savings in the 2025 IRP preferred portfolio relative to the 2023 IRP preferred portfolio. Cumulative capacity of energy efficiency programs in the 2025 IRP preferred portfolio totals 5,436 MW by the end of the planning period.

In addition to continued investment in energy efficiency programs, the preferred portfolio shows a need for incremental demand response programs. The chart to the right in Figure 9.9 compares cumulative demand response program capacity in the 2025 IRP preferred portfolio relative to the 2023 IRP preferred portfolio and does not include capacity from existing programs. The 2025 IRP has a cumulative capacity of demand response programs totaling 515 MW by 2040. By year-end 2045, the 2025 IRP preferred portfolio has a cumulative capacity of demand response programs totaling 789 MW.

[5] A different approach is needed to protect existing customers from sizeable resource and transmission infrastructure investment costs associated with certain new large loads. Consequently, these loads fall outside of the traditional planning process. Should those loads materialize, we are working with certain large customers to ensure they can bring sufficient resources and are prepared to pay for the incremental transmission upgrades required to serve them.

Figure 9.9 – 2025 IRP Preferred Portfolio Energy Efficiency and Demand Response Capacity



[1] Energy efficiency and demand response in the 2023 IRP began escalating two years prior to when escalation begins in the 2025 IRP preferred portfolio. Cumulative energy efficiency and demand response in 2045 in the 2025 IRP preferred portfolio is similar to cumulative energy efficiency and demand response by 2042 in the 2023 IRP, the end of the planning horizon.

Wholesale Power Market Prices and Purchases

Figure 9.11 illustrates that the 2025 IRP's base case forecast for natural gas prices has increased along with an increase in wholesale power prices for most years past 2030 relative to those in the 2023 IRP Update. Prior to 2030, Figure 9.11 reports that the 2025 IRP's base forecast for natural gas and wholesale power prices are lower than those in the 2023 IRP Update. These forecasts are based on prices observed in the forward market and on projections from third-party experts.

Market transactions in the 2025 IRP are purely economic as market purchases do not contribute to capacity like they did in the 2023 IRP and 2023 IRP Update. In the 2023 IRP and 2023 IRP Update, market purchases were limited to 1,000 MW in the winter and 500 MW in the summer. For the 2025 IRP, economic market purchases for energy could be made up to transmission limits, but market purchases were not allowed on the top five load days during peak hours in peak seasons and could never be used for capacity. Refer to Chapter 5: Reliability and Resiliency for additional details.

Figure 9.10 – 2025 IRP Preferred Portfolio Market Purchases

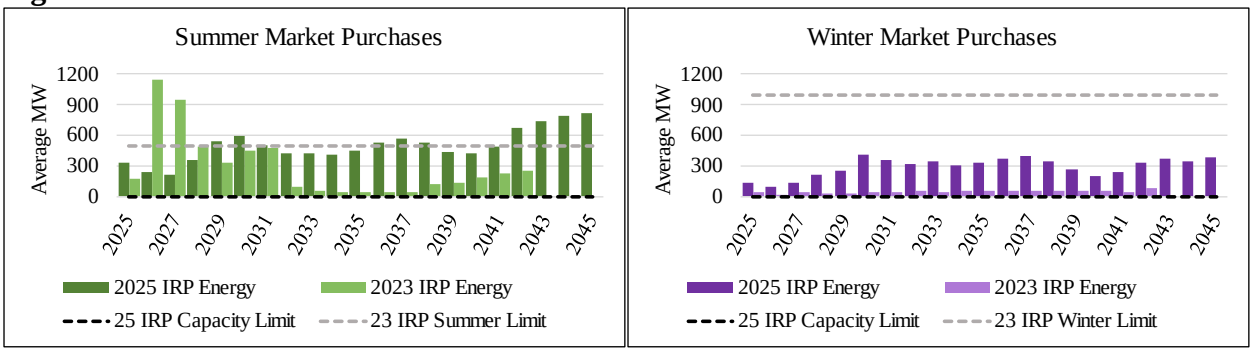
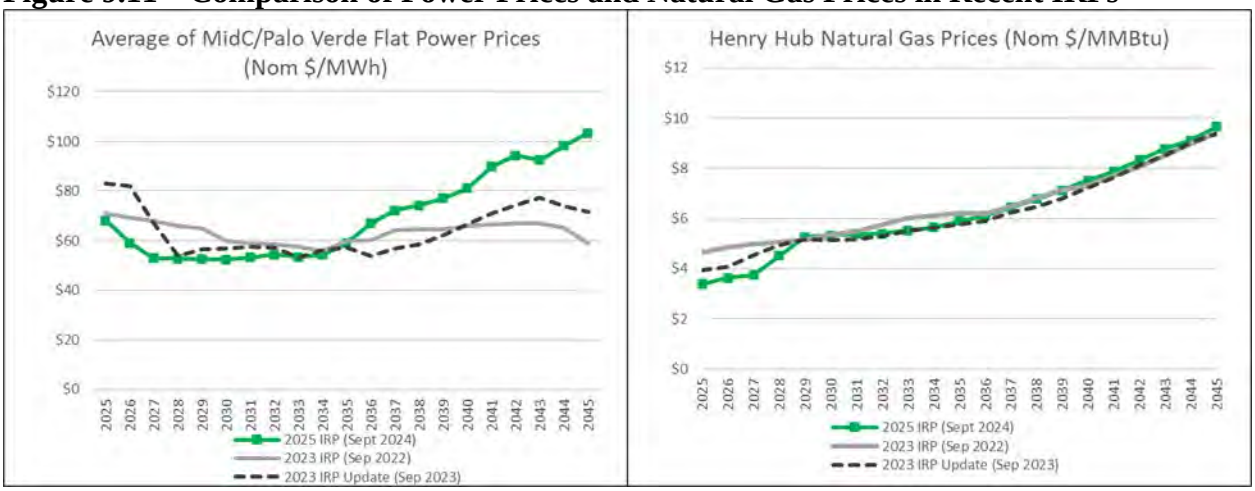


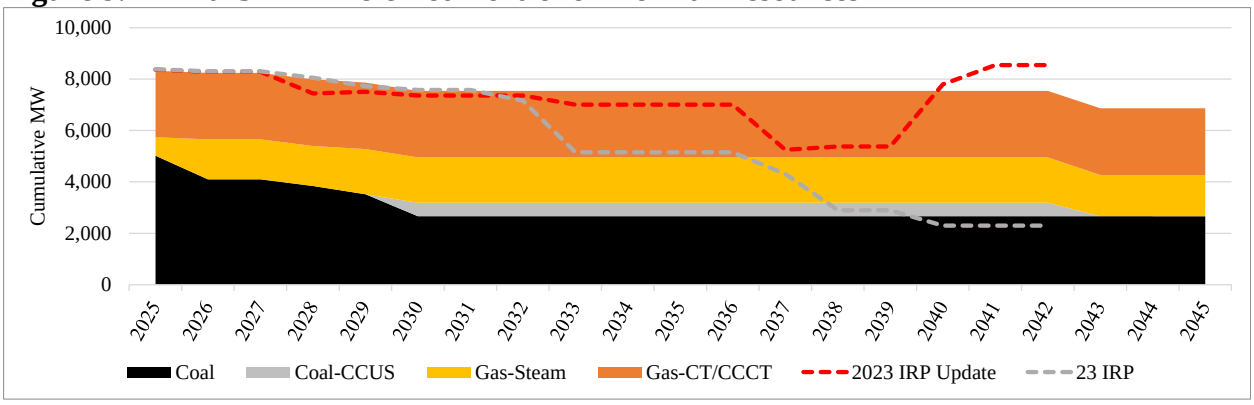
Figure 9.11 – Comparison of Power Prices and Natural Gas Prices in Recent IRPs



Coal and Gas Retirements/Gas Conversions

Coal-fuel plants have been an important contributor to PacifiCorp's resource portfolio for many years. However, there have been material changes in how PacifiCorp has been operating these assets (i.e., by lowering operating minimums and optimizing dispatch through the WEIM) that have enabled the company to reduce fuel consumption, associated costs and emissions, and instead buy increasingly low-cost energy from market participants across the West, which is accessed by our expansive transmission grid. PacifiCorp's coal resources will continue to play a pivotal role in following fluctuations in renewable energy. New for the 2025 IRP, coal-fired units that do not have an enforceable environmental compliance requirement have the option to continue coal-fired operation through the end of the study horizon. Where natural gas supply is expected to be available, an option to convert to natural gas was modeled, and is required for continued operations at units that are required to cease coal-fired operation. As shown in Figure 9.12, the 2025 IRP converts 562 MW of coal-fueled generation to natural gas fueled, exits PacifiCorp's share in 386 MW of minority-owned coal, and also assumes retirements of 220 MW at Dave Johnston and 156 MW of Naughton gas conversion by the end of the study horizon. Jim Bridger Units 3 and 4 convert to carbon capture in 2030 and operate during the 12 years of tax credit eligibility, retiring in 2043. The balance of the coal units continues to operate through the end of the study horizon.

Figure 9.12 – 2025 IRP Preferred Portfolio Thermal Resources



A summary of the coal unit exits, retirements, and conversions in the 2025 IRP preferred portfolio and the 2023 IRP Update preferred portfolio is shown in Table 9.9. Also shown in Table 9.9 are

the coal unit changes which are projected to occur if necessary to comply with the current U.S. Environmental Protection Agency (EPA) greenhouse gas (GHG) emissions regulation under Section 111(d) of the Clean Air Act. In addition to these coal unit exits, retirements, and conversions, the preferred portfolio continues to operate all existing natural gas units through the end of the study horizon.[6]

Table 9.9 – 2025 IRP Coal Resource Results

Majority-Owned Coal			
Unit	2025 IRP Retirement Year		2023 IRP Retirement Year
	Selected w/o 111(d) Regulation	Selected w/ 111(d) Regulation	As Selected
Dave Johnston 1 & 2	Not retired (Gas conversion 2029)	No change	2028
Dave Johnston 3	2027 (Clean air compliance)	No change	2027 (Clean air compliance)
Dave Johnston 4	Not retired	Not retired (Gas conversion 2030)	2039
Hunter 1	Not retired	2032	2031
Hunter 2 & 3	Not retired	Not retired (Alt. fuel conv. 2030)	2032
Huntington 1 & 2	Not retired	Not retired (Alt. fuel conv. 2030)	2032
Jim Bridger 1 & 2	Not retired (Gas conversion 2024)	No change	2037 (Gas conversion 2024)
Jim Bridger 3 & 4	2042 (CCS conversion 2030)	No change	2037 (Gas conversion 2030)
Naughton 1	2042 (Gas conversion 2026)	No change	2036 (Gas conversion 2026)
Naughton 2	Not retired (Gas conversion 2026)	No change	2036 (Gas conversion 2026)
Wyodak	Not retired	2032	2039

Minority-Owned Coal		
Unit	2025 IRP Retirement Year	2023 IRP Retirement Year
	As Input	As Input
Colstrip 3	2025 (Transfer capacity to unit 4)	2025 (Transfer capacity to unit 4)
Colstrip 4	2029 (PacifiCorp exit)	2029 (PacifiCorp exit)
Craig 1	2025 (Assumed end of life)	2025 (Assumed end of life)
Craig 2	2028 (Assumed end of life)	2028 (Assumed end of life)
Hayden 1	2028 (Assumed end of life)	2028 (Assumed end of life)
Hayden 2	2027 (Assumed end of life)	2027 (Assumed end of life)

Carbon Dioxide Equivalent Emissions

The 2025 IRP preferred portfolio reflects PacifiCorp's on-going efforts to provide cost-effective clean-energy solutions for our customers and accordingly reflects an overall declining trajectory of carbon dioxide and other carbon dioxide equivalent emissions resulting in a total (CO_2e) emissions decline. PacifiCorp's emissions have been declining and continue to decline because of several factors including PacifiCorp's participation in the EIM, which reduces customer costs and maximizes use of clean energy; on-going transition to clean-energy resources including new renewable resources, new advanced nuclear resources, new battery storage resources, transmission, and Regional Haze compliance that capitalizes on flexibility.

The chart on the top in Figure 9.13 compares projected annual CO_2e emissions across the 2025 IRP and the 2023 IRP preferred portfolios and is inclusive of emissions attributed to market purchases. In the current 2025 IRP preferred portfolio, emissions are generally higher than projected in the 2023 IRP. This relative increase is primarily the result of two differences in modeling assumptions. In the 2023 IRP, a medium CO2 price was included in the expected price-

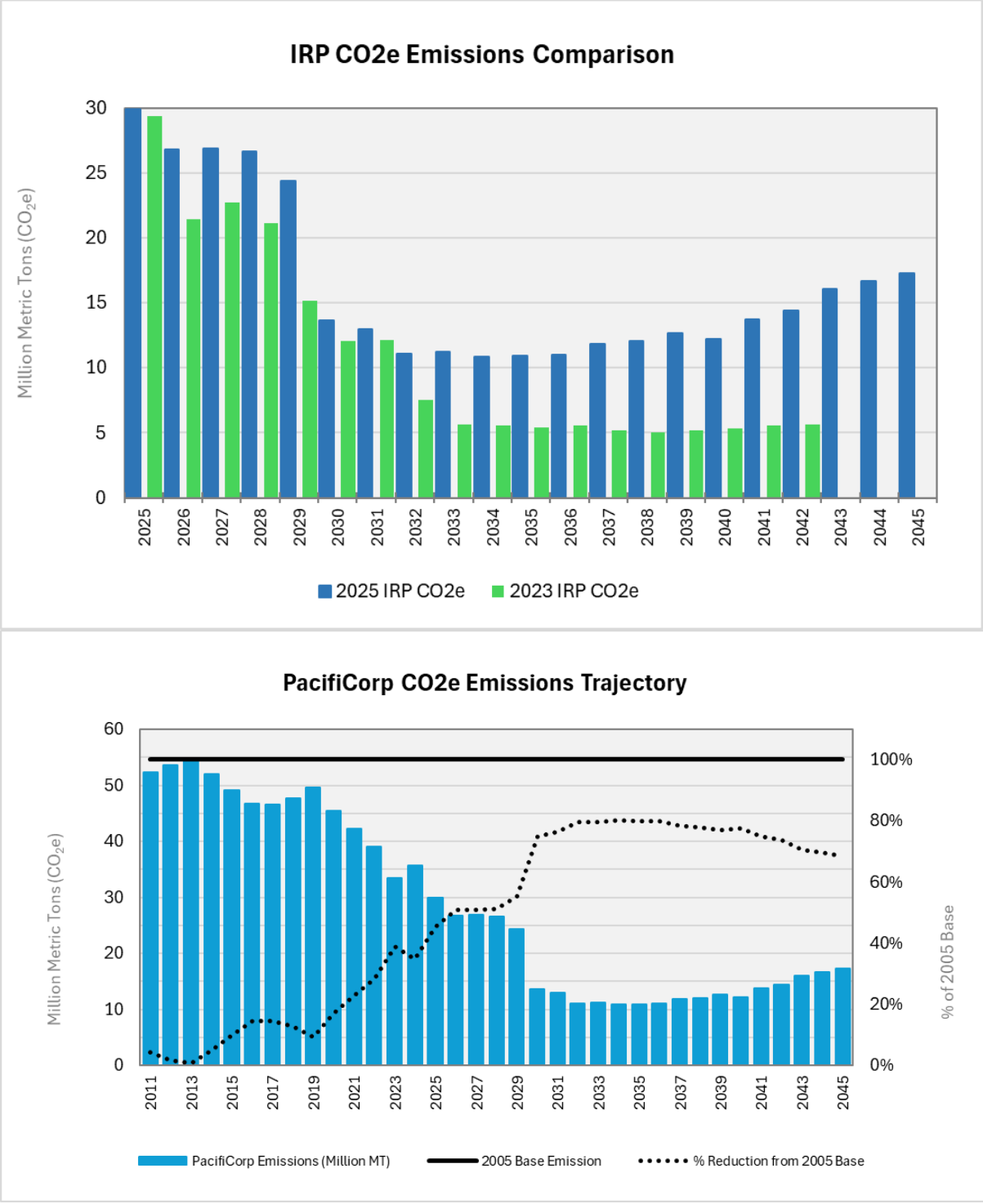
[6] PacifiCorp's Chehalis and Hermiston natural gas units are subject to Washington and Oregon regulation, respectively, and a final determination of state allocations, potential operational restrictions and economics continue to be evaluated.

policy scenario used to forecast emissions. No CO2 price was included in the dispatch of the 2025 IRP preferred portfolio used to forecast emissions. The 2023 IRP also modeled the EPA's proposed implementation of the Ozone Transport Rule as a significant dispatch target on emissions. No dispatch target was included in the expected price-policy scenario used to forecast emissions in the 2025 IRP. The MR (medium gas price with at-risk federal regulation) price-policy scenario accounts for the effects of possible federal policy, and the portfolio optimized and dispatched under the MR price-policy scenario is a better comparison to the 2023 IRP preferred portfolio.

The difference in emissions between the 2023 IRP and the 2025 IRP is also partly due to an increase in unspecified market purchases, which are assigned a default emission factor of 0.428 MT CO2e/MWh. This default factor, often established by state regulations and widely used in GHG compliance reporting across multiple states, remains constant throughout the planning period. However, energy industry experts believe the market is trending toward lower emissions as renewable energy and storage capacity expand. As more renewables enter the market, overall emissions are expected to decline, translating to a lower emission factor. PacifiCorp is actively engaging with states to discuss updating this default emission factor to better reflect the market's transition to cleaner energy. Finally, the difference in emissions from the 2023 IRP reflects the 2025 IRP's balanced strategy to maintaining low-cost firm capacity by allowing existing coal plants to operate through the planning period at a reduced capacity factor. In addition, some coal plants convert to natural gas or install CCS technology. Through these shifts, the overarching trend points to continued emissions reductions, supporting long-term decarbonization goals.

The bottom chart in Figure 9.13 presents historical data and assigns emissions to unspecified market purchases at a rate of 0.428 metric tons CO_2 equivalent per MWh – with no credit to market sales. It also accounts for emissions from specified purchases. The graph shows that system CO2e emissions have declined by approximately 45% in 2025, 75% in 2030, and 77% in 2040, compared to a 2005 baseline of 54.6 million metric tons. In the final five years of the planning horizon, emissions increase moderately due to the factors outlined above.

Figure 9.13 – 2025 IRP Preferred Portfolio CO2 Emissions and PacifiCorp CO2 Equivalent Emissions Trajectory[1]



[1] PacifiCorp CO_2 equivalent emissions trajectory reflects actual emissions through 2023 from owned facilities, specified sources and unspecified sources. 2024 emissions were not forecasted in the 2025 IRP and therefore reflect the forecast from the 2023 IRP Update. From 2025 through the end of the 21-year planning period in 2045, emissions reflect those from the 2025 IRP preferred portfolio with emissions from specified sources reported in CO_2 equivalent. Market purchases are assigned a default emission factor (0.428 metric tons CO_2e/MWh) – emissions from sales are not removed.

Renewable Portfolio Standards

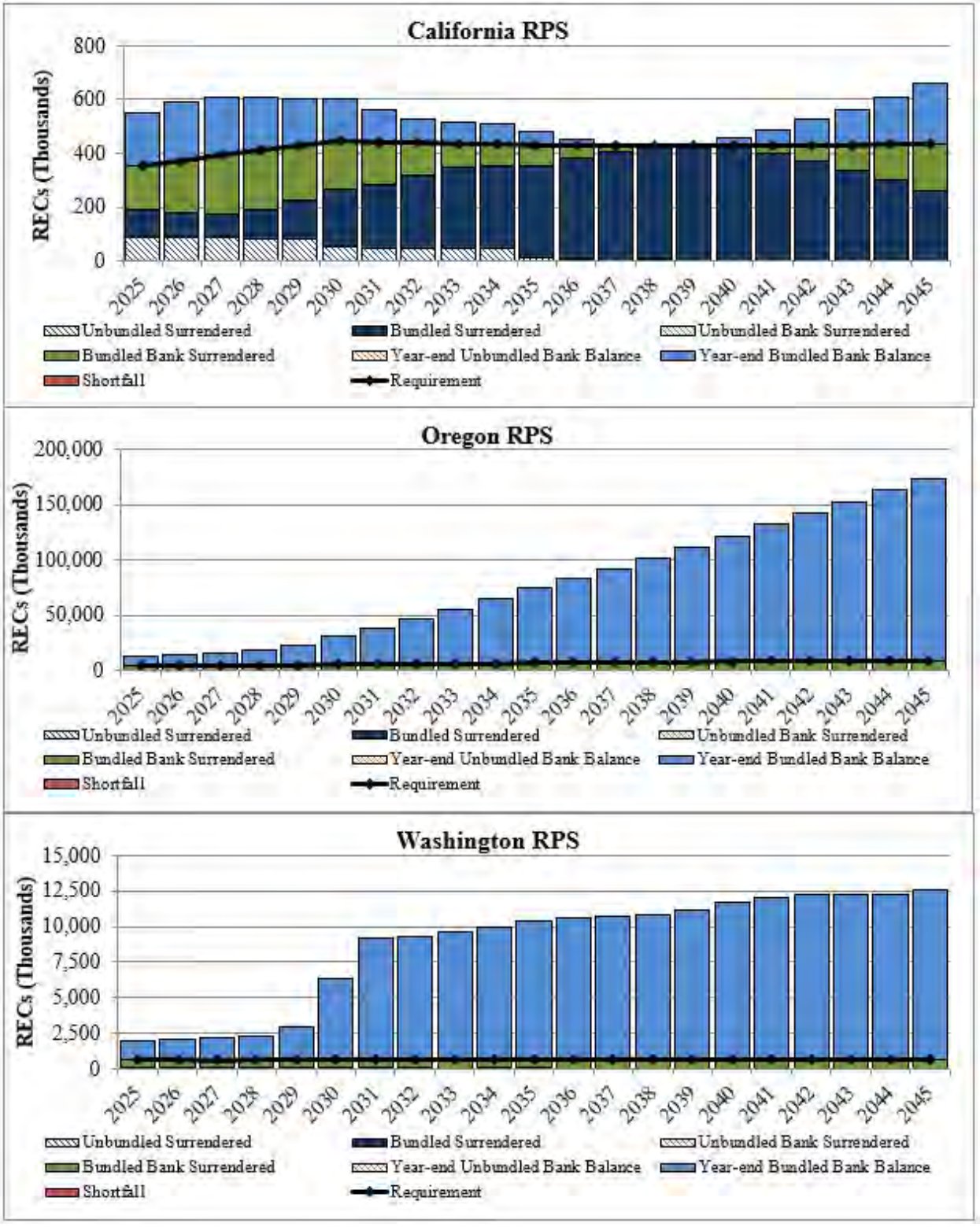
Figure 9.14 shows PacifiCorp's renewable portfolio standard (RPS) compliance forecast for California, Oregon, and Washington after accounting for unbundled REC purchases and new renewable resources in the preferred portfolio. While new resources are included in the preferred portfolio as cost-effective system resources and are not included to specifically meet RPS targets, they nonetheless contribute to meeting RPS targets in PacifiCorp's western states.

Oregon RPS compliance is achieved through 2045 with the addition of new renewable resources. Washington RPS compliance is also achieved through 2045 with the addition of new renewable resources. Under PacifiCorp's 2020 Protocol, and the Washington Interjurisdictional Allocation Methodology, Washington receives a share of renewable resources across PacifiCorp's system; however, Washington may also benefit from the situs allocation of new renewable resources as necessary for compliance.

The California RPS compliance position will be met with owned and contracted renewable resources, as well as unbundled REC purchases at various points throughout the 2025 IRP study period. The increasing RPS requirement results in an increased need for unbundled REC purchases to meet the annual and compliance period targets in the long term. The company will rely on a combination of new renewable resources from the preferred portfolio and unbundled RECs to meet future shortfalls.

Although not depicted in Figure 9.14, PacifiCorp achieves Utah's 2025 state target of supplying 20 percent of adjusted retail sales with eligible renewable resources through a combination of existing owned and contracted resources, along with new renewable resources and transmission included in the 2025 IRP preferred portfolio.

Figure 9.14 – Annual State RPS Compliance Forecast



Oregon HB 2021 Compliance

In 2021, Oregon adopted House Bill 2021, an energy policy seeking to reduce emissions from electric generation facilities used to serve customers in the state. HB 2021 sets targets to reduce emissions associated with Oregon retail sales from a baseline, calculated as the average emissions reported from years 2010 through 2012, by 80 percent in 2030, 90 percent by 2035 and 100 percent by 2040. For PacifiCorp, this requires the company to reduce baseline emissions of 8.99 million metric tons (MMT) of carbon dioxide equivalents (CO_2e) to 1.79 MMT CO_2e by 2030, 0.89 MMT CO_2e by 2035, and zero by 2040. The law also increased Oregon's small-scale renewable energy project purchase requirement from 8 to 10 percent by 2030.

The 2025 IRP preferred portfolio was developed to incorporate resources specifically selected to meet all state-specific requirements, including Oregon's greenhouse gas emission reduction targets defined by HB 2021. PacifiCorp also modeled the small-scale renewable portfolio requirement to ensure that at least 10 percent of Oregon-allocated capacity will be small-scale (20 MW or less), in each year from 2030 onwards. For more information on Oregon's planning requirements and the compliance position of the preferred portfolio, refer to Volume II, Appendix P (Oregon Clean Energy Update).

Capacity and Energy

Figure 9.15 and Figure 9.16 show how PacifiCorp's system energy and nameplate capacity mix is projected to change over time. In developing these figures, purchased power is reported in identifiable resource categories where possible. Energy mix figures are based upon dispatch under base price curve assumptions. Renewable capacity and generation reflect categorization by technology type and not disposition of renewable energy attributes for regulatory compliance requirements.[7] On an energy basis, coal generation drops below 20 percent in 2030 and remains below 15 percent through the end of the planning period. On a capacity basis, coal resources drop below 10 percent by the end of the planning period. Reduced energy and capacity from coal is offset primarily by increased energy and capacity from renewable and storage resources, nuclear resources, and DSM resources.

[7]The projected PacifiCorpIRP preferred portfolio "energy mix" is based on energy production and not resource capability, capacity or delivered energy. All or some of the renewable energy attributes associated with wind, biomass, geothermal and qualifying hydro facilities in PacifiCorp's energy mix may be: (a) used in future years to comply with renewable portfolio standards or other regulatory requirements; (b) sold to third parties in the form of renewable energy credits or other environmental commodities; or (c) excluded from energy purchased. PacifiCorp'sIRP preferred portfolio energy mix includes owned resources and purchases from third parties.

Figure 9.15 – Projected Energy Mix with Preferred Portfolio Resources

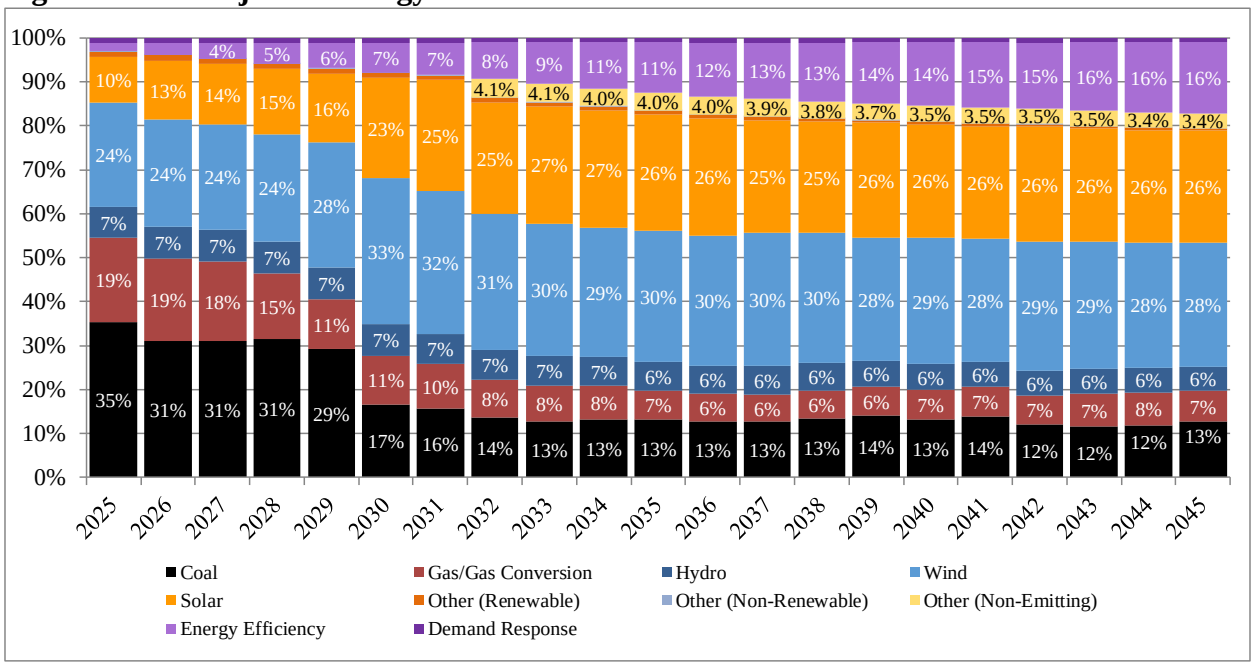
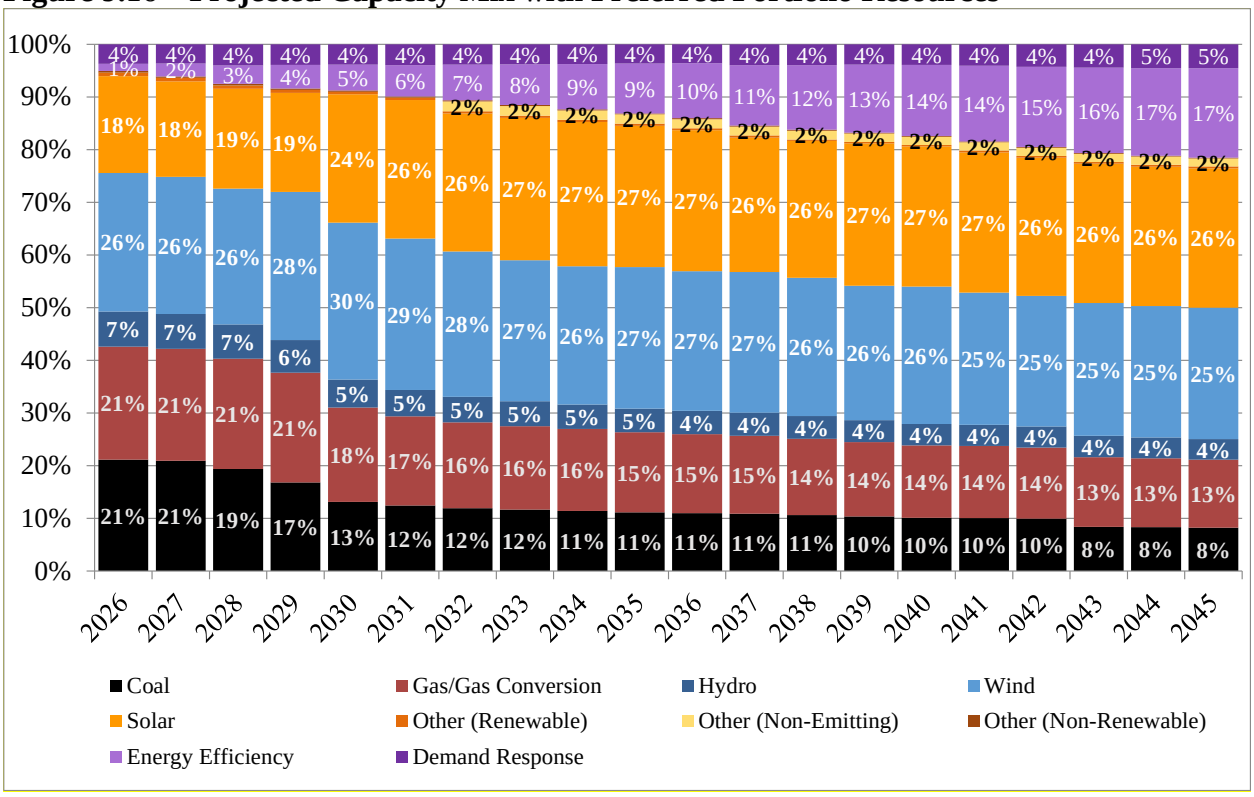


Figure 9.16 – Projected Capacity Mix with Preferred Portfolio Resources



Detailed Preferred Portfolio

Table 9.10 provides line-item detail of PacifiCorp's 2025 IRP preferred portfolio showing new resource capacity along with changes in existing resource capacity through the 21-year planning horizon. Table 9.11 shows jurisdictional resource selections of PacifiCorp's 2025 IRP preferred portfolio. Table 9.12 and Table 9.13 report line-item detail of PacifiCorp's peak load and resource capacity balance for summer, including preferred portfolio resources, over the 21-year planning horizon. Table 9.14 and Table 9.15 report line-item detail of PacifiCorp's peak load and resource capacity balance for winter, including preferred portfolio resources, over the 21-year horizon.

Table 9.10 – PacifiCorp's 2025 IRP Preferred Portfolio

Summary Portfolio Capacity by Resource Type and Year, Installed MW																						
	Installed Capacity, MW																					
Resource	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Expansion Options																						
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	500
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19	-	4	-	18	41
DSM - Energy Efficiency	92	89	209	220	239	261	329	291	299	295	299	315	347	314	293	301	303	315	238	205	182	5,436
DSM - Demand Response	18	2	-	63	21	120	99	5	1	3	3	21	112	18	5	24	61	106	29	26	52	789
Renewable - Wind	-	-	-	21	794	1,452	344	1	-	29	347	40	175	37	-	376	50	-	20	-	96	3,782
Renewable - Small Scale Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar	-	-	-	222	180	1,690	849	240	403	225	13	-	1	-	554	104	12	-	-	197	75	4,765
Renewable - Small Scale Solar	-	-	-	-	-	320	2	18	26	21	30	132	-	309	-	-	110	-	-	143	36	1,147
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery, < 8 hour	-	-	-	1,146	242	296	-	119	39	210	20	47	-	175	67	113	67	713	5	459	733	4,451
Renewable - Battery, 8-23 hour	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery, 24+ hour	-	-	-	-	-	511	91	3	4	3	4	4	11	83	37	939	107	319	402	197	358	3,073
Other Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Existing Unit Changes																						
Coal Plant Retirements - Minority Owned	-	(82)	-	(33)	(123)	(148)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(386)
Coal Plant Retirements	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)
Coal Plant Ceases as Coal	-	(357)	-	-	(205)	(700)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,262)
Coal - CCS	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	(526)	-	-	0
Coal - Gas Conversions	-	357	-	-	205	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	406
Gas Plant Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Non-Thermal	-	-	-	-	-	-	-	-	-	(3)	-	-	-	(32)	-	-	-	-	-	-	-	(35)
Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Wind PPA	-	(64)	-	-	-	(99)	(200)	-	-	-	-	-	-	-	-	-	(333)	-	-	-	-	(696)
Expire - Solar PPA	-	-	-	(2)	-	-	(9)	-	-	-	-	-	(100)	-	-	-	(65)	-	-	(230)	-	(407)
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(47)	(3)	-	(50)
Expire - Other	-	520	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	500
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**110**	**464**	**209**	**1,417**	**1,353**	**4,229**	**1,505**	**1,177**	**772**	**783**	**716**	**559**	**546**	**904**	**956**	**1,857**	**331**	**1,453**	**(31)**	**994**	**1,530**	

Table 9.11 – Preferred Portfolio with Jurisdictional Resource Selections

	Installed Capacity, MW																					
Resource	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**Total**
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	**500**	-	-	-	-	-	-	-	-	-	-	-	-	-	**500**
OR	-	-	-	-	-	-	-	130	-	-	-	-	-	-	-	-	-	-	-	-	-	130
WA	-	-	-	-	-	-	-	32	-	-	-	-	-	-	-	-	-	-	-	-	-	32
UIWC	-	-	-	-	-	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	338
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**19**	-	**4**	-	**18**	**41**
OR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19	-	4	-	18	40
WA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
UIWC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	**92**	**89**	**209**	**220**	**239**	**261**	**329**	**291**	**299**	**295**	**299**	**315**	**347**	**314**	**293**	**301**	**303**	**315**	**238**	**205**	**182**	**5,255**
OR	-	-	97	101	107	114	115	110	113	108	109	111	110	106	102	116	123	107	114	92	90	2,044
WA	-	0	13	16	15	17	18	18	19	19	20	19	19	15	14	12	11	11	10	8	7	280
UIWC	-	0	99	103	117	130	196	163	167	168	170	185	218	193	177	172	170	197	114	106	86	2,931
DSM - Demand Response	**18**	**2**	-	**63**	**21**	**120**	**99**	**5**	**1**	**3**	**3**	**21**	**112**	**18**	**5**	**24**	**61**	**106**	**29**	**26**	**52**	**769**
OR	-	0	-	48	16	7	-	5	1	3	3	11	-	11	4	23	4	-	9	-	8	153
WA	-	0	-	15	2	2	-	-	-	-	-	8	-	6	1	1	1	-	1	-	14	51
UIWC	-	1	-	-	2	111	99	-	-	-	-	2	112	-	-	0	57	106	19	26	30	566
Renewable - Wind	-	-	-	**21**	**794**	**1,452**	**344**	**1**	-	**29**	**347**	**40**	**175**	**37**	-	**376**	**50**	-	**20**	-	**96**	**3,782**
OR	-	-	-	16	445	939	-	1	-	22	260	30	131	28	0	282	37	-	15	-	72	2,278
WA	-	-	-	5	148	313	-	-	-	7	87	10	44	9	0	94	12	-	5	-	24	758
UIWC	-	-	-	-	200	200	344	-	-	-	-	-	0	-	-	-	-	-	-	-	-	744
Renewable - Small Scale Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar	-	-	-	**222**	**180**	**1,690**	**849**	**240**	**403**	**225**	**13**	-	**1**	-	**554**	**104**	**12**	-	-	**197**	**75**	**4,765**
OR	-	-	-	167	135	1,268	136	180	302	169	10	-	0	0	416	78	9	-	-	148	56	3,074
WA	-	-	-	56	45	423	45	60	101	56	3	-	0	0	139	26	3	-	-	49	19	1,025
UIWC	-	-	-	-	-	-	668	-	-	-	-	-	0	-	-	-	-	-	-	-	-	668
Renewable - Small Scale Solar	-	-	-	-	-	**320**	**2**	**18**	**26**	**21**	**30**	**132**	-	**309**	-	-	**110**	-	-	**143**	**36**	**1,147**
OR	-	-	-	-	-	320	2	18	26	21	30	132	0	309	-	-	110	-	-	143	36	1,147
WA	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	0
UIWC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery, < 8 hour	-	-	-	**1,146**	**242**	**296**	-	**119**	**39**	**210**	**20**	**47**	-	**175**	**67**	**113**	**67**	**713**	**5**	**459**	**733**	**4,451**
OR	-	-	1	280	100	128	-	119	39	210	20	47	-	46	-	107	55	-	-	-	-	1,152
WA	-	-	-	865	114	168	-	-	-	-	-	-	-	129	67	7	12	-	5	-	-	1,367
UIWC	-	-	1	-	27	-	-	-	-	-	-	-	0	-	-	-	-	713	-	459	733	1,933
Renewable - Battery, 8-23 hour	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery, 24+ hour	-	-	-	-	-	**511**	**91**	**3**	**4**	**3**	**4**	**4**	**11**	**83**	**37**	**939**	**107**	**319**	**402**	**197**	**358**	**3,073**
OR	-	-	-	-	-	272	88	-	-	-	-	-	7	79	33	934	102	210	397	192	353	2,667
WA	-	-	-	-	-	238	3	3	4	3	4	4	4	4	4	4	4	5	5	5	5	298
UIWC	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	104	-	-	-	105
Other Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Table 9.12 – Preferred Portfolio Summer Capacity Load and Resource Balance (2025-2034)

East	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	3,960	3,567	3,567	3,375	3,090	2,926	2,926	2,926	2,926	2,926
Gas	2,984	3,294	3,294	3,294	3,469	3,469	3,469	3,469	3,469	3,469
Hydroelectric	76	76	76	76	76	76	76	76	76	76
Wind	587	613	596	578	561	534	503	487	470	453
Solar	342	499	487	475	463	452	440	428	416	404
Other Renewable	46	45	44	42	41	40	39	37	36	35
Storage	1	939	925	909	894	879	865	849	834	819
Purchase	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	405	394	383	372	361	351	340	328	314	301
Demand Response	451	446	440	452	450	443	429	423	431	425
Sale	0	0	0	0	0	0	0	0	0	0
Transfers	(281)	(1,447)	(1,369)	(1,105)	(973)	0	0	0	0	0
East Existing Resources	**8,571**	**8,426**	**8,443**	**8,470**	**8,433**	**9,171**	**9,087**	**9,024**	**8,973**	**8,909**
Additional Proxy/Short-Term Purchases	0	0	0	0	0	0	0	0	0	0
Hydrogen Storage Peaker	0	0	0	0	0	0	0	0	0	0
Gas	0	0	0	0	2	2	2	2	2	2
Wind	0	0	0	0	35	68	124	121	119	117
Solar	0	0	0	0	0	0	151	147	143	139
Storage	0	0	2	2	25	27	27	27	26	26
Nuclear	0	0	0	0	0	0	0	457	454	452
Demand Response	7	7	7	7	8	80	151	149	146	143
East Planned Resources	**7**	**7**	**9**	**9**	**70**	**177**	**455**	**903**	**891**	**879**
East Total Resources	**8,578**	**8,433**	**8,452**	**8,479**	**8,504**	**9,348**	**9,542**	**9,927**	**9,863**	**9,788**
Load	7,746	7,655	7,781	7,919	8,068	8,234	8,447	8,609	8,528	8,700
Distributed Generation	(157)	(143)	(186)	(234)	(285)	(341)	(400)	(458)	(321)	(354)
Energy Efficiency	(91)	(141)	(206)	(274)	(349)	(428)	(520)	(631)	(696)	(801)
East Total obligation	**7,498**	**7,372**	**7,388**	**7,412**	**7,433**	**7,465**	**7,527**	**7,520**	**7,511**	**7,545**
East Reserve Margin	14.4%	14.4%	14.4%	14.4%	14.4%	25.2%	26.8%	32.0%	31.3%	29.7%
West										
Coal	133	133	133	133	133	0	0	0	0	0
Gas	716	716	716	716	716	716	716	716	716	716
Hydroelectric	712	712	712	712	712	712	712	712	712	712
Wind	74	72	70	67	65	63	61	59	57	54
Solar	69	67	65	62	60	58	52	50	48	46
Other Renewable	0	0	0	0	0	0	0	0	0	0
Storage	2	1	1	1	1	1	1	1	1	0
Purchase	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	232	226	215	209	200	194	187	179	174	170
Demand Response	60	59	58	57	57	56	55	54	54	53
Sale	0	0	0	0	0	0	0	0	0	0
Transfers	281	1,447	1,369	1,105	973	0	0	0	0	0
West Existing Resources	**2,277**	**3,433**	**3,339**	**3,063**	**2,916**	**1,800**	**1,784**	**1,771**	**1,761**	**1,751**
Additional Proxy/Short-Term Purchases	1,910	757	885	0	0	0	0	0	0	0
Hydrogen Storage Peaker	0	0	0	0	0	0	0	0	0	0
Gas	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	2	67	202	201	201	200	202
Solar	0	0	0	117	205	1,185	1,231	1,306	1,446	1,496
Storage	0	0	1	839	982	1,684	1,759	1,828	1,841	1,969
Nuclear	0	0	0	0	0	0	0	0	0	0
Demand Response	2	2	2	2	2	2	2	2	2	2
West Planned Resources	**1,911**	**759**	**889**	**960**	**1,255**	**3,072**	**3,193**	**3,336**	**3,488**	**3,668**
West Total Resources	**4,189**	**4,192**	**4,227**	**4,022**	**4,171**	**4,872**	**4,977**	**5,107**	**5,249**	**5,419**
Load	3,778	3,812	3,905	3,967	4,032	4,103	4,239	4,255	4,288	4,376
Distributed Generation	(49)	(54)	(75)	(99)	(124)	(152)	(182)	(213)	(132)	(148)
Energy Efficiency	(67)	(94)	(135)	(178)	(220)	(263)	(318)	(359)	(389)	(431)
West Total obligation	**3,662**	**3,664**	**3,695**	**3,690**	**3,688**	**3,688**	**3,738**	**3,684**	**3,767**	**3,798**
West Reserve Margin	14.4%	14.4%	14.4%	9.0%	13.1%	32.1%	33.1%	38.6%	39.4%	42.7%
System										
Total Resources	12,767	12,625	12,680	12,501	12,675	14,220	14,518	15,034	15,113	15,207
Obligation	11,160	11,036	11,084	11,102	11,121	11,153	11,265	11,203	11,278	11,343
Planning Reserves (14.4%)	1,607	1,589	1,596	1,599	1,601	1,606	1,622	1,613	1,624	1,633
Obligation + Reserves	12,767	12,625	12,680	12,701	12,723	12,759	12,887	12,817	12,902	12,977
System Position	0	0	0	(199)	(48)	1,461	1,631	2,217	2,211	2,231
Reserve Margin	**14.4%**	**14.4%**	**14.4%**	**12.6%**	**14.0%**	**27.5%**	**28.9%**	**34.2%**	**34.0%**	**34.1%**

Table 9.13 – Preferred Portfolio Summer Capacity Load and Resource Balance (2036-2045)

East	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	2,926	2,926	2,926	2,926	2,926	2,926	2,926	2,926	2,432	2,432	2,432
Gas	3,469	3,469	3,469	3,469	3,469	3,469	3,469	3,469	3,322	3,322	3,322
Hydroelectric	76	76	76	76	76	76	76	76	76	76	76
Wind	437	421	404	387	371	355	308	293	278	263	249
Solar	392	381	340	329	319	308	297	286	276	243	233
Other Renewable	33	32	31	12	11	10	10	9	9	8	0
Storage	804	788	773	759	744	728	714	699	684	668	654
Purchase	0	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	291	269	221	212	203	192	184	176	169	162	155
Demand Response	422	401	402	398	400	406	398	375	376	389	351
Sale	0	0	0	0	0	0	0	0	0	0	0
Transfers	0	0	0	0	0	0	0	0	0	0	0
East Existing Resources	**8,851**	**8,763**	**8,643**	**8,569**	**8,519**	**8,472**	**8,383**	**8,310**	**7,622**	**7,564**	**7,472**
Additional Proxy/Short-Term Purchas	0	0	0	0	0	0	64	0	672	628	475
Hydrogen Storage Peaker	0	0	0	0	0	0	0	0	0	0	0
Gas	2	2	3	3	3	3	3	3	3	3	3
Wind	115	112	110	108	106	104	101	99	97	95	92
Solar	135	131	127	123	120	116	111	107	104	100	96
Storage	26	25	25	25	24	24	23	592	581	858	1,289
Nuclear	450	447	445	442	440	437	435	432	430	427	426
Demand Response	141	138	197	193	189	186	209	253	257	264	270
East Planned Resources	**868**	**856**	**907**	**895**	**882**	**869**	**947**	**1,487**	**2,144**	**2,373**	**2,650**
East Total Resources	**9,719**	**9,620**	**9,550**	**9,464**	**9,401**	**9,340**	**9,330**	**9,797**	**9,766**	**9,937**	**10,123**
Load	8,893	9,150	9,349	9,567	9,774	9,993	10,214	10,478	10,693	10,891	11,097
Distributed Generation	(385)	(415)	(445)	(474)	(503)	(529)	(557)	(584)	(609)	(635)	(660)
Energy Efficiency	(911)	(983)	(1,112)	(1,227)	(1,325)	(1,407)	(1,501)	(1,482)	(1,547)	(1,570)	(1,588)
East Total obligation	**7,596**	**7,752**	**7,792**	**7,865**	**7,946**	**8,057**	**8,156**	**8,413**	**8,536**	**8,686**	**8,848**
East Reserve Margin	27.9%	24.1%	22.6%	20.3%	18.3%	15.9%	14.4%	16.5%	14.4%	14.4%	14.4%
West											
Coal	0	0	0	0	0	0	0	0	0	0	0
Gas	716	716	716	716	716	716	716	716	716	716	716
Hydroelectric	712	712	712	712	712	712	712	712	712	712	712
Wind	52	50	48	46	44	41	39	37	35	33	31
Solar	45	43	41	39	37	35	13	12	11	11	10
Other Renewable	0	0	0	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0	0	0	0
Purchase	0	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	165	160	142	138	132	128	124	120	101	97	95
Demand Response	52	51	51	50	49	48	48	47	46	45	44
Sale	0	0	0	0	0	0	0	0	0	0	0
Transfers	0	0	0	0	0	0	0	0	0	0	0
West Existing Resources	**1,741**	**1,731**	**1,708**	**1,700**	**1,689**	**1,681**	**1,651**	**1,644**	**1,621**	**1,613**	**1,608**
Additional Proxy/Short-Term Purchas	0	0	0	0	0	0	0	0	0	0	0
Hydrogen Storage Peaker	0	0	0	0	0	0	0	0	0	0	0
Gas	0	0	0	0	0	0	0	0	0	0	0
Wind	238	241	259	262	261	299	303	302	303	302	310
Solar	1,455	1,446	1,383	1,431	1,553	1,510	1,470	1,387	1,307	1,314	1,255
Storage	1,966	1,980	1,971	2,144	2,200	3,176	3,299	3,487	3,863	4,035	4,365
Nuclear	0	0	0	0	0	0	0	0	0	0	0
Demand Response	2	3	3	3	3	3	3	3	3	3	8
West Planned Resources	**3,660**	**3,670**	**3,616**	**3,840**	**4,016**	**4,988**	**5,075**	**5,179**	**5,476**	**5,654**	**5,938**
West Total Resources	**5,401**	**5,401**	**5,325**	**5,540**	**5,705**	**6,668**	**6,727**	**6,823**	**7,097**	**7,267**	**7,545**
Load	4,475	4,577	4,692	4,807	4,927	5,049	5,173	5,376	5,430	5,553	5,680
Distributed Generation	(163)	(177)	(192)	(206)	(221)	(234)	(249)	(263)	(277)	(290)	(304)
Energy Efficiency	(471)	(515)	(571)	(603)	(634)	(661)	(691)	(774)	(591)	(599)	(612)
West Total obligation	**3,841**	**3,885**	**3,929**	**3,998**	**4,073**	**4,154**	**4,233**	**4,340**	**4,562**	**4,663**	**4,764**
West Reserve Margin	40.6%	39.0%	35.5%	38.6%	40.1%	60.5%	58.9%	57.2%	55.6%	55.9%	58.4%
System											
Total Resources	15,120	15,021	14,875	15,003	15,106	16,009	16,057	16,620	16,863	17,205	17,668
Obligation	11,438	11,637	11,721	11,863	12,019	12,211	12,388	12,753	13,099	13,349	13,612
Planning Reserves (14.4%)	1,647	1,676	1,688	1,708	1,731	1,758	1,784	1,836	1,886	1,922	1,960
Obligation + Reserves	13,085	13,313	13,409	13,572	13,750	13,969	14,172	14,589	14,985	15,272	15,573
System Position	2,036	1,709	1,465	1,432	1,357	2,040	1,885	2,031	1,878	1,933	2,095
Reserve Margin	**32.2%**	**29.1%**	**26.9%**	**26.5%**	**25.7%**	**31.1%**	**29.6%**	**30.3%**	**28.7%**	**28.9%**	**29.8%**

Table 9.14 – Preferred Portfolio Winter Capacity Load and Resource Balance (2025-2034)

East	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	4,147	3,734	3,734	3,499	3,185	3,015	3,015	3,015	3,015	3,015
Gas	3,003	3,334	3,334	3,335	3,526	3,527	3,527	3,527	3,527	3,527
Hydroelectric	33	33	33	33	33	33	33	33	33	33
Wind	1,837	1,957	1,892	1,829	1,766	1,657	1,523	1,463	1,404	1,346
Solar	38	104	101	98	95	92	89	85	82	79
Other Renewable	41	39	38	37	35	34	33	32	30	29
Storage	1	621	606	591	576	561	546	531	516	500
Purchase	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	186	181	176	171	166	161	156	149	140	124
Demand Response	119	118	118	128	129	128	121	120	128	127
Sale	0	0	0	0	0	0	0	0	0	0
Transfers	(1,600)	(1,600)	(1,600)	(1,226)	(930)	0	0	0	0	0
East Existing Resources	**7,804**	**8,523**	**8,433**	**8,495**	**8,581**	**9,208**	**9,042**	**8,954**	**8,875**	**8,780**
Additional Proxy/Short-Term Purchases	0	0	0	0	0	0	0	0	0	0
Hydrogen Storage Peaker	0	0	0	0	0	0	0	0	0	0
Gas	0	0	0	0	2	2	2	2	2	2
Wind	0	0	0	0	90	175	316	306	297	287
Solar	0	0	0	0	0	0	39	37	36	35
Storage	0	0	1	1	17	18	18	18	18	17
Nuclear	0	0	0	0	0	0	0	403	401	398
Demand Response	0	0	0	0	0	0	0	0	0	0
East Planned Resources	**0**	**0**	**2**	**2**	**109**	**196**	**374**	**767**	**754**	**740**
East Total Resources	**7,804**	**8,523**	**8,435**	**8,496**	**8,689**	**9,404**	**9,417**	**9,722**	**9,629**	**9,520**
Load	5,898	5,911	6,036	6,164	6,278	6,408	6,569	6,706	6,899	7,084
Distributed Generation	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Energy Efficiency	(75)	(118)	(157)	(197)	(239)	(283)	(331)	(388)	(450)	(513)
East Total obligation	**5,821**	**5,790**	**5,876**	**5,963**	**6,033**	**6,119**	**6,231**	**6,309**	**6,440**	**6,560**
East Reserve Margin	34.1%	47.2%	43.5%	42.5%	44.0%	53.7%	51.1%	54.1%	49.5%	45.1%
West										
Coal	147	147	147	147	147	0	0	0	0	0
Gas	735	735	735	735	735	735	735	735	735	735
Hydroelectric	726	726	726	726	726	726	726	726	726	726
Wind	64	62	59	57	55	53	51	49	47	45
Solar	1	1	1	1	1	1	0	0	0	0
Other Renewable	0	0	0	0	0	0	0	0	0	0
Storage	2	2	2	2	2	2	2	2	2	0
Purchase	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	70	69	62	61	58	57	57	56	56	56
Demand Response	0	0	0	0	0	0	0	0	0	0
Sale	0	0	0	0	0	0	0	0	0	0
Transfers	1,600	1,600	1,600	1,226	930	0	0	0	0	0
West Existing Resources	**3,345**	**3,342**	**3,333**	**2,956**	**2,655**	**1,574**	**1,571**	**1,568**	**1,566**	**1,561**
Additional Proxy/Short-Term Purchases	0	0	0	0	0	0	0	0	0	0
Hydrogen Storage Peaker	0	0	0	0	0	0	0	0	0	0
Gas	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	2	67	201	201	200	199	202
Solar	0	0	0	30	52	299	309	326	359	368
Storage	0	0	1	1,091	1,276	2,037	2,104	2,193	2,206	2,369
Nuclear	0	0	0	0	0	0	0	0	0	0
Demand Response	0	0	0	41	51	56	55	58	58	59
West Planned Resources	**0**	**0**	**2**	**1,164**	**1,446**	**2,594**	**2,669**	**2,776**	**2,821**	**2,997**
West Total Resources	**3,345**	**3,342**	**3,335**	**4,120**	**4,101**	**4,168**	**4,240**	**4,344**	**4,387**	**4,559**
Load	3,511	3,571	3,640	3,701	3,741	3,805	3,904	3,981	4,068	4,160
Distributed Generation	(0)	(0)	(1)	(1)	(1)	(1)	(1)	(2)	(2)	(2)
Energy Efficiency	(52)	(65)	(118)	(173)	(229)	(286)	(345)	(401)	(457)	(511)
West Total obligation	**3,459**	**3,506**	**3,521**	**3,527**	**3,511**	**3,517**	**3,558**	**3,578**	**3,609**	**3,647**
West Reserve Margin	-3.3%	-4.7%	-5.3%	16.8%	16.8%	18.5%	19.2%	21.4%	21.5%	25.0%
System										
Total Resources	11,149	11,865	11,769	12,616	12,790	13,572	13,657	14,066	14,016	14,079
Obligation	9,281	9,296	9,397	9,490	9,544	9,636	9,789	9,888	10,049	10,207
Planning Reserves (16.8%)	1,559	1,562	1,579	1,594	1,603	1,619	1,645	1,661	1,688	1,715
Obligation + Reserves	10,840	10,858	10,975	11,084	11,147	11,255	11,434	11,549	11,738	11,922
System Position	309	1,008	794	1,532	1,643	2,317	2,223	2,517	2,278	2,157
Reserve Margin	**20.1%**	**27.6%**	**25.2%**	**32.9%**	**34.0%**	**40.8%**	**39.5%**	**42.3%**	**39.5%**	**37.9%**

Table 9.15 – Preferred Portfolio Winter Capacity Load and Resource Balance (2035-2045)

East	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	3,015	3,015	3,015	3,015	3,015	3,015	3,015	3,015	2,503	2,503	2,503
Gas	3,527	3,527	3,527	3,527	3,527	3,527	3,527	3,527	3,378	3,378	3,378
Hydroelectric	33	33	33	33	33	33	33	33	33	33	33
Wind	1,285	1,226	1,168	1,107	1,049	990	850	797	744	689	636
Solar	76	73	70	67	64	61	58	55	52	42	39
Other Renewable	28	26	25	9	8	8	7	7	6	6	0
Storage	485	470	455	440	425	410	395	379	365	350	334
Purchase	0	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	120	112	99	94	90	86	82	78	75	71	67
Demand Response	128	117	121	121	125	132	129	117	121	132	109
Sale	0	0	0	0	0	0	0	0	0	0	0
Transfers	0	0	0	0	0	0	0	0	0	0	0
East Existing Resources	**8,697**	**8,600**	**8,511**	**8,412**	**8,336**	**8,262**	**8,096**	**8,008**	**7,276**	**7,204**	**7,101**
Additional Proxy/Short-Term Purchas	0	0	0	0	0	0	0	0	0	0	0
Hydrogen Storage Peaker	0	0	0	0	0	0	0	0	0	0	0
Gas	2	2	3	3	3	3	3	3	3	3	3
Wind	278	268	259	250	240	231	221	212	202	193	183
Solar	33	32	31	30	28	27	26	25	23	22	21
Storage	17	16	16	16	15	15	14	370	360	499	711
Nuclear	396	394	392	389	387	384	381	379	377	374	372
Demand Response	0	0	0	0	0	0	0	0	0	0	1
East Planned Resources	**727**	**713**	**700**	**687**	**673**	**660**	**645**	**988**	**965**	**1,091**	**1,291**
East Total Resources	**9,423**	**9,313**	**9,212**	**9,099**	**9,009**	**8,921**	**8,742**	**8,996**	**8,241**	**8,294**	**8,392**
Load	7,248	7,421	7,645	7,863	8,087	8,287	8,466	8,705	8,909	9,134	9,224
Distributed Generation	(11)	(11)	(12)	(13)	(13)	(14)	(14)	(14)	(15)	(15)	(16)
Energy Efficiency	(579)	(624)	(700)	(766)	(826)	(886)	(954)	(973)	(1,022)	(1,049)	(1,077)
East Total obligation	**6,659**	**6,786**	**6,932**	**7,084**	**7,248**	**7,387**	**7,498**	**7,717**	**7,872**	**8,070**	**8,131**
East Reserve Margin	41.5%	37.2%	32.9%	28.4%	24.3%	20.8%	16.6%	16.6%	4.7%	2.8%	3.2%
West											
Coal	0	0	0	0	0	0	0	0	0	0	0
Gas	735	735	735	735	735	735	735	735	735	735	735
Hydroelectric	726	726	726	726	726	726	726	726	726	726	726
Wind	42	40	38	36	34	32	30	28	25	23	21
Solar	0	0	0	0	0	0	0	0	0	0	0
Other Renewable	0	0	0	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0	0	0	0
Purchase	0	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	55	54	53	53	51	51	50	50	50	49	49
Demand Response	0	0	0	0	0	0	0	0	0	0	0
Sale	0	0	0	0	0	0	0	0	0	0	0
Transfers	0	0	0	0	0	0	0	0	0	0	0
West Existing Resources	**1,559**	**1,555**	**1,552**	**1,550**	**1,546**	**1,544**	**1,541**	**1,539**	**1,536**	**1,534**	**1,531**
Additional Proxy/Short-Term Purchas	0	0	0	0	0	0	0	0	0	0	0
Hydrogen Storage Peaker	0	0	0	0	0	0	0	0	0	0	0
Gas	0	0	0	0	0	0	0	0	0	0	0
Wind	237	241	258	261	260	298	301	300	301	300	308
Solar	355	349	331	339	363	348	333	309	286	280	260
Storage	2,362	2,379	2,362	2,558	2,619	3,606	3,732	3,910	4,279	4,439	4,761
Nuclear	0	0	0	0	0	0	0	0	0	0	0
Demand Response	60	67	66	73	75	82	83	82	85	84	87
West Planned Resources	**3,013**	**3,036**	**3,018**	**3,231**	**3,317**	**4,334**	**4,450**	**4,601**	**4,951**	**5,103**	**5,417**
West Total Resources	**4,572**	**4,591**	**4,570**	**4,781**	**4,863**	**5,878**	**5,991**	**6,140**	**6,488**	**6,636**	**6,948**
Load	4,232	4,334	4,471	4,605	4,720	4,832	4,959	5,143	5,253	5,374	5,365
Distributed Generation	(2)	(3)	(3)	(3)	(3)	(3)	(3)	(4)	(4)	(4)	(4)
Energy Efficiency	(568)	(624)	(668)	(714)	(760)	(819)	(858)	(900)	(786)	(803)	(826)
West Total obligation	**3,662**	**3,707**	**3,800**	**3,888**	**3,957**	**4,010**	**4,097**	**4,239**	**4,463**	**4,567**	**4,535**
West Reserve Margin	24.9%	23.9%	20.3%	23.0%	22.9%	46.6%	46.2%	44.8%	45.4%	45.3%	53.2%
System											
Total Resources	13,995	13,904	13,782	13,880	13,872	14,799	14,732	15,136	14,729	14,930	15,340
Obligation	10,321	10,493	10,732	10,973	11,205	11,398	11,596	11,957	12,334	12,637	12,666
Planning Reserves (16.8%)	1,486	1,511	1,545	1,580	1,614	1,641	1,670	1,722	1,776	1,820	1,824
Obligation + Reserves	11,807	12,003	12,278	12,553	12,819	13,039	13,265	13,678	14,110	14,456	14,490
System Position	2,188	1,901	1,505	1,327	1,053	1,760	1,467	1,458	618	474	850
Reserve Margin	**35.6%**	**32.5%**	**28.4%**	**26.5%**	**23.8%**	**29.8%**	**27.1%**	**26.6%**	**19.4%**	**18.1%**	**21.1%**

Integrated Portfolio Resource Comparisons by Technology and Year

Table 9.16 through Table 9.28 report the incremental capacity of each technology type for each integrated portfolio and integrated variant portfolio. Table 9.29 through Table 9.32 report the capacity of coal generating units that are retired, converted to natural gas fueling, or augmented with carbon capture technology. Table 9.33 summarizes how full jurisdictional studies were identified for each variant and price-policy scenario. Full jurisdictional studies are only modified and endogenously developed to the extent the variant relates to resources that can be selected for that jurisdiction. As a result, the Oregon and Washington full jurisdictional portfolios are not modified in the variants that examine coal resource alternatives. Similarly, Washington requires planning under the social cost of greenhouse gases, so its full jurisdictional portfolio is not modified under other price-policy scenarios. Those variants related to clean resources in which all jurisdictions can participate have full jurisdictional portfolios for each jurisdiction.

Table 9.16 – New Gas[1]

Study	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
MN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MR Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Coal 2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Offshore Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Forward Technology	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Hunter Retire	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	99	-	-	-	99
LN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	496	496
HH Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SC Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

[1] Positive values indicate installed capacity in the first full year of operation.

Table 9.17 - Nuclear[1]

Study	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
MN Base	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	500
MR Base	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	500
MN - No CCS	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	500
MN - No Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Coal 2032	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	500
MN - Offshore Wind	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	500
MN - No Forward Technology	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Geothermal	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	500
MN - Hunter Retire	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	500
LN Base	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	500
HH Base	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	500
SC Base	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	500

[1] Positive values indicate installed capacity in the first full year of operation.

Table 9.18 – Renewable Peaking[1]

Study	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
MN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19	-	4	-	18	41
MR Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19	-	4	-	18	41
MN - No CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19	-	4	-	18	41
MN - No Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Coal 2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19	-	4	-	18	41
MN - Offshore Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Forward Technology	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Hunter Retire	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19	-	4	-	18	41
LN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HH Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19	-	4	-	18	41
SC Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

[1] Positive values indicate installed capacity in the first full year of operation.

Table 9.19 – DSM – Energy Efficiency

Study	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
MN Base	92	89	209	220	239	261	329	291	299	295	299	315	347	314	293	301	303	315	238	205	182	5,436
MR Base	92	89	209	221	231	256	329	313	326	315	318	326	369	335	313	308	304	315	254	224	209	5,656
MN - No CCS	92	89	207	218	229	253	326	287	284	282	294	300	333	312	292	289	304	315	260	232	219	5,417
MN - No Nuclear	92	89	210	220	237	256	331	314	310	299	299	314	324	267	283	251	286	299	282	261	220	5,444
MN - No Coal 2032	92	89	210	221	231	251	319	304	308	298	309	325	347	314	293	299	304	315	270	246	220	5,565
MN - Offshore Wind	92	89	209	219	240	260	331	292	306	294	299	322	345	314	310	301	303	314	222	218	182	5,462
MN - No Forward Technology	92	89	210	220	237	256	331	315	310	301	301	315	324	267	283	251	286	299	282	247	219	5,435
MN - Geothermal	92	89	207	217	227	245	306	298	303	293	313	320	354	335	313	308	305	314	270	259	218	5,586
MN - Hunter Retire	92	89	219	232	243	265	332	306	310	307	312	328	358	326	306	301	304	315	258	224	209	5,636
LN Base	92	89	207	223	236	257	325	288	300	289	311	318	343	309	322	305	302	291	272	244	217	5,540
HH Base	92	89	211	223	237	257	309	295	300	289	309	315	347	326	305	302	305	316	259	252	230	5,568
SC Base	92	89	211	226	241	263	329	293	314	305	318	325	357	325	320	308	305	315	270	260	219	5,685

Table 9.20 – DSM – Demand Response

Study	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
MN Base	18	2	-	63	21	120	99	5	1	3	3	21	112	18	5	24	61	106	29	26	52	789
MR Base	18	2	-	63	19	16	3	5	1	5	3	19	323	18	5	24	114	34	34	25	205	936
MN - No CCS	18	2	-	63	19	34	187	5	1	3	3	21	93	18	5	25	6	176	30	26	50	785
MN - No Nuclear	18	2	-	63	20	136	13	8	26	79	32	4	70	14	151	24	46	31	12	102	48	899
MN - No Coal 2032	18	2	-	63	19	16	-	5	1	3	3	19	328	18	5	25	5	146	33	27	51	787
MN - Offshore Wind	18	2	-	63	20	206	21	8	-	10	4	4	110	29	5	11	8	166	30	31	50	796
MN - No Forward Technology	18	2	-	63	21	131	13	10	26	77	35	6	70	13	151	24	45	31	12	102	57	907
MN - Geothermal	18	2	-	60	20	16	-	8	-	7	5	7	-	13	10	26	450	29	8	7	103	789
MN - Hunter Retire	18	2	-	63	19	211	14	5	1	3	3	23	113	18	129	25	7	147	29	30	87	947
LN Base	18	2	-	63	19	75	149	7	2	4	4	14	110	14	5	24	124	-	8	80	51	773
HH Base	18	2	-	63	22	13	-	5	1	3	3	19	-	18	8	24	5	463	15	157	30	869
SC Base	18	2	2	64	28	191	14	5	1	1	18	11	108	18	10	24	6	150	12	50	46	779

Table 9.21 – Utility Scale Wind[1]

Study	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
MN Base	-	-	-	21	794	1,452	344	1	-	29	347	40	175	37	-	376	50	-	20	-	96	3,782
MR Base	-	-	-	21	694	1,931	200	382	100	129	447	40	175	37	-	376	50	-	20	-	96	4,698
MN - No CCS	-	-	-	21	594	1,252	276	1	-	29	347	40	175	37	-	376	50	-	20	-	96	3,314
MN - No Nuclear	-	-	-	-	500	1,728	300	301	302	322	380	292	2	-	-	-	-	-	-	-	-	4,127
MN - No Coal 2032	-	-	-	21	594	2,914	-	1	-	29	347	40	175	37	-	376	50	-	20	-	96	4,700
MN - Offshore Wind	-	-	100	100	762	630	400	1	1,000	98	100	100	-	-	-	353	95	-	-	-	162	3,901
MN - No Forward Technology	-	-	-	-	694	1,482	302	301	-	22	294	53	176	38	-	367	91	-	1	-	147	3,968
MN - Geothermal	-	-	-	-	594	402	200	1	2	-	169	204	185	89	-	360	62	-	38	-	19	2,325
MN - Hunter Retire	-	-	-	21	894	1,842	340	1	-	29	347	40	175	37	-	376	50	-	20	-	96	4,268
LN Base	-	-	-	-	594	1,265	594	2	-	24	369	1	176	38	-	365	90	-	3	-	150	3,671
HH Base	-	-	-	21	1,214	2,677	-	2	-	29	349	40	175	37	-	376	50	-	20	-	96	5,086
SC Base	-	-	-	20	1,614	1,353	352	1	-	65	293	237	114	26	29	423	47	-	-	11	196	4,781

[1] Positive values indicate installed capacity in the first full year of operation.

Table 9.22 – Small Scale Wind[1]

Study	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
MN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MR Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Coal 2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Offshore Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Forward Technology	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Hunter Retire	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HH Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SC Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

[1] Positive values indicate installed capacity in the first full year of operation.

Table 9.23 – Utility Solar[1]

Study	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
MN Base	-	-	-	222	180	1,690	849	240	403	225	13	-	1	-	554	104	12	-	-	197	75	4,765
MR Base	-	-	-	222	180	1,690	863	934	420	467	213	133	1	-	554	104	12	-	-	197	75	6,065
MN - No CCS	-	-	-	222	180	1,690	614	240	403	225	13	-	1	-	554	104	12	-	-	197	75	4,530
MN - No Nuclear	-	-	-	656	-	1,444	962	299	326	395	456	391	1	-	-	-	-	-	-	22	108	5,060
MN - No Coal 2032	-	-	-	222	180	1,690	494	635	545	792	114	100	1	-	554	104	12	-	-	197	75	5,715
MN - Offshore Wind	-	-	103	237	205	1,382	885	249	104	100	100	100	103	392	444	100	-	-	-	116	26	4,646
MN - No Forward Technology	-	-	119	13	-	1,968	962	220	327	316	49	-	1	-	577	85	34	-	-	239	111	5,021
MN - Geothermal	-	-	29	505	1	1,168	200	163	349	199	103	-	2	27	82	229	211	-	-	333	104	3,705
MN - Hunter Retire	-	-	-	222	180	2,352	1,173	240	403	225	13	-	1	-	554	104	12	-	-	197	75	5,751
LN Base	-	-	-	200	138	1,761	517	239	398	230	7	-	1	-	570	93	61	-	-	44	110	4,369
HH Base	-	-	-	222	181	1,813	1,904	734	603	360	196	-	1	-	554	104	12	-	-	197	75	6,956
SC Base	-	-	22	381	144	2,005	1,259	335	400	206	225	90	1	-	471	115	-	-	-	288	92	6,034

[1] Positive values indicate installed capacity in the first full year of operation.

Table 9.24 – Small Scale Solar[1]

Study	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
MN Base	-	-	-	-	-	320	2	18	26	21	30	132	-	309	-	-	110	-	-	143	36	1,147
MR Base	-	-	-	-	-	320	2	18	26	21	30	132	-	309	-	-	110	-	-	143	36	1,147
MN - No CCS	-	-	-	-	-	320	2	18	26	21	30	132	-	309	-	-	110	-	-	143	36	1,147
MN - No Nuclear	-	-	-	-	-	320	2	18	26	21	26	53	-	307	-	49	153	-	10	126	36	1,147
MN - No Coal 2032	-	-	-	-	-	320	2	18	26	21	30	132	-	309	-	-	110	-	-	143	36	1,147
MN - Offshore Wind	-	-	-	-	-	416	-	-	-	-	-	-	-	24	29	114	142	-	36	250	26	1,037
MN - No Forward Technology	-	-	-	-	-	320	2	18	26	21	30	127	-	307	-	-	117	-	35	108	36	1,147
MN - Geothermal	-	-	-	-	-	304	-	11	29	17	23	17	15	201	331	13	21	-	35	18	26	1,061
MN - Hunter Retire	-	-	-	-	-	320	2	18	26	21	30	132	-	309	-	-	110	-	-	143	36	1,147
LN Base	-	-	-	-	-	320	2	18	26	21	31	153	-	306	-	-	97	-	35	101	36	1,146
HH Base	-	-	-	-	-	320	2	18	26	21	30	132	-	309	-	-	110	-	-	143	36	1,147
SC Base	-	-	-	-	-	320	2	19	26	23	24	20	9	312	-	42	170	-	-	56	26	1,049

[1] Positive values indicate installed capacity in the first full year of operation.

Table 9.25 – Geothermal

Study	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
MN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MR Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Coal 2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Offshore Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Forward Technology	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Geothermal	-	-	403	304	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	707
MN - Hunter Retire	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HH Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SC Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

[1] Positive values indicate installed capacity in the first full year of operation.

Table 9.26 – Battery, < 8 hour [1]

Study	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
MN Base	-	-	-	1,146	242	296	-	119	39	210	20	47	-	175	67	113	67	713	5	459	733	4,451
MR Base	-	-	-	1,156	215	438	-	119	39	210	20	47	27	175	67	113	582	33	5	305	324	3,875
MN - No CCS	-	-	2	1,146	215	299	-	119	39	210	20	47	-	175	188	113	67	115	5	758	-	3,518
MN - No Nuclear	-	-	16	1,399	109	462	-	274	39	209	34	72	313	130	6	937	159	-	605	10	602	5,376
MN - No Coal 2032	-	-	-	1,145	215	565	-	119	39	210	20	47	-	175	67	113	67	152	5	416	18	3,373
MN - Offshore Wind	-	-	7	2,291	527	528	-	149	-	131	46	54	2	251	113	1,454	211	675	768	82	834	8,123
MN - No Forward Technology	-	-	-	1,349	179	316	6	182	41	279	30	83	333	186	112	1,322	272	287	444	251	605	6,277
MN - Geothermal	-	-	-	1,048	184	650	-	241	4	203	37	70	-	179	37	1,437	473	-	104	53	449	5,169
MN - Hunter Retire	-	-	4	1,145	215	836	-	119	39	210	20	47	41	175	67	113	67	129	5	109	185	3,526
LN Base	-	-	-	1,252	220	609	-	99	39	209	23	82	-	239	67	1,126	1,060	-	272	12	1,437	6,746
HH Base	-	-	2	1,146	302	1,383	-	119	39	210	20	47	-	175	67	113	67	-	5	-	-	3,695
SC Base	-	-	-	2,147	329	484	-	175	7	194	2	23	-	286	121	1,095	138	245	192	237	531	6,206

[1] Positive values indicate installed capacity in the first full year of operation.

Table 9.27 – Battery, 8-23 hour[1]

Study	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
MN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MR Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No CCS	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1
MN - No Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Coal 2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Offshore Wind	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1
MN - No Forward Technology	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Hunter Retire	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HH Base	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1
SC Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

[1] Positive values indicate installed capacity in the first full year of operation.

Table 9.28 – Battery, 24+ hour [1]

Study	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
MN Base	-	-	-	-	-	511	91	3	4	3	4	4	11	83	37	939	107	319	402	197	358	3,073
MR Base	-	-	-	-	-	510	91	3	4	3	4	4	175	83	37	939	107	510	401	197	455	3,523
MN - No CCS	-	-	-	-	-	511	91	3	4	3	4	4	11	83	37	939	107	261	402	197	358	3,015
MN - No Nuclear	-	-	-	-	-	191	2	3	3	3	3	3	114	3	3	186	78	233	168	118	4	1,115
MN - No Coal 2032	-	-	-	-	-	510	91	3	4	3	4	4	33	83	37	939	107	390	401	197	358	3,164
MN - Offshore Wind	-	-	-	-	-	1,577	20	23	23	22	25	26	24	27	28	127	34	142	96	30	34	2,258
MN - No Forward Technology	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Geothermal	-	-	-	-	-	85	1	1	1	1	1	1	1	1	2	13	84	85	316	174	88	855
MN - Hunter Retire	-	-	-	-	-	837	91	3	4	3	4	4	123	83	146	939	107	455	401	197	537	3,934
LN Base	-	-	-	-	-	271	95	4	4	3	4	4	17	38	40	132	26	215	137	159	16	1,165
HH Base	-	-	-	-	-	511	91	3	4	3	4	4	11	83	37	939	107	641	402	197	598	3,635
SC Base	-	-	-	-	-	1,410	107	19	19	18	20	21	69	22	34	141	141	442	219	169	94	2,945

[1] Positive values indicate installed capacity in the first full year of operation.

Table 9.29 – Majority Owned Coal Retirements[1]

Study	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
MN Base	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)
MR Base	-	-	-	(220)	-	-	-	(686)	-	-	-	-	-	-	-	-	-	-	-	-	-	(906)
MN - No CCS	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)
MN - No Nuclear	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)
MN - No Coal 2032	-	-	-	(220)	-	-	-	(686)	-	-	-	-	-	-	-	-	-	-	-	-	-	(906)
MN - Offshore Wind	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)
MN - No Forward Technology	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)
MN - Geothermal	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)
MN - Hunter Retire	-	-	-	(220)	-	(1,158)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,378)
LN Base	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)
HH Base	-	-	-	(220)	-	-	(268)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(488)
SC Base	-	-	-	(488)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(269)	-	-	(757)

[1] Negative values indicate retirement of coal capacity.

Table 9.30 – Carbon Capture and Sequestration Selections

Study	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
MN Base	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	(526)	-	-	0
MR Base	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	(526)	-	-	0
MN - No CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Nuclear	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	526
MN - No Coal 2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Offshore Wind	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	(526)	-	-	0
MN - No Forward Technology	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	526
MN - Geothermal	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	(526)	-	-	-	0
MN - Hunter Retire	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	(526)	-	-	0
LN Base	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	(526)	-	-	-	0
HH Base	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	(526)	-	-	0
SC Base	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	526

Table 9.31 – Coal to Gas Conversion Selections

Study	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
MN Base	-	357	-	-	205	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	406
MR Base	-	357	-	-	205	1,979	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	2,385
MN - No CCS	-	357	-	-	205	-	-	-	-	-	-	-	-	-	-	-	-	-	(403)	-	-	159
MN - No Nuclear	-	357	-	-	205	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	562
MN - No Coal 2032	-	357	-	-	205	2,679	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	3,085
MN - Offshore Wind	-	357	-	-	205	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	406
MN - No Forward Technology	-	357	-	-	205	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	562
MN - Geothermal	-	357	-	-	205	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	562
MN - Hunter Retire	-	357	-	-	205	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	562
LN Base	-	357	-	-	205	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	562
HH Base	-	357	-	-	205	599	-	-	(269)	-	-	-	-	-	-	-	-	-	-	-	-	892
SC Base	-	357	-	-	205	330	-	-	-	-	-	-	-	-	-	-	-	-	(99)	-	-	793

Table 9.32 – Gas Retirements[1]

Study	Installed Capacity, MW																					
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
MN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MR Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Coal 2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Offshore Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Forward Technology	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Hunter Retire	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HH Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SC Base	-	-	-	(167)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(167)

[1]Only reports retirements of existing gas plants.

Preferred Portfolio Variants

Driven by emergent federal and state law and stakeholder interest, the 2025 IRP features 7 preferred portfolio variants developed to analyze key resource and transmission decisions. The iterative deterministic process consistently yields portfolios that are reliable once proxy resources are available for selection. Consequently, there is no meaningful comparison of unserved energy between the various portfolios, and cost and risk comparison tables below do not include a measure of ENS. As discussed in Chapter 8, some of the studies below were able to fulfill the requirements of another study and are noted as such. Table 9.33 summarizes the jurisdictional studies which were integrated for each of the variants and price-policy scenarios. Variants evaluating technology that is available in all jurisdictions have jurisdictional portfolios developed for each jurisdiction. Where a jurisdiction does not use the applicable technology or assumptions under consideration in the variant, selections for that jurisdiction are held constant at their base scenario. For example, neither Oregon nor Washington participates in coal-fired resources over the long term, so studies that evaluate alternative decisions for coal-fired resources hold Oregon and Washington jurisdictional results constant. Similarly, Washington requires that the SCGHG price-policy scenario be used for planning, so Washington selections under SCGHG are integrated regardless of the price-policy scenario under consideration.

Table 9.33 – Jurisdictional Studies for Variants and Price-Policy Scenarios

Price-policy / Variant	UIWC	OR	WA	Description
MN - Base	Base	Base		MN price-policy scenario
MR - Base	✓			MR price-policy scenario
LN - Base	✓	✓		LN price-policy scenario
HH - Base	✓	✓		HH price-policy scenario
SC - Base	✓	✓	Base	SCGHG price-policy scenario
MN - No CCS	✓			No coal units are able to select CCS technology
MN - No Coal 2032	✓			All coal must retire or convert by January 1, 2032
MN - Hunter Retire	✓			Require all Hunter units to retire no later than 1/1/2030
MN - No Nuclear	✓	✓	✓ (SC)	No nuclear resources are eligible for selection
MN - Offshore Wind	✓	✓	✓ (SC)	Counterfactual to preferred portfolio selection
MN - No Forward Technology	✓	✓	✓ (SC)	No nuclear, hydrogen or 100-hour storage, or biodiesel peaking
MN - Geothermal	✓	✓	✓ (SC)	Counterfactual to preferred portfolio selection
MN - All Coal End of Life	Same as No CCS			Continue 2025 coal technology
MN - No New Gas	Same as Preferred Portfolio			No new gas resources allowed
MN - Force All Gas Conversions	Same as No Coal 2032			All coal must be converted to natural gas where available

Table 9.34 summarizes the cost and risk results of the variant studies under expected conditions represented by the MN (medium gas price/no CO_2) price-policy scenario. As in previous IRPs, model results can indicate the need to examine costs and risks beyond the model horizon. End effects were applied to all portfolios run under the MN price-policy for a 5-year period after the study horizon, results of which can be seen in this table. The specific trends that led to this examination can be found in the discussion of individual cases below.

Table 9.34 – Integrated Portfolios Under Medium Gas/ Zero CO_2

	ST Value			Risk Adjusted			With End Effects			CO2 Emissions		
Case - MN	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Stochastic PVRR	Change from Lowest Cost Portfolio ($m)	Rank	PVRR ($m)	Change from Lowest Portfolio	Rank	Total CO2 Emissions, 2025-2045 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
Integrated Base MN	27,233	$171	4	27,618	$106	2	34,663	$0	1	317,054	109,082	9
Integrated No CCS MN	28,345	$1,283	6	28,886	$1,374	6	35,768	$1,105	6	386,023	178,051	13
Integrated No Nuclear MN	28,878	$1,816	9	29,301	$1,789	8	36,457	$1,794	7	320,486	112,515	10
Integrated No Coal Post 2032 MN	28,438	$1,376	7	29,235	$1,723	7	36,751	$2,088	8	215,237	7,265	3
Integrated Offshore Wind MN	34,645	$7,583	13	35,127	$7,615	13	42,917	$8,255	13	310,014	102,043	7
Integrated No Future Tech MN	29,110	$2,048	10	29,534	$2,022	10	36,946	$2,284	10	330,034	122,063	11
Integrated Geothermal MN	29,208	$2,146	11	29,946	$2,434	11	37,188	$2,525	11	310,138	102,167	8
Integrated Hunter Retire MN	27,062	$0	1	27,765	$253	3	34,960	$297	3	269,208	61,237	6
Integrated Base MR	27,176	$114	3	27,913	$401	4	35,385	$723	5	207,971	0	1
Integrated No CCS MR	28,581	$1,519	8	29,374	$1,862	9	36,896	$2,233	9	213,302	5,331	2
Integrated Base LN	27,785	$723	5	27,970	$458	5	35,167	$504	4	340,068	132,096	12
Integrated Base HH	27,119	$57	2	27,512	$0	1	34,714	$51	2	238,450	30,479	4
Integrated Base SC	29,787	$2,725	12	30,088	$2,575	12	37,904	$3,242	12	257,126	49,155	5

Table 9.35, below, summarizes the cost and risk results of the variant studies under conditions represented by the LN (low gas price/zero CO_2) price-policy scenario.

Table 9.35 –Integrated Portfolios Under Low Gas/ Zero CO_2

	ST Value			CO2 Emissions		
Case - LN	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Total CO2 Emissions, 2025-2045 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
Integrated Base LN	25,113	$498	4	315,803	54,380	10
Integrated Base MN	25,226	$611	5	334,470	73,047	12
Integrated No CCS MN	25,847	$1,232	8	361,938	100,514	13
Integrated No Nuclear MN	28,638	$4,023	12	315,004	53,580	9
Integrated No Coal Post 2032 MN	25,428	$814	6	261,423	0	4
Integrated Offshore Wind MN	37,505	$12,890	13	299,472	38,049	7
Integrated No Future Tech MN	26,507	$1,892	9	326,791	65,368	11
Integrated Geothermal MN	26,936	$2,322	10	300,704	39,281	8
Integrated Hunter Retire MN	24,959	$344	2	273,675	12,251	6
Integrated Base MR	24,615	$0	1	254,697	(6,726)	2
Integrated No CCS MR	25,580	$965	7	261,242	(181)	3
Integrated Base HH	24,990	$375	3	248,840	(12,584)	1
Integrated Base SC	27,805	$3,190	11	270,860	9,437	5

Table 9.36 summarizes the cost and risk results of the variant studies under conditions represented by the HH (high gas price/high CO_2) price-policy scenario.

Table 9.36 – Integrated Portfolios Under High Gas and Coal/ High CO_2

Case - HH	ST Value			CO2 Emissions		
	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Total CO2 Emissions, 2025-2045 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
Integrated Base HH	31,498	$0	1	174,521	444	2
Integrated Base MN	34,498	$3,000	8	232,976	58,900	13
Integrated No CCS MN	35,762	$4,264	11	219,378	45,302	12
Integrated No Nuclear MN	35,275	$3,777	10	202,255	28,178	10
Integrated No Coal Post 2032 MN	33,052	$1,553	4	179,879	5,803	4
Integrated Offshore Wind MN	45,727	$14,228	13	194,780	20,703	8
Integrated No Future Tech MN	35,902	$4,404	12	207,187	33,110	11
Integrated Geothermal MN	35,247	$3,749	9	189,861	15,785	7
Integrated Hunter Retire MN	31,973	$475	3	179,948	5,871	5
Integrated Base MR	31,796	$297	2	180,431	6,355	6
Integrated No CCS MR	33,110	$1,612	5	178,538	4,461	3
Integrated Base LN	33,995	$2,496	6	201,609	27,532	9
Integrated Base SC	34,207	$2,709	7	174,077	0	1

Table 9.37 summarizes the cost and risk results of the variant studies under conditions represented by the SCGHG (medium gas price/social cost of greenhouse gas) price-policy scenario.

Table 9.37 – Integrated Portfolios Under Medium Gas/ Social Cost of CO_2

	ST Value			CO2 Emissions		
Case - SC	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Total CO2 Emissions, 2025-2045 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
Integrated Base SC	40,268	$2,628	7	103,326	3,072	3
Integrated Base MN	40,882	$3,242	8	117,244	16,990	9
Integrated No CCS MN	41,851	$4,210	11	120,282	20,028	12
Integrated No Nuclear MN	38,899	$1,258	4	115,060	14,806	8
Integrated No Coal Post 2032 MN	39,186	$1,545	5	105,996	5,742	5
Integrated Offshore Wind MN	51,719	$14,079	13	110,124	9,870	7
Integrated No Future Tech MN	41,797	$4,157	10	117,608	17,354	10
Integrated Geothermal MN	40,942	$3,302	9	106,062	5,808	6
Integrated Hunter Retire MN	38,034	$394	2	101,094	840	2
Integrated Base MR	38,708	$1,067	3	117,634	17,380	11
Integrated No CCS MR	39,227	$1,586	6	104,731	4,477	4
Integrated Base LN	42,873	$5,232	12	157,891	57,637	13
Integrated Base HH	37,640	$0	1	100,254	0	1

Integrated Portfolios Under Medium Gas/ Federal Regulation (MR)

Three variant cases examined compliance under the current language in EPA 111(d): the base MR case, the MR No CCS case, and the No Coal Post-2032 case. Details for each MR case is included with the discussions of the integrated portfolio results below.

Variant Study Analysis

No CCS Variant

This variant does not allow Jim Bridger 3 and 4 to convert to CCS during the study horizon. The Jim Bridger units are allowed to either operate as base coal fired with no additional equipment installed, or to convert to gas in 2030. The analysis explores the potential costs and benefits of alternatives to CCS at Jim Bridger 3 and 4 if CCS were found not to be commercially viable at this location. As Jim Bridger 3 and 4 run as coal in this case, the No CCS variant serves as the "All Coal End of Life" variant as well.

Figure 9.17 shows the cumulative (at left) and incremental (at right) portfolio changes when CCS at Jim Bridger 3 and 4 is not allowed on the system starting in 2030. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. When Jim Bridger units 3 and 4 do not convert to CCS, they continue to run as coal. Over the course of the horizon, fewer proxy resources are built. There is reduction of 469 MW of wind, 236 MW of solar and 989 MW of battery, with battery reductions occurring in 2042 and 2045.

Figure 9.17 - Increase/(Decrease) in Proxy Resources with No CCS

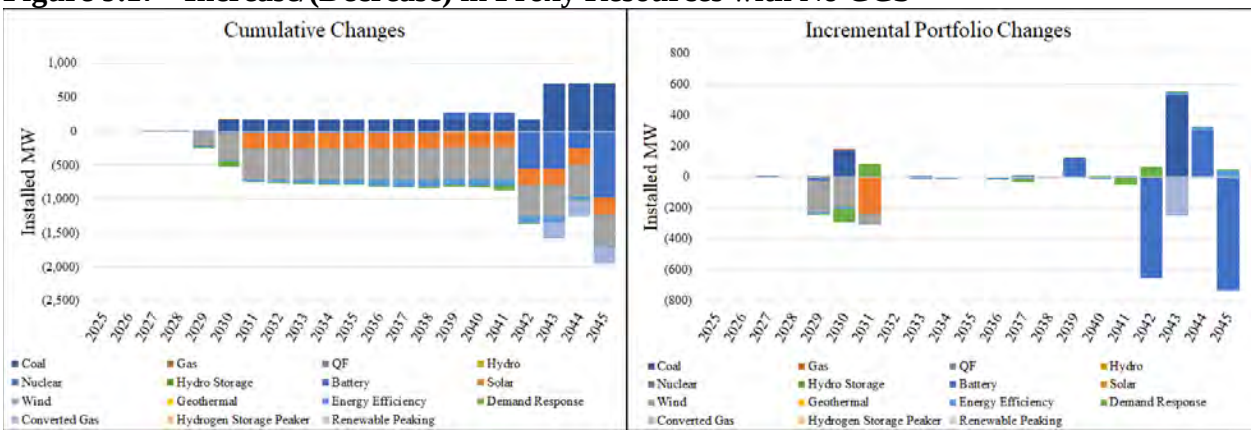
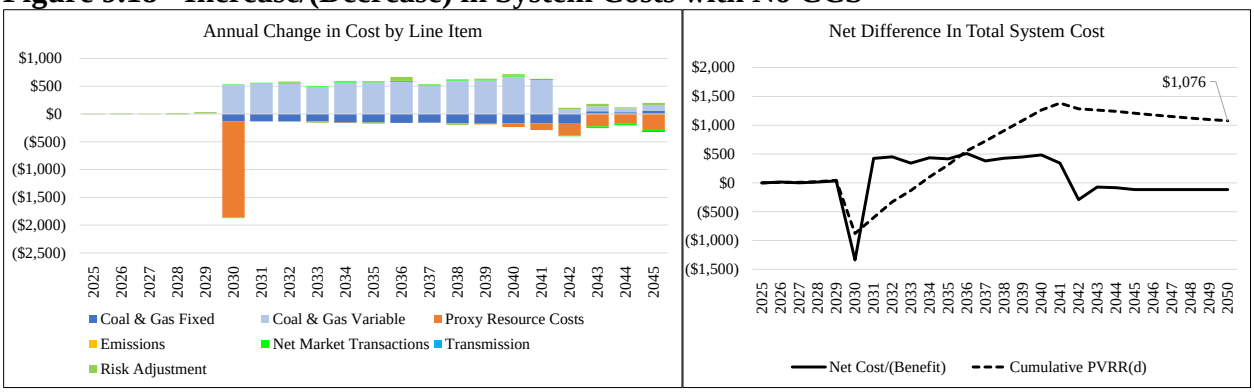


Figure 9.18 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when CCS is removed from the portfolio. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When CCS is removed from the portfolio, the resulting portfolio has a $1.076 billion increase in costs compared to the preferred portfolio.

Despite the significant reduction in capital cost without installing CCS, the loss of the 45Q tax credits more than overtakes the capital savings over the course of the 21-year study period.

Figure 9.18 - Increase/(Decrease) in System Costs with No CCS



No Nuclear Variant

This variant does not allow the Natrium™ demonstration nuclear project to be selected as a resource option in 2032. Additionally, this variant does not allow any proxy nuclear to be selected as a potential replacement for the Natrium™ project. The analysis explores the potential costs and benefits of replacement resource options should the nuclear projects prove unviable.

Figure 9.19 shows the cumulative (at left) and incremental (at right) portfolio changes when nuclear options are not allowed on the system. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The variant case does not select small renewable peaking resources and reduces 100-hour battery selection by 1,955 MW. The No Nuclear portfolio does add an additional 923 MW of 4-hour storage, 347 MW

of wind, 296 MW of solar, and 120 MW of DSM. This study also keeps the CCS at Jim Bridger and Naughton 1 gas conversion through the end of the study horizon.

Figure 9.19 - Increase/(Decrease) in Proxy Resources with No Nuclear

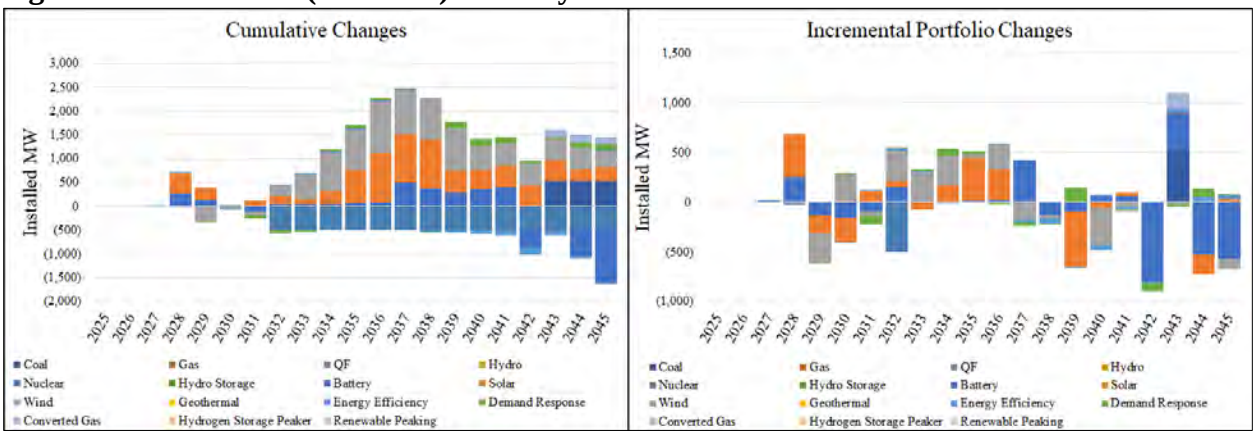
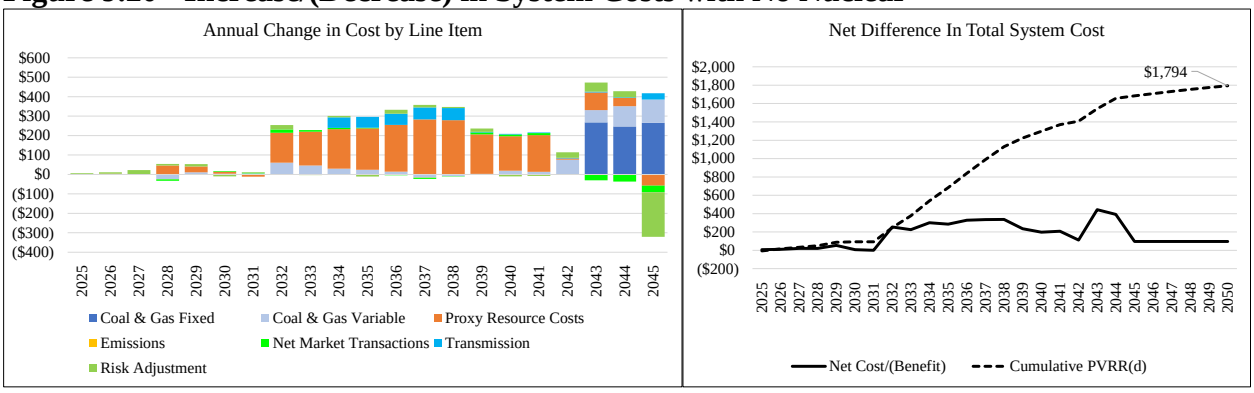


Figure 9.20 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when nuclear projects are removed from the portfolio. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When the Natrium™ demonstration project is removed from the portfolio, the resulting portfolio has a $1.794 billion increase in costs compared to the preferred portfolio. Given that no costs associated with the Natrium™ demonstration project are included in modeling, the increase in costs reflects the loss of all energy and PTC benefits associated with the project.

As seen in Figure 9.20 below, these increases come primarily from significant early proxy resource additions needed to offset the loss of firm nuclear capacity. Although there is an eventual decrease in proxy resource costs in the final years of the study horizon, the need for early investment overcomes these later potential savings.

Figure 9.20 - Increase/(Decrease) in System Costs with No Nuclear



No Coal Post-2032 Variant

This variant does not allow coal to be on the system in any form after 2032. This means current coal facilities must either convert from coal fired to gas fired or retire. In this view, CCS was not allowed as this would still result in the unit using coal fuel. The analysis explores the potential costs and benefits of early retirement or conversion of the entirety of the coal fleet. This variant is

distinct from the medium gas with federal regulation (MR) price policy study in that it does not allow for CCS while the MR does allow for CCS. Because all units eligible for gas conversion either convert to gas or retire early, this study also serves as the "Force Gas Conversion" variant.

Figure 9.21 shows the cumulative (at left) and incremental (at right) portfolio changes when coal is not allowed on the system starting in 2032. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. Due to the significant changes to the operating characteristics of more than 3,300 MW of the existing coal fleet, large portfolio changes occur. The variant case selects additional energy efficiency and demand response, over 2,200 MW of additional wind and solar, and a shift in storage from 4-hour to long duration.

Figure 9.21 - Increase/(Decrease) in Proxy Resources with No Coal Post-2032

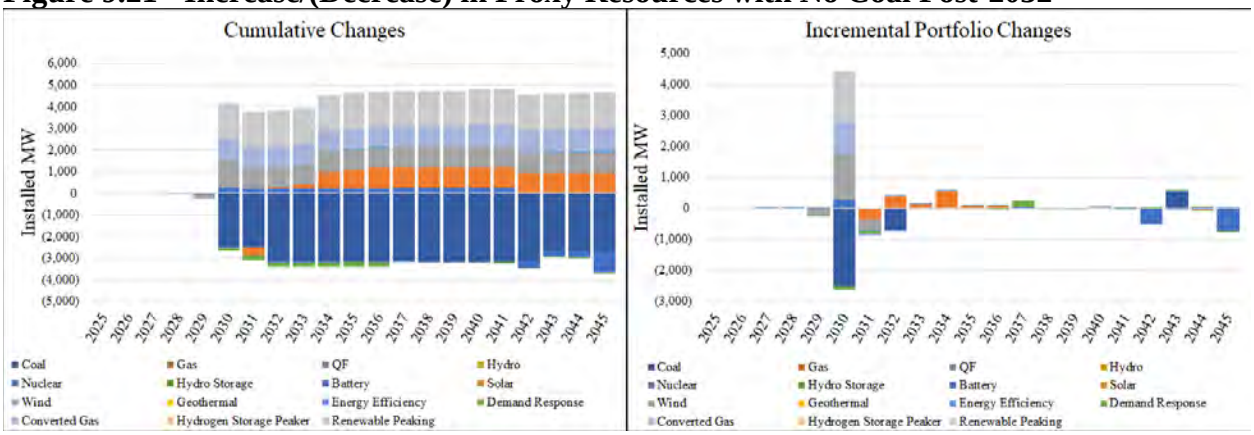
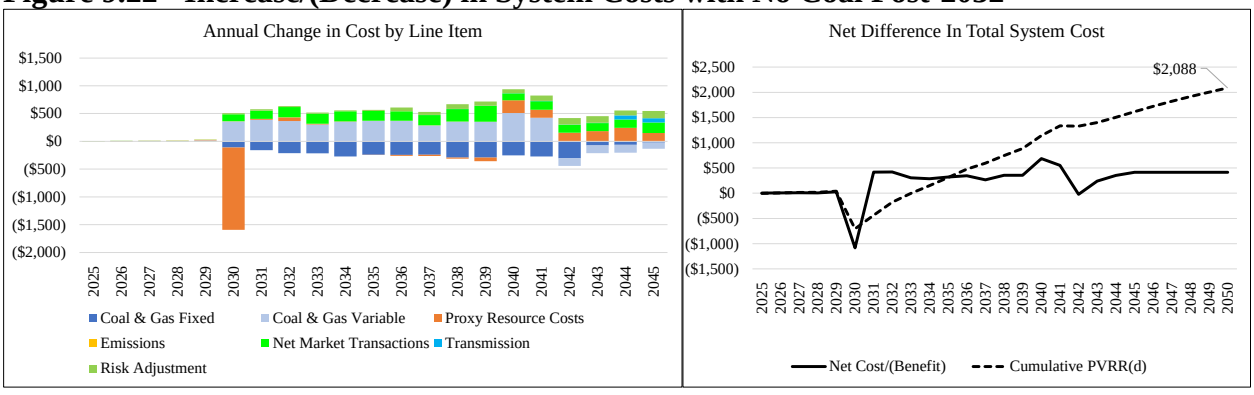


Figure 9.22 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when coal is no longer allowed in the portfolio after 2032. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When all coal must be retired or converted to gas by 2032, the resulting portfolio has a $2.088 billion increase in costs compared to the preferred portfolio.

As seen in Figure 9.22 below, the system cost increase exceeds the impact of 45Q tax credits and CCS capital cost. Additionally, this case has higher levels of market purchases and has higher proxy resource costs in nearly all years of the study horizon.

Figure 9.22 - Increase/(Decrease) in System Costs with No Coal Post-2032



Force Offshore Wind

Since offshore wind was not selected in any of the integrated MN jurisdictional runs, this variant serves as a counterfactual forcing this resource into all jurisdictional runs. The analysis explores the potential costs and benefits of replacing resources selected in various jurisdictional runs with a higher capacity factor offshore wind resource.

Figure 9.23 shows the cumulative (at left) and incremental (at right) portfolio changes when offshore wind is forced into the portfolio in 2033. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The portfolio selects and additional 120 total MW of wind, 3,760 MW of 4-hour storage and 35 MW of additional DSM. These increased selections are partially offset by a reduction of 132 MW of solar and 812 MW of 100-hour storage. Retirements are the same between the studies.

Figure 9.23 - Increase/(Decrease) in Proxy Resources with Offshore Wind

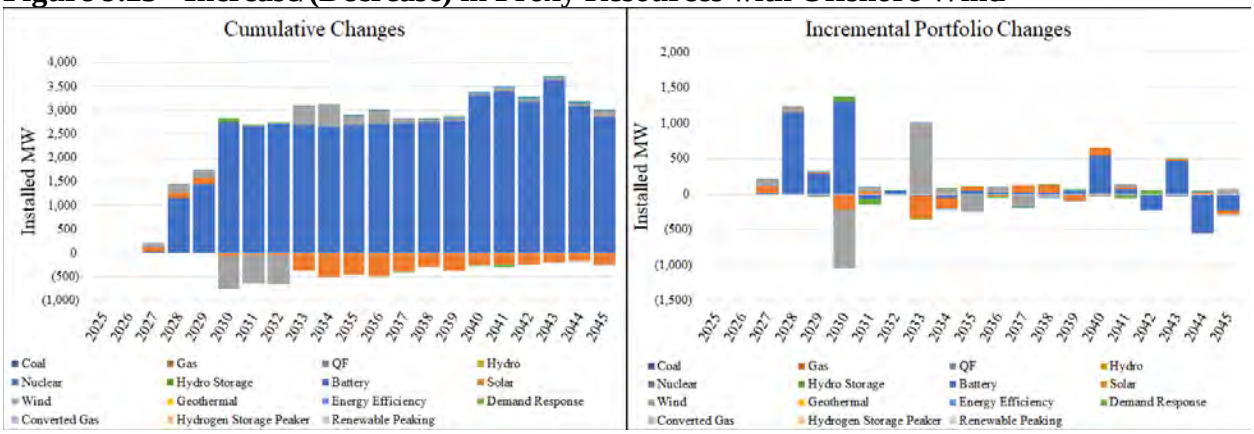
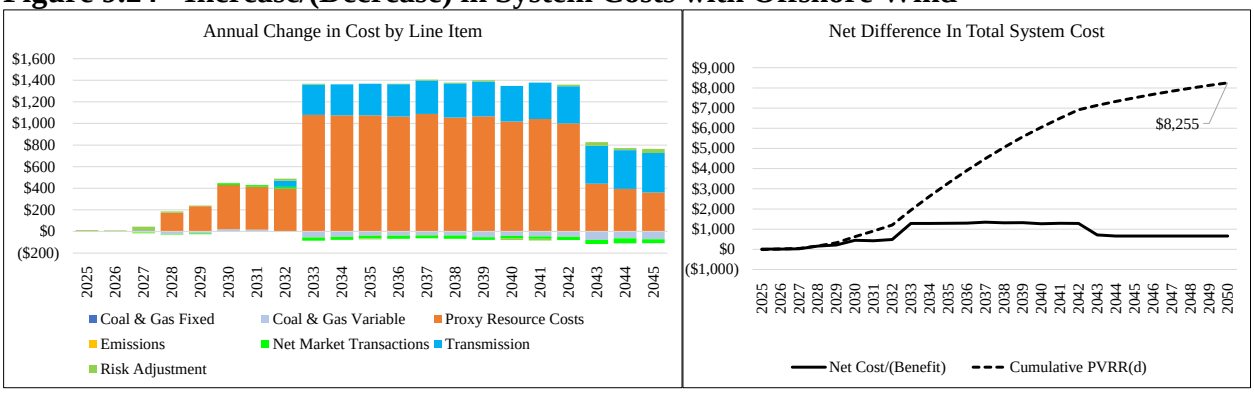


Figure 9.24 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when offshore wind is forced into the various jurisdictional portfolios. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When offshore wind and the required Coos Bay area transmission upgrades are forced into the portfolio, the resulting portfolio has a $8.255 billion increase in costs compared to the preferred portfolio.

As seen in Figure 9.24 below, these increases come primarily from higher overall proxy resource costs, driven by a reduction in production tax credit generating resources. Since the offshore wind resource receives an investment tax credit the loss of production tax credits on approximately 2,900 MW of renewable resources is significant. The balance of the cost in this portfolio is related to the significant overall transmission investments required to enable both the offshore wind resource itself, but also the various transmission upgrades which are required to enable the offshore wind specific transmission line.

Figure 9.24 - Increase/(Decrease) in System Costs with Offshore Wind



No Forward Technology

This variant does not allow the Natrium™ demonstration nuclear project, hydrogen storage, 100-hour battery or small biodiesel peaking units to be selected as resource options. The analysis explores the potential costs and benefits of replacement resource options should these technologies not become commercially viable during the assumed time frame as modeled.

Figure 9.25 shows the cumulative (at left) and incremental (at right) portfolio changes when nuclear options are not allowed on the system. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The variant case selects 120 MW of additional DSM, 187 MW of additional wind and 254 additional MW of solar. The model replaces the 3,073 MW of 100-hour storage with 1,826 MW of 4-hour storage and also does not retire CCS at Jim Bridger or the Naughton 1 gas conversion.

Figure 9.25 - Increase/(Decrease) in Proxy Resources with No Forward Technology

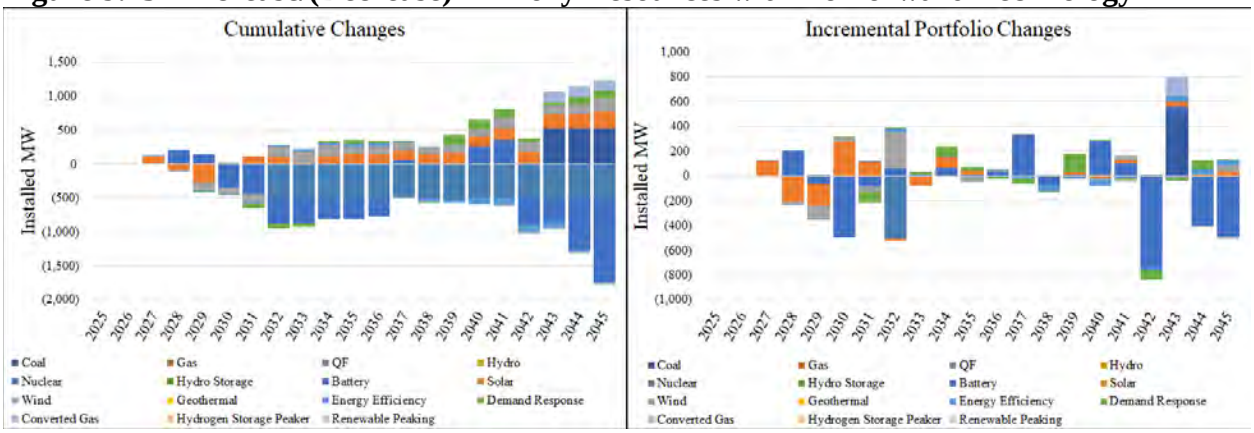
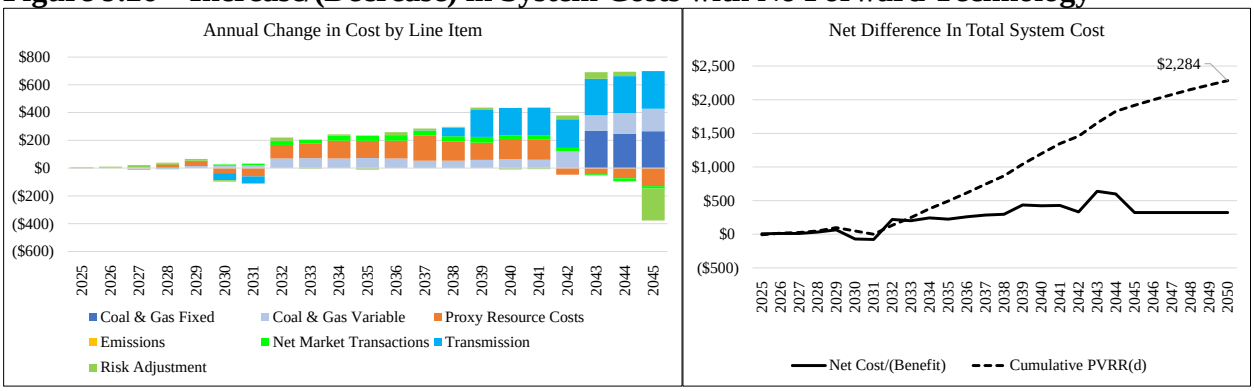


Figure 9.26 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when forward technologies are removed from the portfolio. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When all forward technology is removed from the portfolio, the resulting portfolio has a $2.284 billion increase in costs compared to the preferred portfolio, somewhat higher than the impact of removing Natrium™ alone as shown in Figure 9.20.

As seen in Figure 9.26 below, these increases come primarily from significant early proxy resource additions needed to offset the loss of firm nuclear capacity. Although there is an eventual decrease

in proxy resource costs in the final years of the study horizon, the need for early investment overcomes these later potential savings.

Figure 9.26 – Increase/(Decrease) in System Costs with No Forward Technology



Force Geothermal

Since geothermal was not selected in any of the integrated MN jurisdictional runs, this variant serves as a counterfactual forcing this resource into all jurisdictional runs. The analysis explores the potential costs and benefits of replacing resources selected in various jurisdictional runs with a higher capacity factor geothermal resource.

Figure 9.27 shows the cumulative (at left) and incremental (at right) portfolio changes when geothermal is forced into the portfolio by 2028. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The geothermal study does not retire the Naughton 1 gas conversion. Additionally, the firm capacity more than 700 MW of geothermal reduces the need for other renewable resources. Over 2,500 MW of wind and solar are removed, as well as over 2,200 MW of long duration storage. 719 MW of 4-hour storage is selected in the geothermal study.

Figure 9.27 - Increase/(Decrease) in Proxy Resources with Geothermal

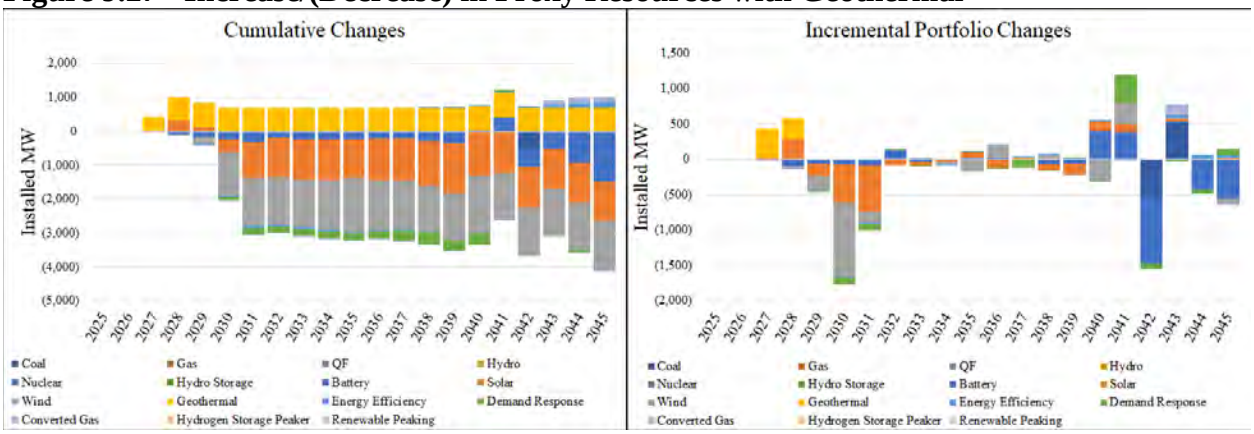
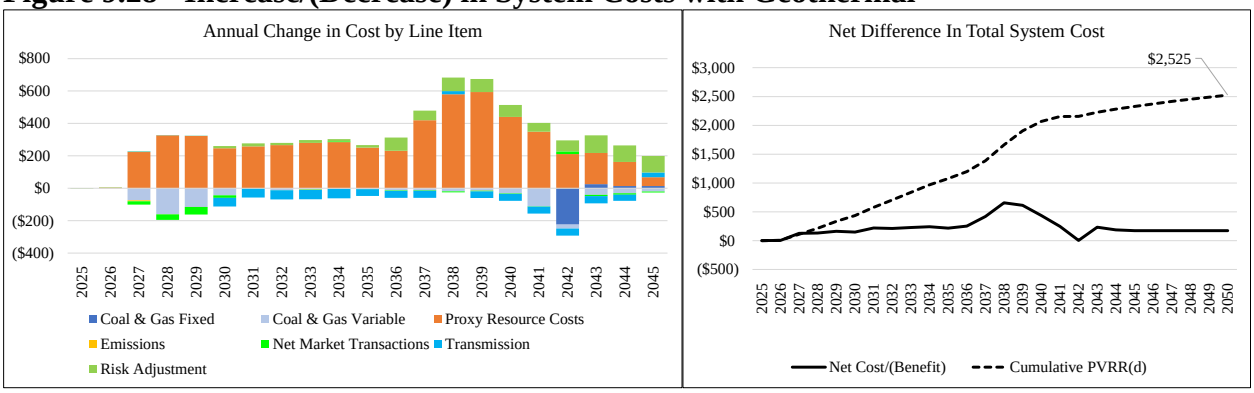


Figure 9.28 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when geothermal is forced into the various jurisdictional portfolios. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When the geothermal is forced into the portfolio, the resulting portfolio has a $2.525 billion increase in costs compared to the preferred portfolio.

As seen in Figure 9.28 below, these increases come primarily from increased costs of the geothermal compared to the lower costs of the renewable resources that were replaced by the geothermal.

Figure 9.28 - Increase/(Decrease) in System Costs with Geothermal



Force Hunter Retirement

Responsive to stakeholder request, PacifiCorp performed a variant analysis exploring what the impact of an early retirement of the Hunter plant would be on the portfolio. In this variant, all units at Hunter were required to retire by 2030. The analysis explores the potential costs and benefits of replacing the Hunter plant with resources selected in the UIWC jurisdictional portfolio when Hunter is not available. Additional consideration of Utah regulations would be necessary before the company would be able to move forward with implementing this variant.

Figure 9.29 shows the cumulative (at left) and incremental (at right) portfolio changes when Hunter is forced to retire in 2030. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The Hunter study does not retire the Naughton 1 gas conversion. The loss of 1,100 MW of firm capacity in 2030 leads to the selection of over 1,100 MW of wind and solar, coupled with 866 MW of additional storage in 2030. By the end of the study horizon, the model selects 99 MW of new gas, an additional 355 MW of energy efficiency and demand response, and over 1,400 MW of new renewables. Total battery selection over the horizon stays the same but has a shift from 4-hour to 100-hour storage.

Figure 9.29 - Increase/(Decrease) in Proxy Resources with Hunter Retirement

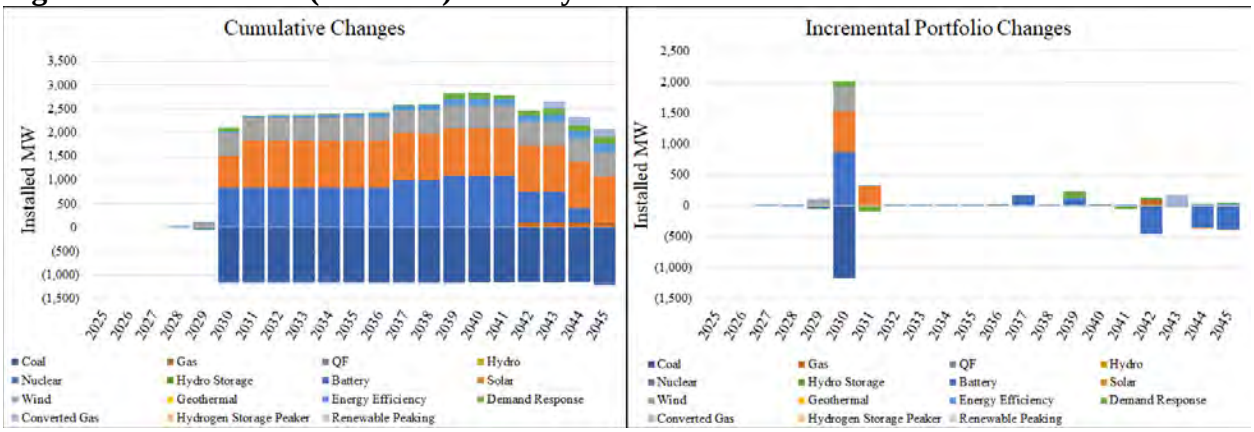
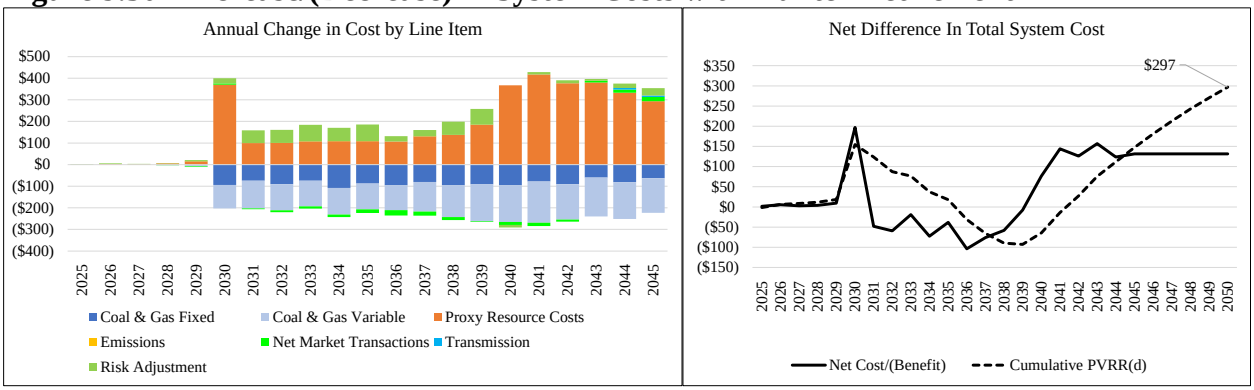


Figure 9.30 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when Hunter is forced to retire in 2030. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When the Hunter is forced to retire in 2030, the resulting portfolio has a $297 million increase in costs compared to the preferred portfolio.

As seen in Figure 9.30 below, these increases come primarily from the additional proxy resource costs associated with replacing the Hunter plant in 2030.

Figure 9.30 - Increase/(Decrease) in System Costs with Hunter Retirement



MR Portfolio

The MR portfolio evaluates resource selections assuming EPA 111(d) rules remain in effect through the study horizon. This portfolio limits new gas capacity factors and requires either installation of CCS, gas conversion, or retirement of existing coal units by 2032. The purpose of this study is to evaluate a path PacifiCorp would pursue for long-term compliance with this rule.

Figure 9.31 shows the cumulative (at left) and incremental (at right) portfolio changes between a medium price, no carbon tax future and a medium price, 111(d) compliance future. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. In an MR future, all plants that are eligible to convert from using coal to using a different fuel type do. Wyodak and Hunter 1 both retire in 2032. This reduction in coal capacity and the significantly lower capacity factor of converted units leads to an additional 1,299 MW of solar, 916 MW of wind and 369 MW of DSM. The portfolio also selects 451 MW of additional 100-hour battery, while removing 575 MW of 4-hour storage.

Figure 9.31 - Increase/(Decrease) in Proxy Resources with MR

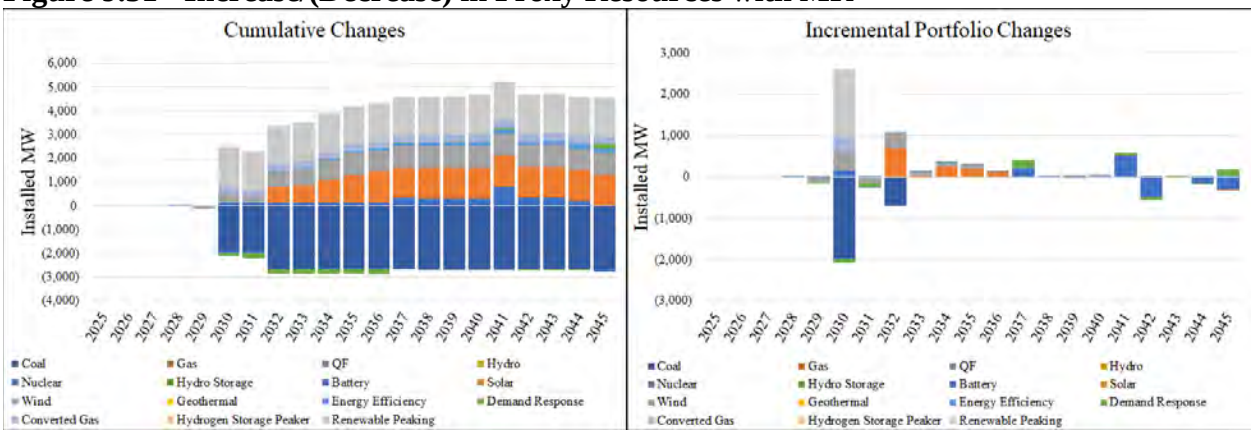
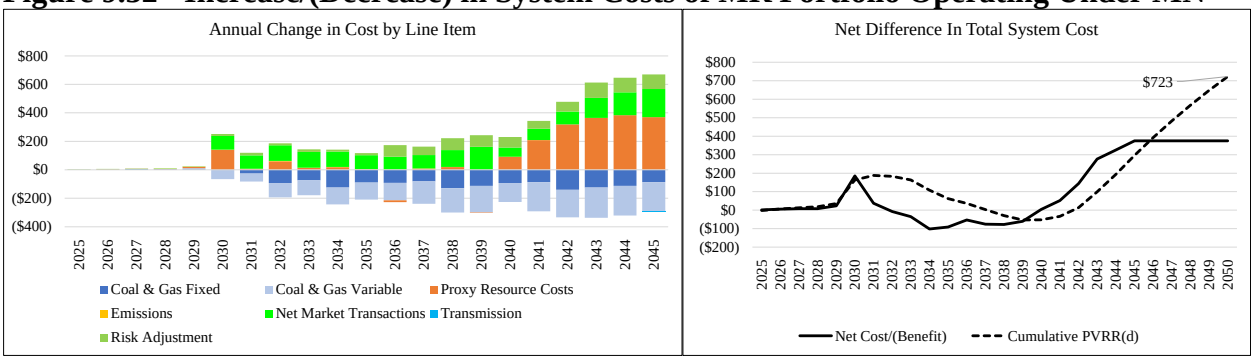


Figure 9.32 summarizes changes in system costs, based on ST model results operating MN price policy portfolio under the MN price policy assumptions. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When the MR portfolio is operating under the MN price policy, the resulting portfolio has a $723 million increase in costs compared to the preferred portfolio.

Figure 9.32 - Increase/(Decrease) in System Costs of MR Portfolio Operating Under MN



MR No CCS

The MR No CCS portfolio evaluates what changes would occur to the MR portfolio if CCS at Jim Bridger were to prove to not be a viable option for EPA 111(d) compliance. This portfolio limits new gas capacity factors and requires either gas conversion, or retirement of existing coal units by 2032, precluding CCS selections. The purpose of this study is to evaluate the path PacifiCorp would take to be compliant with this rule in the absence of CCS at Bridger.

Figure 9.33 shows the cumulative (at left) and incremental (at right) portfolio changes between a medium price, no carbon tax future and a medium price, 111(d) compliance future. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. Jim Bridger 3 and 4 gas convert in lieu of installing CCS and does not retire Naughton 1 gas conversion. Hunter 1 retires in 2031 instead of 2032. Keeping the Jim Bridger and Naughton units leads to lower proxy resource selections across all generating types. The portfolio reduces wind by 55 MW, DSM by 378 MW and solar by 561 MW. Battery selections remain cumulatively the same with a shift from 24-hour battery to 4-hour battery.

Figure 9.33 - Increase/(Decrease) in Proxy Resources with MR No CCS vs. MR

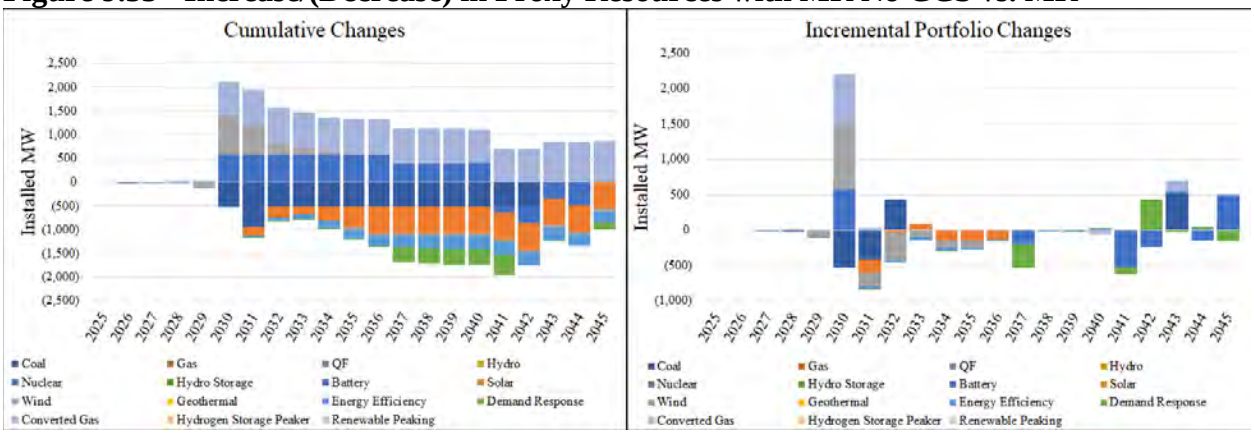
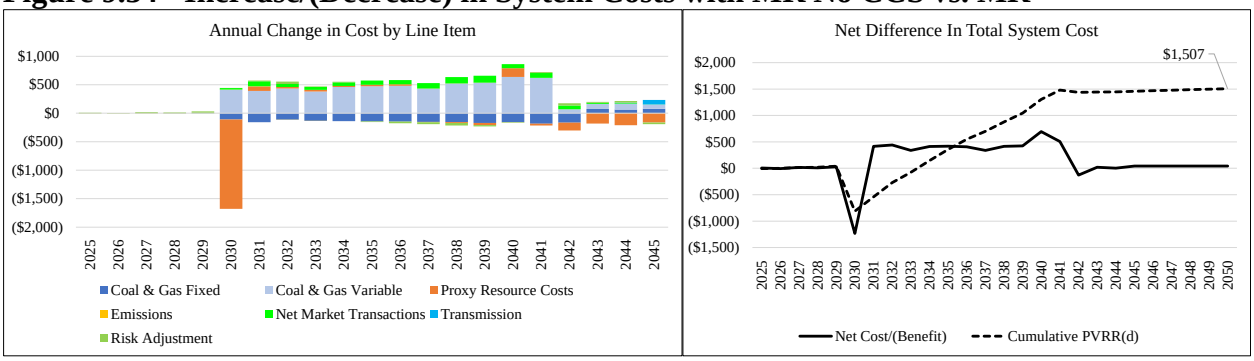


Figure 9.34 summarizes changes in system costs, based on ST model results using MR price-policy assumptions, when CCS is removed from the portfolio. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When CCS is removed from the portfolio, the resulting portfolio has a $1.507 billion increase in costs compared to the MR portfolio with CCS.

Despite the significant reduction in capital cost without installing CCS, the loss of the 45Q tax credits more than overtakes the capital savings over the course of the 21-year study period.

Figure 9.34 - Increase/(Decrease) in System Costs with MR No CCS vs. MR



HH Portfolio

The HH portfolio evaluates what selections would be made under high future costs, including gas, market, and coal. This portfolio integrated Oregon selections under HH, UIWC selections under HH and Washington selections under SC. The purpose of this study is to evaluate the selections PacifiCorp would make if a high-cost future was most likely.

Figure 9.35 shows the cumulative (at left) and incremental (at right) portfolio changes between a medium price, no carbon tax future and a high price future. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The HH Portfolio selects Dave Johnston 4 and Hunter 2 to convert from coal to a different fuel in 2030. The HH also retires Hunter 2 in 2033. The model increases brownfield renewable selections by 2007 MW and selects 562 additional MW of 100-hour storage. There is a reduction in 4-hour

storage of 757 MW, however all selections of additional 4-hour storage occur in 2030 in the HH run. An additional 208 MW of DSM is also selected.

Figure 9.35 - Increase/(Decrease) in Proxy Resources with HH

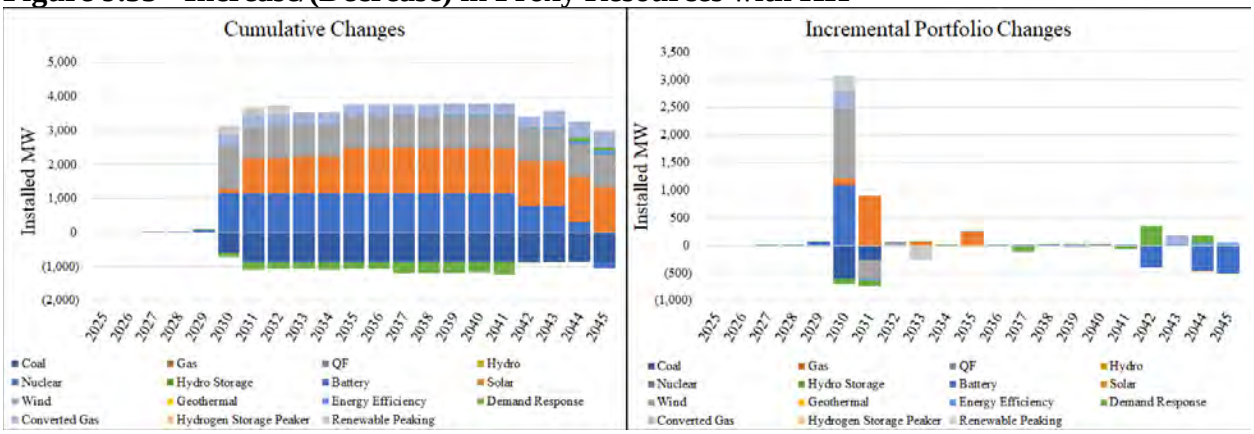
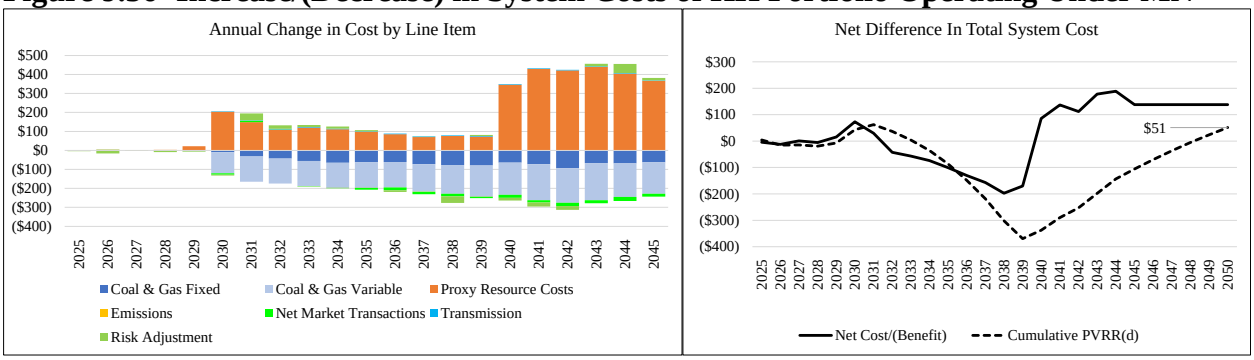


Figure 9.36 summarizes changes in system costs, based on ST model results operating HH price policy portfolio under the MN price policy assumptions. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When the HH portfolio is operating under the MN price policy, the resulting portfolio has a $51 million increase in costs compared to the preferred portfolio.

Figure 9.36- Increase/(Decrease) in System Costs of HH Portfolio Operating Under MN



LN Portfolio

The LN portfolio evaluates what selections would be made under low future costs, including gas and market with no CO_2 tax adder. This portfolio integrated Oregon selections under LN, UIWC selections under LN and Washington selections under SC. The purpose of this study is to evaluate the selections PacifiCorp would make if a low-cost future was most likely.

Figure 9.37 shows the cumulative (at left) and incremental (at right) portfolio changes between a medium price, no carbon tax future and a low-price future. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The LN portfolio delays the retirement of the Jim Bridger CCS conversions one year and does not retire Naughton 1. The LN does select 496 MW of new gas peaking units in 2045 in place of the 41 MW of renewable peaking in the preferred portfolio. There is an increase of 91 MW of DSM, and a reduction of 508 MW of new renewable generation. The model selects and additional 389 MW of storage, swapping 100-hour for 4-hour battery.

Figure 9.37 - Increase/(Decrease) in Proxy Resources with LN

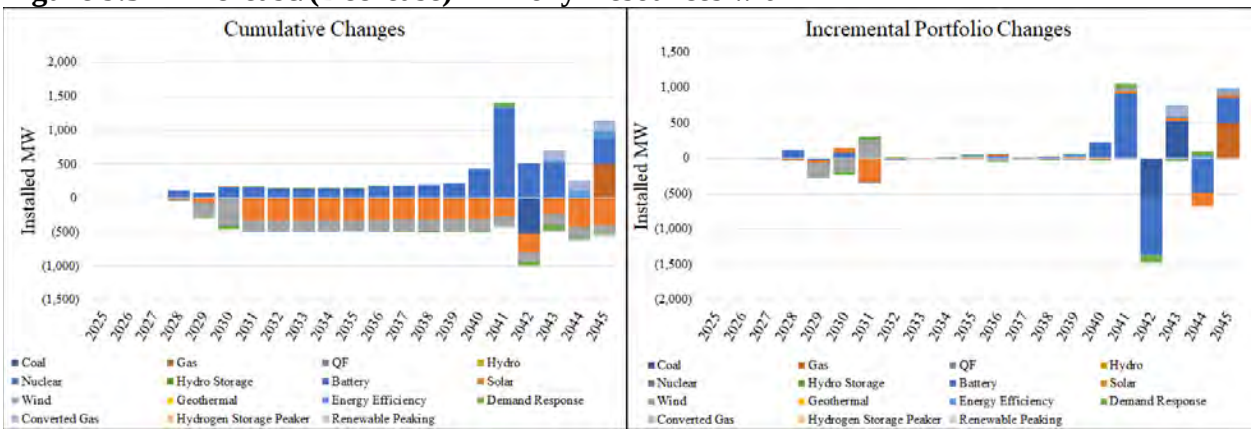
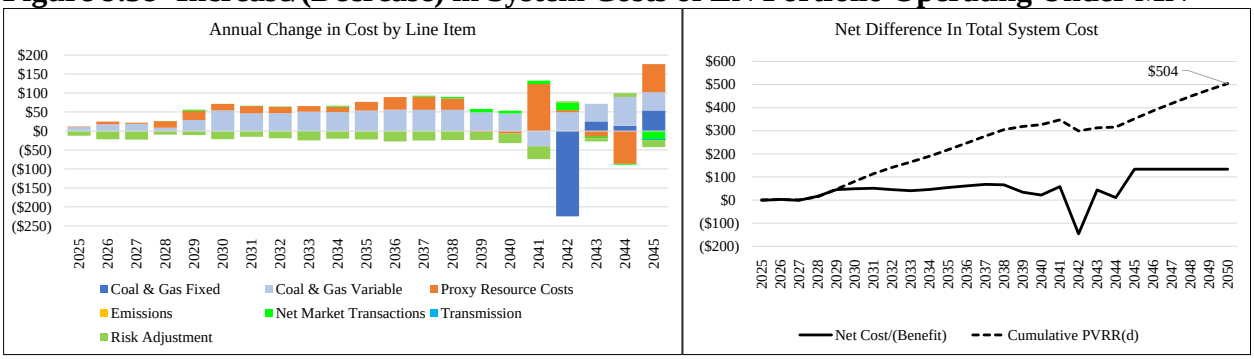


Figure 9.38 summarizes changes in system costs, based on ST model results operating LN price policy portfolio under the MN price policy assumptions. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When the LN portfolio is operating under the MN price policy, the resulting portfolio has a $504 million increase in costs compared to the preferred portfolio.

Figure 9.38- Increase/(Decrease) in System Costs of LN Portfolio Operating Under MN



SCGHG Portfolio

The SCGHG portfolio evaluates what selections would be made under a Social Cost of Greenhouse Gas future. This portfolio integrated all jurisdiction's selections under SCGHG. The purpose of this study is to evaluate the selections PacifiCorp would make if an SCGHG future was most likely.

Figure 9.39 shows the cumulative (at left) and incremental (at right) portfolio changes between a medium price, no carbon tax future and an SCGHG future. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The SCGHG portfolio does not retire the Jim Bridger CCS conversions or Naughton 1 but does retire Wyodak in 2028 and the Dave Johnston 1 gas conversion in 2043. Additionally, the SCGHG case chooses gas conversion at Dave Johnston 4 and allows it to continue through the 21-year horizon and does not retire Naughton 1. The SCGHG case selects an additional 999 MW of utility scale wind, 1,269 MW of utility scale solar, 1,756 MW of 4-hour battery and 240 MW of DSM. The portfolio reduces small scale solar selections by 101 MW and 100-hour storage by 126 MW.

Figure 9.39 - Increase/(Decrease) in Proxy Resources with SCGHG

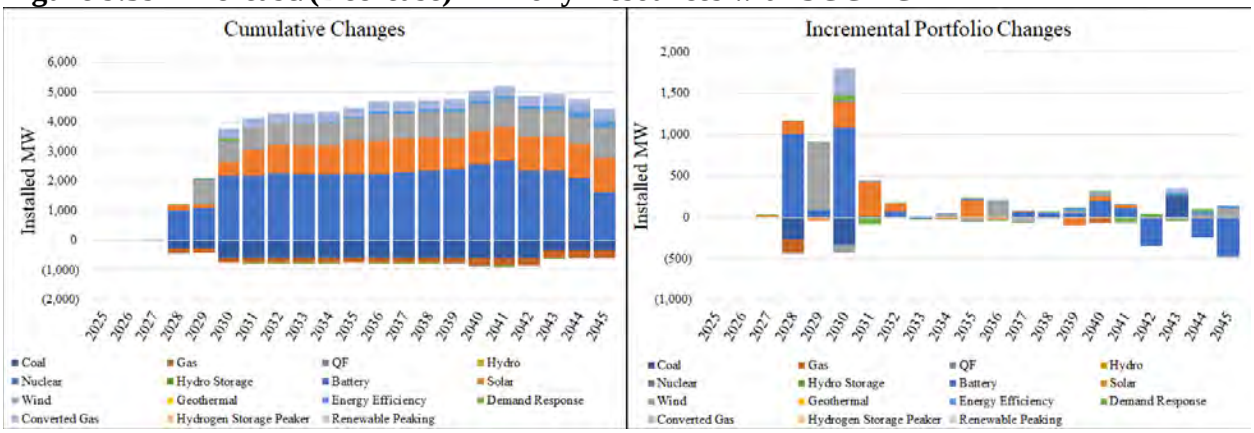
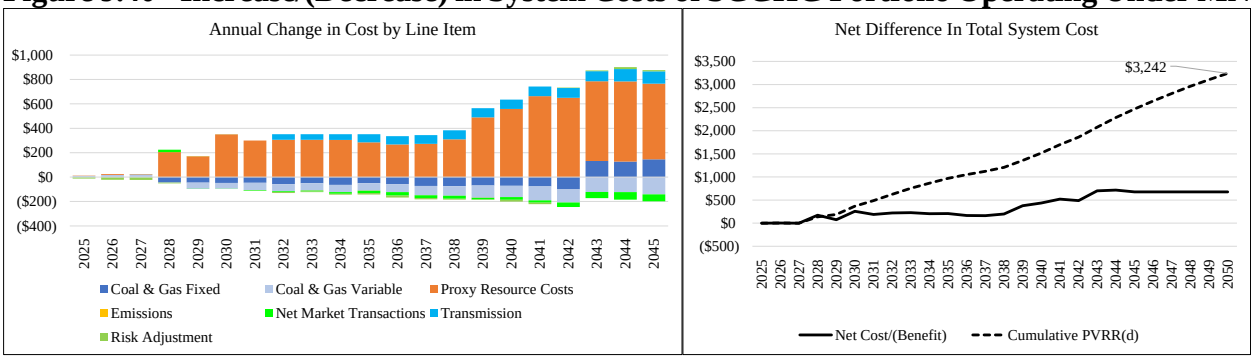


Figure 9.40 summarizes changes in system costs, based on ST model results operating SCGHG price policy portfolio under the MN price policy assumptions. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When the SCGHG portfolio is operating under the MN price policy, the resulting portfolio has a $3.242 billion increase in costs compared to the preferred portfolio.

Figure 9.40 - Increase/(Decrease) in System Costs of SCGHG Portfolio Operating Under MN



Additional Sensitivity Analysis

In addition to the resource portfolios developed and studied as part of the portfolio-development process that supports selection of the preferred portfolio, sensitivity cases were developed to better understand how certain modeling assumptions influence the resource mix and timing of future resource additions. It is assumed that state level compliance would still be required to be met in these sensitivities; Oregon would still need to reduce emissions, and Washington would need to meet CETA targets. These sensitivity cases are also useful as "bookend" analysis to aid in understanding how PacifiCorp's resource plan would be affected by changes to uncertain planning assumptions and to address how alternative resources and planning paradigms affect system costs and risks.

Table S.1 lists additional sensitivity studies to be performed for the 2025 IRP. To isolate the impact of a given planning assumption, all sensitivity cases are evaluated in comparison to the preferred portfolio.

Table S.1– Summary of Additional Sensitivity Cases

Sensitivity	Definition
High Load Growth	Base load forecast replaced by a high load version
Low Load Growth	Base load forecast replaced by a low load version
1-20 Peak Load	Base load forecast replaced by a high load version using historical 20-year highest load
High Distributed Generation	Assumes lower load due to high Distributed Generation adoption
Low Distributed Generation	Assumes higher load due to low Distributed Generation adoption
Large-metered Load Growth	Assumes significant large-metered customer load growth
Low Cost Renewables	Assumes high adoption of IRA/IIJA benefits leads to large cost declines
Low PTC/ITC eligibility	Assumes changes to IRA/IIJA leading to shorter PTC/ITC eligibility window
All CCS	Allows CCS to be selected at additional coal units
Business as Usual	Portfolio if no state requirements existed
Business Plan[8]	First 3 years are aligned with the current business plan

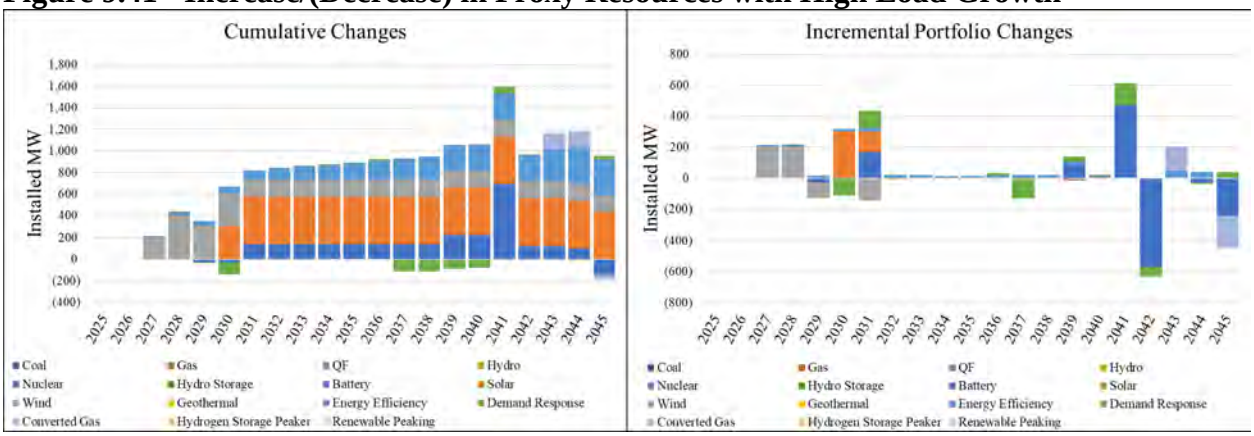
High Load Growth

The High Load Growth sensitivity evaluates what selections would be made if load growth were higher than projected. The purpose of this study is to identify potential additional resource needs if load grows faster than anticipated.

Figure 9.41 shows the cumulative (at left) and incremental (at right) portfolio changes between normal load growth and high load growth. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The high load growth portfolio does not retire Naughton 1 but does retire Naughton 2 in 2045. The higher load growth leads to an additional 319 MW of DSM, 160 MW of wind, and 435 MW of solar. There is a total reduction of 137 MW of storage, with 329 fewer MW of 4-hour storage offset by 100 MW of 8-hour and 92 MW of 100-hour storage.

[8] In the 2025 IRP, the business plan sensitivity is aligned with the integrated preferred portfolio due to the base assumptions being aligned. For this reason, no additional sensitivity is needed.

Figure 9.41 - Increase/(Decrease) in Proxy Resources with High Load Growth

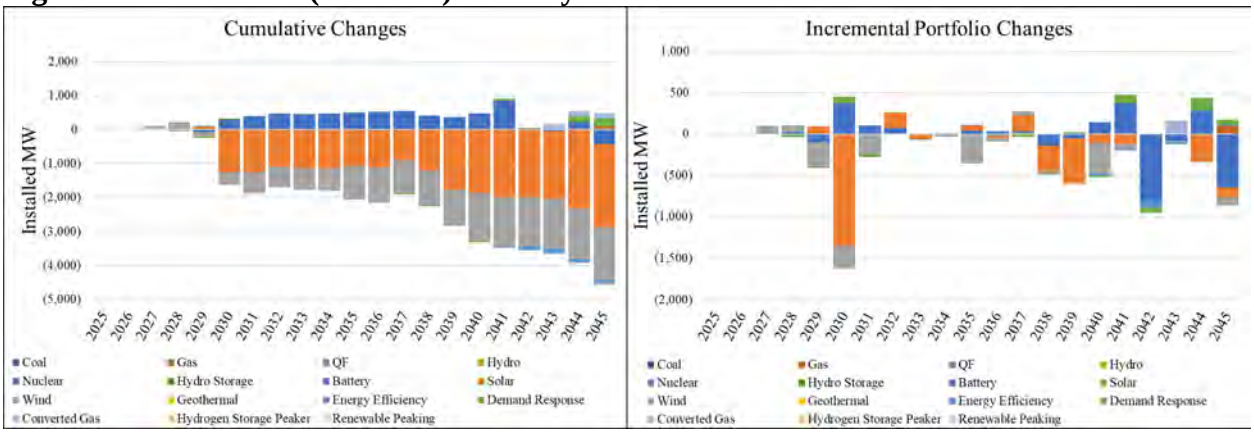


Low Load Growth

The Low Load Growth sensitivity evaluates what selections would be made if load growth were higher than projected. The purpose of this study is to identify which resources might be economic if load grows more slowly than anticipated.

Figure 9.42 shows the cumulative (at left) and incremental (at right) portfolio changes between normal load growth and high load growth. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The low load growth portfolio does not retire Naughton 1. Due to the lower need, the portfolio selects 1,566 MW less wind, 2,440 MW less solar and 425 MW less storage, with a reduction in 100-hour storage offset by additional 4-hour storage. The portfolio does select an additional 125 MW of DSM.

Figure 9.42 - Increase/(Decrease) in Proxy Resources with Low Load Growth



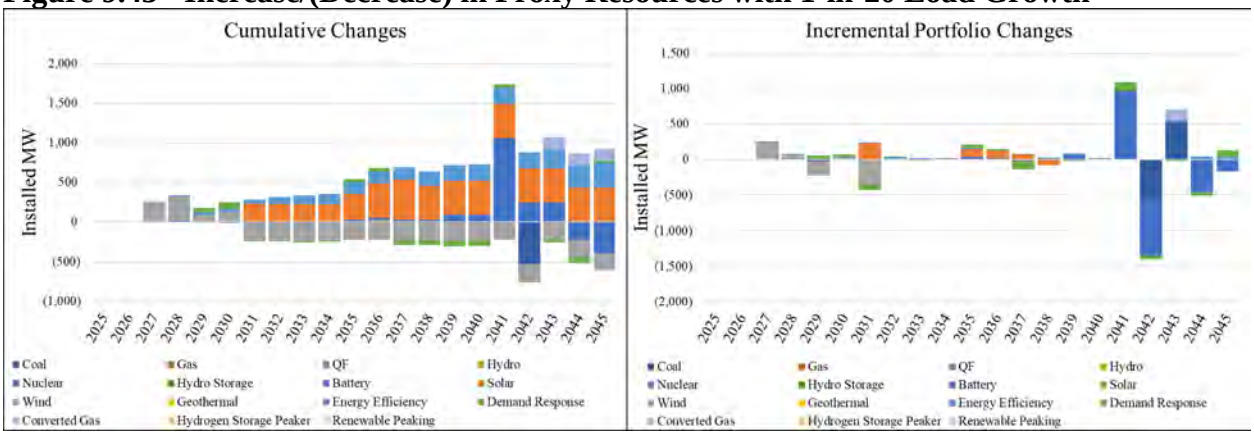
1-in-20 Peak Load Growth

The 1-in-20 Peak Load Growth sensitivity evaluates what selections would be made if load growth were higher than projected. The purpose of this study is to identify potential additional resource needs if peak load is higher than anticipated.

Figure 9.43 shows the cumulative (at left) and incremental (at right) portfolio changes between normal load growth and higher 1-20 peak loads. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The 1-20 peak

load portfolio retires the Jim Bridger CCS conversions 1 year later and does not retire Naughton 1. The higher peak loads lead to an additional 317 MW of DSM and 431 MW of additional solar. There is a reduction of 222 MW of wind and 385 MW of storage.

Figure 9.43 - Increase/(Decrease) in Proxy Resources with 1-in-20 Load Growth

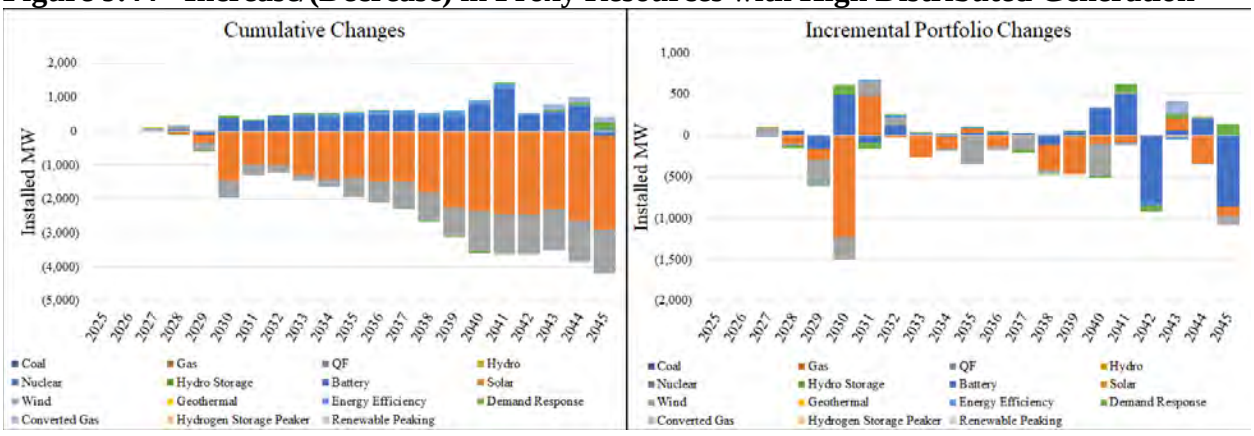


High Distributed Generation Growth

The High Distributed Generation Growth sensitivity evaluates what selections would be made if distributed generation growth were higher than projected (and load was lower as a result). The purpose of this study is to identify which resources would be economic if load is lower than anticipated.

Figure 9.44 shows the cumulative (at left) and incremental (at right) portfolio changes between normal load growth and high load growth. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The high distributed generation growth portfolio selects an additional 269 MW of DSM. The portfolio reduces renewable resources by 4,078 MW and storage resources by 135 MW over the course of the 21-year horizon.

Figure 9.44 - Increase/(Decrease) in Proxy Resources with High Distributed Generation

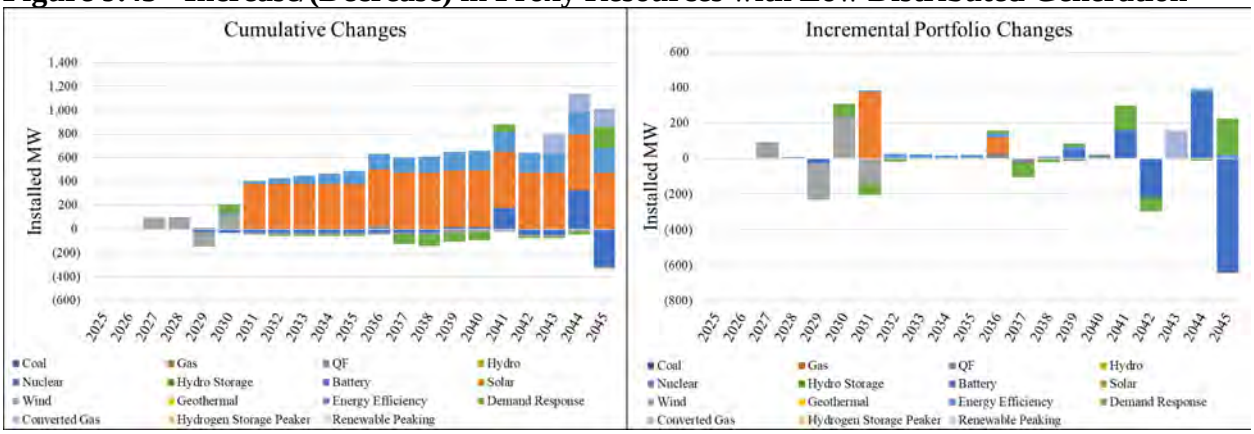


Low Distributed Generation Growth

The low distributed generation growth sensitivity evaluates what selections would be made if distributed generation growth were lower than projected. The purpose of this study is to identify potential additional resource needs if distributed generation growth is lower than anticipated.

Figure 9.45 shows the cumulative (at left) and incremental (at right) portfolio changes between normal load growth and high load growth. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The low distributed generation portfolio does not retire Naughton 1. The higher load need leads to 349 additional MW of DSM and 471 MW of solar. There is a reduction of 15 MW of wind and 351 MW of 4-hour storage partially offset by an additional 40 MW of 100-hour storage.

Figure 9.45 - Increase/(Decrease) in Proxy Resources with Low Distributed Generation



Large-Metered Load Growth

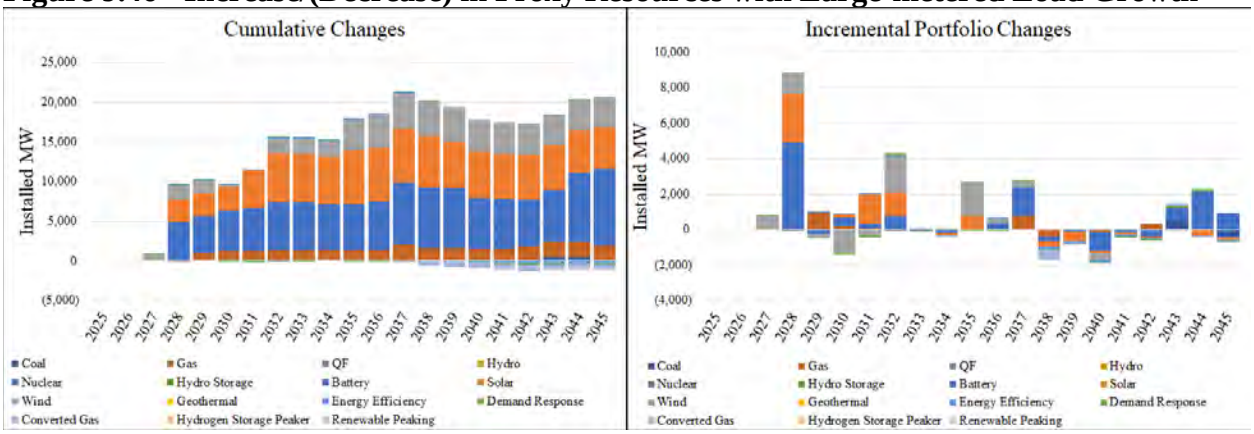
The large-metered load growth sensitivity evaluates what selections of both resources and transmission would be required to serve all large-metered load that could potentially come online in PacifiCorp service territory. The purpose of this study is to identify which resources might be needed if the system had to serve all of these large-metered loads.

Figure 9.46 shows the cumulative (at left) and incremental (at right) portfolio changes between normal load growth and high load growth. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. This sensitivity selects 2,354 MW of gas peaking units, an additional 3,872 MW of utility scale wind, an additional 5,993 MW of utility scale solar and 9,650 MW of additional storage. In 2038, the large-metered load growth portfolio retires 804 MW of existing thermal units that were not retired in the preferred portfolio. In addition to significant resource additions, serving large-metered load requires significant transmission investments. Table 9.38 shows the transmission required in the large-metered load growth study.

Table 9.38 – Large-metered Load Transmission Selections

Line	Year Selected
INC B2H2 Hemingway>Longhorn - 2033	2033
INC BorahPop > Hemingway 2037 Segment E	2037
INC BorahPop > Wasatch Front 2035 D3.2	2044
INC BorahPop > Wasatch Front 2035 D3.3	2035
INC Bridger > BorahPop 2032	2032
INC Bridger > BorahPop 2035 D3.2	2044
INC Bridger > Wyoming East 2032 D2.2	2032
INC Goshen > NUT 2035 1b	2035
INC NUT > Goshen 2029	2029
INC NUT > Wasatch Front 2029	2029
INC NUT > Wasatch Front 2030 2C7 3C6	2030
INC Portland North Coast > Willamette Valley 2037	2037
INC Portland North Coast > Yakima 2029	2029
INC Utah South > Wasatch Front 2028B	2028
INC Utah South > Wasatch Front 2029	2029
INC Utah South > Wasatch Front 2035	2035
INC Willamette Valley > Central OR 2032	2032
INC Willamette Valley > Southern OR 2036	2036
INC Wyoming East > BorahPop 2035 D3.3	2035
INC Wyoming East > Bridger 2032	2032
INC Wyoming East > Clover 2035 GWS2	2044

Figure 9.46 - Increase/(Decrease) in Proxy Resources with Large-metered Load Growth



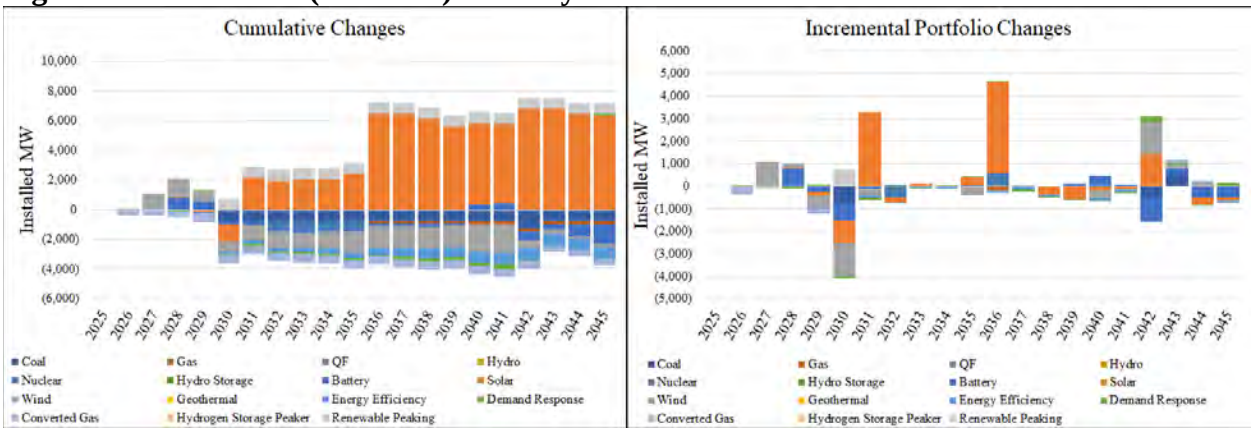
Low-Cost Renewables

The low-cost renewables sensitivity evaluates what selections would be made if renewable resources were lower cost than the current modeling expectations. The purpose of this study is to identify potential additional resources if the company were able to take advantage of all tax credits and assumes advantageous financing to complete projects.

Figure 9.47 shows the cumulative (at left) and incremental (at right) portfolio changes between the preferred portfolio and a portfolio acquiring resources on the advantageous basis described above. A positive value indicates an increase in resources and a negative value indicates a decrease when

a resource is reduced or eliminated. The low-cost renewables portfolio selects 199 MW less wind, but 7,187 MW of additional utility scale solar. The model also selects 950 more MW of short and medium duration storage, but 2,549 MW less 100-hour battery. Of note, coal plants which are able to endogenously retire throughout the horizon convert to alternate fuels but do not retire under this sensitivity.

Figure 9.47 - Increase/(Decrease) in Proxy Resources with Low-Cost Renewables

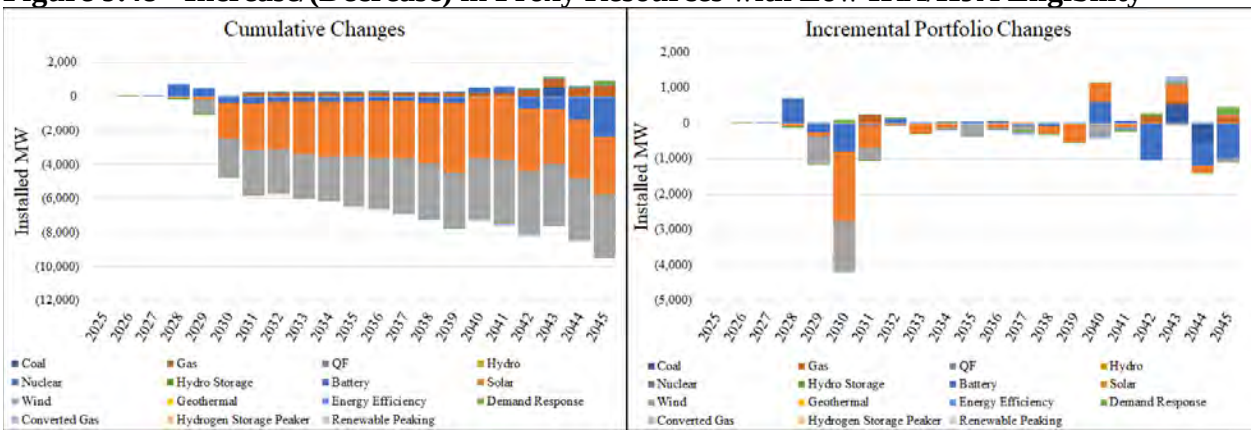


Low IRA/IIJA Eligibility

The low IRA/IIJA sensitivity evaluates what selections would be made if no resources were ever eligible for IRA or IIJA credits. The purpose of this study is to identify the impact if tax credits were not available to any new resources.

Figure 9.48 shows the cumulative (at left) and incremental (at right) portfolio changes between the low IRA/IIJA portfolio and the preferred portfolio. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The low IRA/IIJA portfolio includes an additional 627 MW of gas peaking units, and 311 more MW of DSM. The low IRA/IIJA portfolio also includes a reduction of 3,782 MW of wind and 3,366 MW of solar, as well as 2,382 MW of storage. This sensitivity delays the Bridger CCS retirement by one year.

Figure 9.48 - Increase/(Decrease) in Proxy Resources with Low IRA/IIJA Eligibility

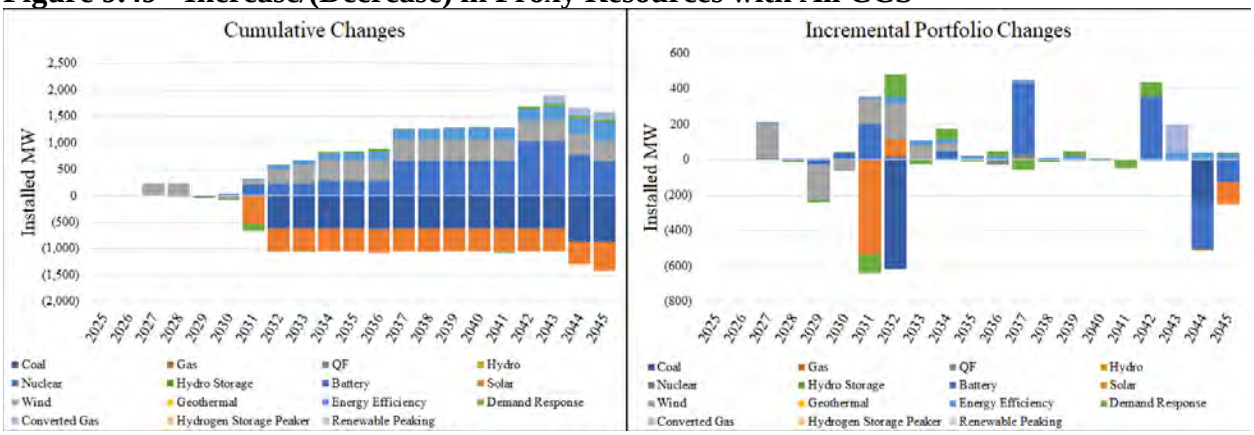


All CCS

The All CCS sensitivity evaluates what selections would change if it were feasible to convert all units to CCS that would be eligible for conversion. The purpose of this study is to identify the impact of installing up to 8 CCS units.

Figure 9.49 shows the cumulative (at left) and incremental (at right) portfolio changes between the base assumption and allowing all CCS. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. In this sensitivity, all eligible units except Wyodak convert to CCS. The lower maximum output means that the sensitivity selects additional resources, including 391 MW of DSM, 397 MW of additional wind and 637 more MW of storage. The only significant reduction is 431 MW of solar.

Figure 9.49 - Increase/(Decrease) in Proxy Resources with All CCS

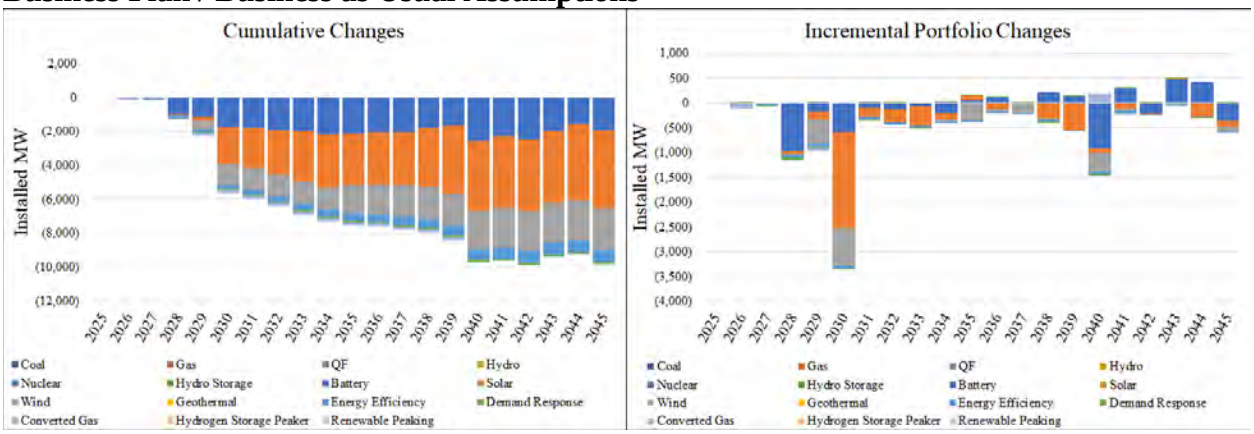


Business as Usual/Business Plan

The business as usual and business plan sensitivities were able to be covered by the same study. The business-as-usual study requires that coal retires no earlier than in the 2017 IRP unless otherwise mandated to do so by law. The business plan study requires that the first three years of the horizon align with the business plan, and then the model is able to endogenously choose any outcomes. These studies explicitly require operation and resource selection in the absence of any state or federal requirements, and the portfolio must be selected only on the basis of economics.

Figure 9.50 shows the cumulative (at left) and incremental (at right) portfolio changes between be preferred portfolio and a business-as-usual case. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. This view selects significantly fewer resources. In total, there are 9,879 fewer MW chosen, and coal continues to remain on the system as in the preferred portfolio. This portfolio selects 2,488 MW less wind, 3,496 MW less utility scale solar, 1,147 MW less small scale solar and a total of 1,903 MW less storage (replacing 100-hour battery with 4-hour battery).

Figure 9.50 - Increase/(Decrease) in Proxy Resources with Business Plan / Business as Usual Assumptions



Washington Scenarios

As described in Chapter 8, in addition to the information provided throughout the 2025 IRP, Washington's CETA legislation mandates three key studies for analysis, in addition to the least-cost, least-risk portfolio developed to meet CETA clean energy standards:

- Alternative Lowest Reasonable Cost
- Maximum Customer Benefit
- Climate Change[9]

This analysis plus additional detail related to Washington requirements is found in Appendix O (Washington Clean Energy Action Plan)

[9] Note: The Washington requirement for a climate change sensitivity, which includes climate change impacts, is met by the incorporation of climate change considerations into all 2025 IRP studies.

CHAPTER 10 –ACTION PLAN

CHAPTER HIGHLIGHTS

- The 2025 Integrated Resource Plan (IRP) action plan identifies steps that PacifiCorp will take over the next two-to-four years to deliver resources in the preferred portfolio. The action plan has been shaped by changes in the planning environment, ongoing review and validation, and stakeholder feedback.
- PacifiCorp's 2025 IRP action plan includes action items for existing resources, new resources, transmission, demand-side management (DSM) resources, short-term firm market purchases, and the purchase and sale of renewable energy credits (RECs).[1]
- The 2025 IRP acquisition path analysis provides insight on how changes in the planning environment might influence future resource procurement activities. Key uncertainties addressed in the acquisition path analysis include load, private generation, changes in available resources, and carbon dioxide (CO_2) emission polices.
- PacifiCorp further discusses how it can mitigate procurement delay risk, summarizes planned procurement activities tied to the action plan, assesses trade-offs between owning or purchasing third-party power, discusses its hedging practices, and identifies the types of risks borne by customers and the types of risks borne by shareholders.

Introduction

PacifiCorp's 2025 IRP action plan identifies the steps the company will take over the next two-to-four years to deliver a least-cost, least-risk portfolio for customers, based on the resources and requirements identified in its preferred portfolio, with a focus on the front five years of the planning horizon.

The 2025 IRP action plan is based on the latest and most accurate information available at the time portfolios are being developed and analyzed on cost and risk metrics. PacifiCorp recognizes that the preferred portfolio, upon which the action plan is based, is developed in an uncertain and evolving planning environment and that resource acquisition strategies need to be regularly evaluated as planning assumptions change.

Resource information used in the 2025 IRP, such as capital and operating costs, are based upon recent projections of cost-and-performance data. However, it is important to recognize that resources identified in the plan include proxy resources, which act as a guide for resource procurement and not as a commitment. Resources evaluated as part of procurement initiatives may vary from the proxy resources identified in the plan with respect to resource type, timing, size, cost, and location.

[1] Changes in procurement planning and Federal legislative drivers for change were discussed in the 2025 IRP public input meeting series. See Appendix M, stakeholder feedback form #11 (Utah Environmental Caucus). See also Appendix M, stakeholder feedback form #13 (Joan Entwistle).

PacifiCorp recognizes the need to support and justify resource acquisitions consistent with then-current laws, regulatory rules and requirements, and commission orders.

In addition to presenting the 2025 IRP action plan, reporting on progress in delivering the prior action plan, and presenting the 2025 IRP acquisition path analysis, this chapter also includes discussion of the following resource procurement topics:

- Procurement delays;
- IRP action plan linkage to the business plan;
- Resource procurement strategy;
- Assessment of owning assets vs. purchasing power;
- Managing carbon risk for existing plants;
- Purpose of hedging; and
- Treatment of customer and investor risks.

The 2025 IRP Action Plan

The 2025 IRP action plan identifies specific actions PacifiCorp will take over roughly the next two-to-four years to deliver its preferred portfolio. Action items are based on the size, type and timing of resources in the preferred portfolio, findings from analysis completed over the course of portfolio modeling, and feedback received by stakeholders in the 2025 IRP public input process. Table 10.1 details specific 2025 IRP action items by resource category.

Table 10.1 – 2025 IRP Action Plan

Action Item	1. Existing Resource Actions
1a	**Colstrip Units 3 and 4:** • PacifiCorp will continue to work with co-owners to develop the most cost-effective path toward an exit from the Colstrip project in Montana by 2030.
1b	**Craig Unit 1:** • PacifiCorp will continue to work closely with co-owners to seek the most cost-effective path forward toward the 2025 IRP preferred portfolio target exit date of December 31, 2025.
1c	**Naughton Units 1 and 2:** • PacifiCorp will continue the process of converting Naughton Units 1 and 2 to natural gas as initiated in Q2 2023, including obtaining all required regulatory notices and filings. Natural gas operations are anticipated to commence spring of 2026. • PacifiCorp will initiate the closure of the Naughton South Ash Pond no later than the end of December 2025 when coal operations cease, and will complete closure by October 17, 2028, as required under its pond closure extension submission.
1d	**Carbon Capture and Storage / Low Carbon Portfolio Standard:** • PacifiCorp will continue to evaluate the economic and technical feasibility of carbon capture technology on Jim Bridger Units 3 and 4 to comply with Wyoming's low carbon portfolio standard. The Company is pursuing a front-end engineering design study as part of compliance with Wyoming's low carbon portfolio standard requirements as a site-specific analysis is needed to better understand the feasibility of the project.[2]
1e	**Regional Haze Compliance:** • Following the resolution of first planning period regional haze compliance disputes, and the EPA's determination of the states' second planning period regional haze state implementation plans, PacifiCorp will evaluate and model any emission control retrofits, emission limitations, or utilization reductions that are required for coal units. • PacifiCorp will continue to engage with the EPA, state agencies, and stakeholders to achieve second planning period regional haze compliance outcomes that improve Class I visibility, provide environmental benefits, and are cost effective.

[2] See Appendix M, stakeholder feedback form #59 (Renewables Northwest).

1f	**Natrium™ Demonstration Project:** • By the end of 2025, PacifiCorp expects to finalize a commercial off-take agreement for the Natrium™ project. PacifiCorp will continue to monitor key TerraPower development milestones and will make regulatory filings, as applicable, including, but not limited to, a request for the Public Utility Commission of Oregon to explicitly acknowledge an alternative acquisition method consistent with OAR 860-089-0100(3)(c), and a request for a waiver of a solicitation for a significant energy resource decision consistent with Utah statute 54-17-501.
1g	**Ozone Transport Rule Compliance:** • EPA finalized its approval of Wyoming's cross-state ozone state plan on December 19, 2023. This approval means PacifiCorp facilities in Wyoming are not subject to the federal ozone plan requirements. • The Tenth Circuit granted a motion to stay EPA's disapproval of Utah's state ozone plan. Utah is not subject to federal ozone requirements while the stay is in place. The Utah ozone case was transferred to the D.C. Circuit in February of 2024, for adjudication of the merits, leaving the stay in place. PacifiCorp will continue to monitor developments in the Utah ozone case and adjust its plans accordingly in response to developments.
1h	**Natural Gas Emissions Compliance Strategies** • The 2025 IRP indicates that changes in accounting and/or dispatch of existing natural gas resources may be a beneficial element of Oregon's HB 2021 compliance strategy and to align with evolving state policies. A range of implementation strategies exist, with intertwined implications on resource allocation, market participation, and compliance requirements. PacifiCorp will meet with impacted parties, program administrators, and regulators to enable a refined analysis of the available options to prepare for implementation no later than the start of 2030.
1i	**Federal Greenhouse Gas Emission Compliance:** • EPA finalized its regulation for existing coal-fueled steam units under Clean Air Act Section 111(d) in April 2024, though the rule has been challenged in the D.C. Circuit. PacifiCorp will continue to update and evaluate alternatives for affected resources while the legal process continues.
1j	**Dave Johnston Units 1 and 2:** • PacifiCorp will initiate the process of converting Dave Johnston Units 1 and 2 to natural gas, including obtaining all required regulatory notices and filings. Natural gas operations are anticipated to commence spring of 2029.

Action Item	2. New Resource Actions
2a	**Customer Preference Request for Proposals:** • PacifiCorp is continuously receiving and evaluating requests for voluntary customer programs in Utah and Oregon. PacifiCorp may use the marginal resources from future request for proposals to fulfill customer need. In some cases, customer preference may necessitate issuance of a request for proposals to procure resources within the action plan window. • Consistent with Utah Community Renewable Energy Act, PacifiCorp will continue to work with eligible communities to develop program to achieve goal of being net 100 percent renewable by 2030; PacifiCorp filed an application for approval of a resource solicitation process for the program with the Utah Public Service Commission in November 2024. PacifiCorp plans to file an application for the remainder of the program during Q1 2025.
2b	**2025 All-Source Request for Proposals:** • PacifiCorp will initiate with individual jurisdictions the process to issue as appropriate by individual jurisdiction need, one or more independent Request for Proposals (RFP) to procure resources aligned with the 2025 IRP preferred portfolio that can achieve commercial operations by the end of December 2029.[3] • Individual independent jurisdictional RFP filings will include timelines associated with the respective jurisdictions' process. • Considering the differentiated resource needs by jurisdiction identified in the 2025 IRP, scope and targeted resource needs may vary by jurisdiction.

[3] Procurement strategy was a frequent topic during the 2025 IRP public input meeting process and stakeholder feedback. See Appendix M, stakeholder feedback form #17 (Public Utility Commission of Oregon). A portion of cost-effective demand response resources identified in the 2025 preferred portfolio in 2025 represent planned volumes are expected to be acquired through a previously issued demand response RFP soliciting resources identified in the 2013 IRP. PacifiCorp will pursue all cost-effective demand response resources identified as incremental to existing resources or as an expansion of existing resources offered through approved programs.

Action Item	3. Transmission Action Items
3a	**<u>Local Reinforcement Projects</u>** Initiate Local Reinforcement Projects as identified with the addition of new resources per the preferred portfolio, and follow-on requests for proposal successful bids.
3b	**<u>Gateway West Support</u>** Continue permitting support for Gateway West segments D.3 and E. Initiate preliminary permitting and development activities for future transmission investments not currently included in the preferred portfolio. These future transmission projects can include development of additional Energy Gateway segments and exploration of new routes that have connections to other regions (i.e., connecting southern Oregon to the east with connections to the desert southwest). These activities will enable PacifiCorp to prepare for potential growth in new large loads seeking new service over the next decade.

<table>
<tr><th>Action Item</th><th>4. Demand-Side Management (DSM) Actions</th></tr>
<tr><td>a</td><td>

Energy Efficiency & Demand Response Targets:

- PacifiCorp will acquire cost-effective energy efficiency resources targeting annual system energy and capacity selections from the preferred portfolio. PacifiCorp's state-specific processes for planning for DSM acquisitions is provided in Appendix D in Volume II of the 2025 IRP.
- PacifiCorp will pursue cost-effective energy efficiency resources.

<table>
<tr><th>Year</th><th>First-Year Energy Efficiency (GWh)</th><th>Annual Capacity (MW)</th></tr>
<tr><td>2025</td><td>595</td><td>92</td></tr>
<tr><td>2026</td><td>573</td><td>89</td></tr>
<tr><td>2027</td><td>597</td><td>209</td></tr>
<tr><td>2028</td><td>648</td><td>220</td></tr>
</table>

- PacifiCorp will pursue cost-effective demand response resources targeting annual system capacity selections from the preferred portfolio.[4] Capacity impacts for demand response include both summer and winter impacts within a year and are incremental to those already included as existing.[5]

<table>
<tr><th>Year</th><th>Annual Incremental Capacity (MW)</th></tr>
<tr><td>2025</td><td>18</td></tr>
<tr><td>2026</td><td>2</td></tr>
<tr><td>2027</td><td>0</td></tr>
<tr><td>2028</td><td>63</td></tr>
</table>

</td></tr>
</table>

[4] A portion of cost-effective demand response resources identified in the 2025 preferred portfolio in 2025 represent planned volumes are expected to be acquired through a previously issued demand response RFP soliciting resources identified in the 2013 IRP. PacifiCorp will pursue all cost-effective demand response resources identified as incremental to existing resources or as an expansion of existing resources offered through approved programs.

[5] See Appendix D, Table D.3 for the split out between summer and winter capacity.

Action Item	5. Market Purchases
5a	**Market Purchases:** • PacifiCorp will acquire short-term firm market purchases for on-peak delivery from 2025-2027 consistent with the Risk Management Policy and Energy Supply Management Front Office Procedures and Practices. These short-term firm market purchases will be acquired through multiple means: o Balance of month and day-ahead brokered transactions in which the broker provides a competitive price. o Balance of month, day-ahead, and hour-ahead transactions executed through an exchange, such as the Intercontinental Exchange, in which the exchange provides a competitive price. o Prompt-month, balance-of-month, day-ahead, and hour-ahead non-brokered bi-lateral transactions.

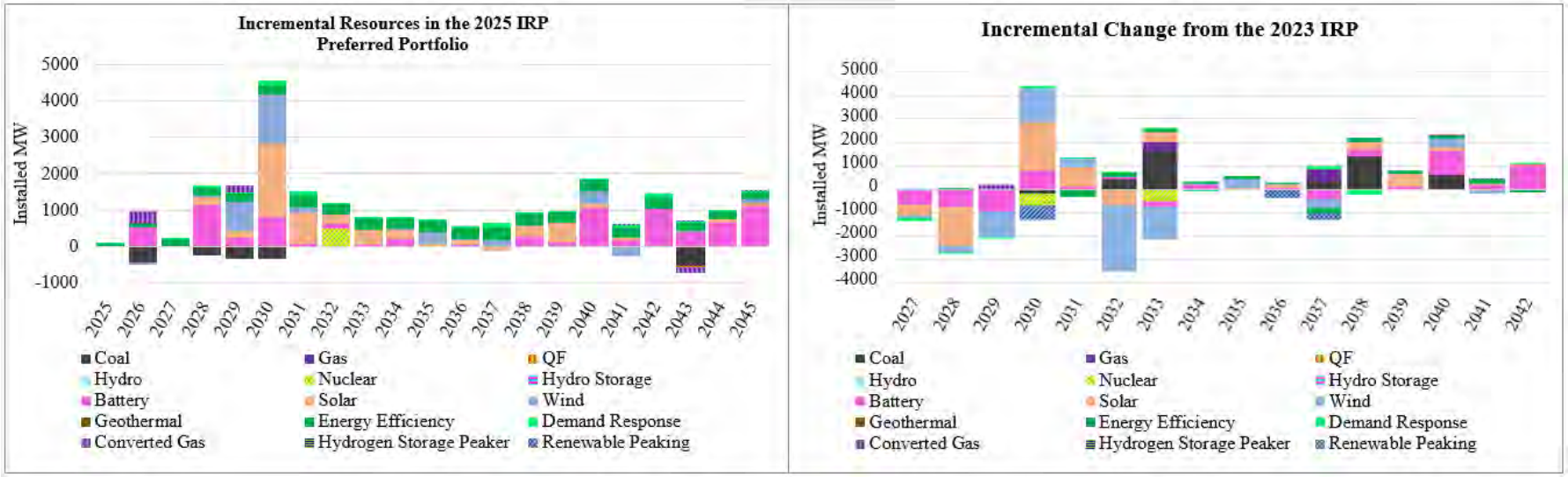
Action Item	6. Renewable Energy Credit (REC) Actions
6a	**Renewable Portfolio Standards (RPS):** • PacifiCorp may pursue unbundled REC RFPs and purchases to meet its state RPS compliance requirements. • PacifiCorp will issue RFPs seeking unbundled RECs that will qualify in meeting California RPS targets through 2026 and future compliance periods, as needed.
6b	**Renewable Energy Credit Sales:** • Maximize the sale of RECs that are not required to meet state RPS compliance obligations.

Progress on 2023 Action Plan

This section describes progress that has been made on previous action plan items documented in the 2023 IRP filed with state commissions on May 30, 2023. Many of these action items have been superseded in some form by items identified in the 2025 IRP action plan. The status for all action items from the 2025 IRP is summarized in Table 10.2.

Figure 10.1 below presents two views of incremental resource changes in the 2025 IRP preferred portfolio. The figure at left reports the incremental resource additions from the 2025 IRP preferred portfolio, whereas the figure at right illustrates how these selections differ from the incremental changes in the 2023 IRP preferred portfolio.[6, 7]

Figure 10.1 – Incremental Resources in the 2025 IRP Preferred Portfolio



[6] The timeframe presented in these charts shows only years where expansion resources were selected.

[7] These figures support Wyoming Public Service Commission Guideline E, "Changes in expected resource acquisitions and load growth from that presented in the utility's previous IRP". A load comparison is provided in Appendix A (Load Forecast), Figure A.1.

Table 10.2 – 2023 IRP Action Plan Status Update

Action Item	1. Existing Resource Actions	Status
1a	**Colstrip Units 3 and 4:** • PacifiCorp pursues a beneficial change in ownership agreements that will enable an exit from the Colstrip project in Montana by 2030.	• PacifiCorp continues to work with co-owners to develop the most cost-effective path toward an exit from the project.
1b	**Craig Unit 1:** • PacifiCorp will continue to work closely with co-owners to seek the most cost-effective path forward toward the 2023 IRP Update preferred portfolio target exit date of December 31, 2025.	• PacifiCorp continues to work with co-owners to develop the most cost-effective path toward an exit from the project.
1c	**Naughton Units 1 and 2 Gas Conversion:** • PacifiCorp will initiate the process of converting Naughton Units 1 and 2 to natural gas beginning Q2 2023, including obtaining all required regulatory notices and filings. Natural gas operations are anticipated to commence spring of 2026. • PacifiCorp will initiate the closure of the Naughton South Ash Pond no later than the end of December 2025 when coal operations cease, and will complete closure by October 17, 2028, as required under its pond closure extension submission.	• PacifiCorp is on track to complete required regulatory notices and filings to process the conversion of Naughton Units 1 and 2 from coal to natural gas. • Coal supply agreements for Naughton Units 1 and 2 will not be extended beyond the end of December 2025.
1d	**Jim Bridger Units 1 and 2 Gas Conversion:** • PacifiCorp has initiated the process of ending coal-fueled operations. The Wyoming Air Quality Division issued an air permit on December 28, 2022, for the natural gas conversion. All required regulatory notices and filings will be completed by end of 2023. • By the end of Q4 2023, PacifiCorp will administer termination, amendment, or close-out of existing permits, contracts, and other agreements.	• PacifiCorp received an approval order on December 7, 2023, from the Wyoming Public Service Commission for the conversion of Jim Bridger Units 1 and 2 from coal to natural gas. • PacifiCorp ceased coal-fueled operations at Jim Bridger Units 1 and 2 on December 31, 2023. • Removal of coal handling equipment and installation of natural gas components began on January 1, 2024. Conversions were completed in Q2 2024.

1e	**<u>Carbon Capture, Utilization, and Storage / Wyoming House Bill 200 Compliance:</u>** • PacifiCorp will complete an evaluation of the information received as part of the CCUS RFP and RFI processes by the end of Q3 2023. • PacifiCorp will submit, for Wyoming Public Service Commission approval, a final plan in compliance with the low-carbon energy portfolio standard no later than March 31, 2024.	• PacifiCorp completed its evaluation of information received as part of the CCUS RFP and RFI process in August of 2023. • PacifiCorp filed its final plan with the Wyoming Public Service Commission on March 29, 2024, as required under Wyoming House Bill 200.
1f	**<u>Regional Haze Compliance:</u>** • Following the resolution of first planning period regional haze compliance disputes, and the EPA's determination of the states' second planning period regional haze state implementation plans, PacifiCorp will evaluate and model any emission control retrofits, emission limitations, or utilization reductions that are required for coal units. • PacifiCorp will continue to engage with the EPA, state agencies, and stakeholders to achieve second planning period regional haze compliance outcomes that improve Class I visibility, provide environmental benefits, and are cost effective.	• Utah's first planning period disputes have been resolved. • Naughton and Wyodak's first planning period disputes have been resolved. The Tenth Circuit found EPA's disapproval of Wyoming's plan for Wyodak unlawful and remanded the plan to EPA for further review in accordance with the requirements of the Clean Air Act. No proposed rule has been issued to date. • Wyoming submitted its state-approved revised regional haze plan requiring the natural gas conversion of Jim Bridger Units 1 and 2 to EPA for approval. EPA is reviewing the state plan. PacifiCorp continues to comply with the state-approved plan and operating permits. • PacifiCorp continues to engage with the EPA, state agencies, and stakeholders relating to second planning period regional haze compliance. No second planning period requirements have been finalized by EPA to date.
1g	**<u>Natrium™ Demonstration Project:</u>**	• PacifiCorp continues to work with TerraPower on commercial arrangements for offtake from the

	• PacifiCorp will continue to monitor and report key TerraPower milestones for development and will make regulatory filings, as applicable. • By the end of 2023, PacifiCorp expects to finalize commercial agreements for the Natrium™ project. • By Q2 2024, PacifiCorp expects to develop a community action plan in coordination with community leaders. PacifiCorp will continue to monitor key TerraPower milestones for development and will make regulatory filings, as applicable, including, but not limited to, a request for the Public Utility Commission of Oregon to explicitly acknowledge an alternative acquisition method consistent with OAR 860-089-0100(3)(c), and a request for a waiver of a solicitation for a significant energy resource decision consistent with Utah statute 54-17-501.	Natrium™ project and expects to finalize these arrangements by the end of 2025.
1h	**<u>Ozone Transport Rule Compliance:</u>** • PacifiCorp will assess the impact of EPA's finalized Ozone Transport Rule from March 2023, relative to the assumptions contained in the 2023 IRP. • PacifiCorp will continue to engage with the EPA, state agencies, and stakeholders to achieve Ozone Transport Rule compliance outcomes that provide environmental benefits, support reliable energy delivery and are cost effective. • Based on the Ozone Transport Rule trading program and the associated benefits for reducing NOx emissions, PacifiCorp will install selective non-catalytic reduction retrofit equipment at the following units by 2026: Huntington Units 1 and 2, Hunter Units 1-3, and Wyodak. The Company will initiate procurement and permitting activities beginning Q2 2023.	• EPA finalized its approval of Wyoming's cross-state ozone state plan on December 19, 2023. This approval means PacifiCorp facilities in Wyoming are not subject to the federal ozone plan requirements. • The Tenth Circuit granted a motion to stay EPA's disapproval of Utah's state ozone plan. Utah is not subject to federal ozone requirements while the stay is in place. The Utah ozone case was transferred to the D.C. Circuit in February of 2024, for adjudication of the merits, leaving the stay in place.

Action Item	2. New Resource Actions	Status
2a	**Customer Preference Request for Proposals:** • PacifiCorp is continuously receiving and evaluating requests for voluntary customer programs in Utah and Oregon. PacifiCorp may use the marginal resources from ongoing 2022AS RFP and future request for proposals to fulfill customer need. In some cases, customer preference may necessitate issuance of a request for proposals to procure resources within the action plan window. • Consistent with Utah Community Renewable Energy Act, PacifiCorp continues to work with eligible communities to develop program to achieve the goal of being net 100% renewable by 2030; PacifiCorp anticipates filing an application for approval of the program with the Utah Public Service Commission in 2024 or 2025, which may necessitate issuance of a request for proposals to procure resources within the action plan window.	PacifiCorp and the eligible communities are meeting monthly to discuss program design. Subject to the finalization of the program details, PacifiCorp applied for approval of a resource solicitation process with the Utah Public Service Commission in November 2024.
2b	**2025 All-Source Request for Proposals:** • PacifiCorp will issue an all-source Request for Proposals (RFP) to procure resources aligned with the 2025 IRP preferred portfolio that can achieve commercial operations by the end of December 2030. • In Q4 2023, PacifiCorp will notify the Public Utility Commission of Oregon, the Public Service Commission of Utah, and the Washington Utilities and Transportation	The 2025 IRP includes an action item to procure incremental resources as needed to serve customers over the long term.

	Commission, of PacifiCorp's need for an independent evaluator. • In Q1 2024, PacifiCorp will file a draft all-source RFP with applicable state utility commissions. • In Q3 2024, PacifiCorp expects to receive approval of the all-source RFP from applicable state utility commissions and issue the RFP to the market. • In Q4 2024, PacifiCorp will identify a final shortlist from the all-source RFP, and file for approval of the final shortlist in Oregon. Similarly, PacifiCorp will make a filing in Utah for significant energy resources on final shortlist. PacifiCorp will file a certificate of public convenience and necessity (CPCN) applications, as applicable. • By Q1 2025 PacifiCorp will execute definitive agreements with winning bids from the all-source RFP. • Winning bids from the all-source RFP are expected to achieve commercial operation by December 31, 2028, or earlier.	
2c	**<u>2022 All-Source Request for Proposals:</u>** • In April 2022 PacifiCorp issued an all-source Request for Proposals to procure resources that can achieve commercial operations by the end of December 2027. • In Q2 2023, PacifiCorp will identify a final shortlist from the all-source RFP, and file for approval of the final shortlist in Oregon. Similarly, PacifiCorp will make a filing in Utah for any applicable significant energy resources on final shortlist. PacifiCorp will file	• PacifiCorp suspended the 2022 All-Source RFP in September 2023 to further evaluate how key changes in the planning environment might influence long-term resource procurement activities. • EPA's approval of Wyoming's cross-state ozone transport rule plan and the Tenth Circuit Court's stay of Utah's ozone plan have materially impacted the need for the type and volume of resources identified in the 2023 IRP preferred portfolio, which considered resource

	certificate of public convenience and necessity (CPCN) applications, as applicable, and • By Q4 2023 PacifiCorp will execute definitive agreements with winning bids from the all-source RFP. • Winning bids from the 2022 all-source RFP are expected to achieve commercial operation by December 31, 2027, or earlier.	procurement needs coming out of the 2022 All-Source Request for Proposals. • PacifiCorp contracted on a bi-lateral basis for battery energy storage resources with commercial operation dates prior to summer 2026 and terminated the 2022 All Source Request for Proposals.
Action Item	3. **Transmission Action Items**	**Status**
3a	**<u>Energy Gateway South Segment F (Aeolus-Clover 500 kV transmission line):</u>** • In Q4 2024, construction of Energy Gateway South is expected to be completed and placed in service.	The Energy Gateway South transmission project is in-service.
3b	**<u>Energy Gateway West, Segment D.1 (Windstar-Shirley Basin 230 kV transmission line):</u>** • In Q4 2024, construction of Energy Gateway West segment D.1 to be completed and placed in service in Q4 2024 •	The Energy Gateway West Sub-Segment D1 transmission project is in-service.
3c	**<u>Boardman-to-Hemingway (500 kV transmission line):</u>** • Continue to support the project under the conditions of the Boardman-to-Hemingway Transmission Project (B2H) Joint Permit Funding Agreement. • Continue to participate in the development and negotiations of the construction agreement. • Continue to participate in "pre-construction" activities in support of the 2026-2027 in-service date.	PacifiCorp has continued to participate in the support, negotiations, planning and permitting of the Boardman-to-Hemingway 500 kilovolt transmission line, which is targeted for a 2027 in-service date.

	• Continue negotiations for plan of service post B2H for parties to the permitting agreement.	
3d	Initiate Local Reinforcement Projects as identified with the addition of new resources per the preferred portfolio, and follow-on requests for proposal successful bids	Reinforcements have been identified. A final assessment of upgrades is pending signed agreements.
3e	Continue permitting support for Gateway West segments D.3 and E. Initiate preliminary permitting and development activities for future transmission investments not currently included in the preferred portfolio. These future transmission projects can include development of additional Energy Gateway segments and exploration of new routes that have connections to other regions (i.e., connecting southern Oregon to the east with connections to the desert southwest). These activities will enable PacifiCorp to prepare for potential growth in new large loads seeking new service over the next decade.	PacifiCorp continues permitting efforts on both segments D.3 and E, maintaining the record of decision on each segment.

Action Item	4. **Demand-Side Management (DSM) Actions**	**Status**
4a	**<u>Energy Efficiency Targets:</u>** • PacifiCorp will acquire cost-effective energy efficiency resources targeting annual system energy and capacity selections from the preferred portfolio as summarized below. PacifiCorp's state-specific processes for planning for DSM acquisitions is provided in Appendix D in Volume II of the 2023 IRP.	For energy efficiency, PacifiCorp achieved the Action Plan target of 543 GWh in 2023 and achieved 96.2% of the 2024 target, excluding HERs. Since the 2023 IRP, PacifiCorp launched demand response programs and expanded offerings within its existing programs. PacifiCorp continues to pursue the incremental capacity additions but did not achieve the 2023-24 incremental capacity, due to the later than anticipated timing of program effective dates for newly launched demand response programs.

Year	1st year Energy Efficiency (GWh)	Annual Capacity (MW)
2023	543	123
2024	559	220
2025	568	259
2026	628	197

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- PacifiCorp will pursue cost-effective demand response resources targeting annual system capacity selections from the preferred portfolio as summarized in Appendix D in Volume II of the 2023 IRP.

Year	Annual Incremental Capacity (MW)
2023	72
2024	39
2025	152
2026	109

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<tr><th>Action Item</th><th>5. Market Purchases</th><th>Status</th></tr>
<tr><td>5a</td><td>

<u>Market Purchases:</u>

- Acquire short-term firm market purchases for on-peak delivery from 2023-2025 consistent with the Risk Management Policy and Energy Supply Management Front Office Procedures and Practices. These short-term firm market purchases will be acquired through multiple means: Balance of month and day-ahead brokered transactions in which the broker provides a competitive price.
- Balance of month, day-ahead, and hour-ahead transactions executed through an exchange, such as the Intercontinental Exchange, in which the exchange provides a competitive price.
- Prompt-month, balance-of-month, day-ahead, and hour-ahead non-brokered bi-lateral transactions.

</td><td>

Since the publication of the 2023 IRP action plan, PacifiCorp has continued to transact consistent with its risk management and energy supply procedures to reliably cost-effectively serve customer requirements. Such transactions include seeking competitive pricing to acquire short-term firm purchases, execute balance of month, day-ahead and hour-ahead transactions through exchanges, and engage in prompt-month, balance-of-month, day-ahead and hour-ahead non-brokered bi-lateral transactions.

Market purchases are made in accordance with the Risk Management Policy and Energy Supply Management Front Office Procedures and Practices and include a mix of the transaction types identified in item 5a.

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Action Item	6. **Renewable Energy Credit (REC) Actions**	Status

6a	**Renewable Portfolio Standards (RPS):** • PacifiCorp will pursue unbundled REC RFPs and purchases to meet its state RPS compliance requirements. • As needed, issue RFPs seeking unbundled RECs that will qualify in meeting California RPS targets through 2024 and future compliance periods as needed.	PacifiCorp will continue to evaluate the need for unbundled RECs and issue RFPs to meet its state RPS compliance requirements as needed.
6b	**Renewable Energy Credit Sales:** • Maximize the sale of RECs that are not required to meet state RPS compliance obligations.	PacifiCorp will continue to issue reverse RFPs to maximize the sale of RECs that are not required to meet state RPS compliance obligations

Acquisition Path Analysis

Resource and Compliance Strategies

PacifiCorp worked with stakeholders to define its portfolio development process and cost and risk analysis in the 2025 IRP. This analysis reflects a combination of specific planning assumptions related to key uncertainties addressed in the acquisition path analysis including load, private generation, changes in available resources, and emissions polices. PacifiCorp will further analyze sensitivity cases on planning assumptions related primarily to the load forecasts and private generation penetration levels. The array of planning assumptions that define the studies used to develop resource portfolios provides the framework for a resource acquisition path analysis by evaluating how resource selections are impacted by changes to planning assumptions.

Given current load expectations, portfolio modeling performed for the 2025 IRP shows the resource acquisition path in the preferred portfolio is robust among a wide range of policy and market conditions, particularly in the near-term, when cost-effective renewable resources qualifying for federal income tax credits, market purchases, and energy efficiency and demand response resources are consistently selected, in conjunction with new storage and continued thermal unit operations to mitigate volatility. With regard to renewable resource acquisition, the portfolio development modeling performed in the 2025 IRP shows that new renewable resource needs are driven primarily by economics and reliability. Beyond load, state and federal environmental policy also influences resource selections in the 2025 IRP. For these reasons, the acquisition path analysis focuses on economic, load, reliability, and environmental policy trigger events that would require alternative resource acquisition strategies. For each trigger event in Table 10.3, PacifiCorp identifies the planning scenario assumption affecting both short-term (2025-2034) and long-term (2035-2045) resource strategies.

Acquisition Path Decision Mechanism

The Public Service Commission of Utah requires that PacifiCorp provide "[a] plan of different resource acquisition paths with a decision mechanism to select among and modify as the future unfolds."[8] PacifiCorp's decision mechanism is centered on the IRP process and ongoing updates to the IRP modeling tools between IRP cycles. The same modeling tools used in the IRP are also used to evaluate and inform the procurement of resources. The IRP models are used on a macro-level to evaluate alternative portfolios and futures as part of the IRP process, and then on a micro-level to evaluate the economics and system benefits of individual resources as part of the supply-side resource procurement and demand-side management target-setting/valuation processes. PacifiCorp uses the IRP development process and the IRP modeling tools to serve as decision support tools to guide prudent resource acquisition paths that maintain system reliability and flexibility at a reasonable cost.

PacifiCorp's 2025 IRP acquisition path analysis provides insight on how changes in the planning environment might influence future resource procurement activities. Changes in procurement activities driven by changes in the planning environment will ultimately be reflected in future IRPs and resource procurement decisions.

[8] Public Service Commission of Utah, In the Matter of Analysis of an Integrated Resource Plan for PacifiCorp, Report and Order, Docket No. 90-2035-01, June 1992, p. 28.

Table 10.3 – Near-term and Long-term Resource Acquisition Paths

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2025-2034)	Long Term Resource Acquisition Strategy (2035-2045)
Higher sustained load growth	Refer to Chapter 8, Table 8.7 – Sensitivity Case Definitions sensitivity "High Load Growth"	• A new load forecast incorporating higher than anticipated load growth increases load relative to the base forecast. • Through 2030, resource additions would be similar to the preferred portfolio with a small amount of additional wind and solar added to the portfolio to meet higher than anticipated loads. • From 2031 through 2034, small amounts of solar, 4-hour battery and DSM resources are added to meet higher than anticipated loads.	• In the long-term acquisition window, slightly fewer incremental resources are required due to additional incremental resources shifting into the near-term window to meet higher than anticipated loads compared to the preferred portfolio.
Lower sustained load growth	Refer to Chapter 8, Table 8.7 – Sensitivity Case Definitions sensitivity "Low Load Growth".	• A new load forecast incorporating lower than anticipated load growth decreases load relative to the base forecast. • In the near-term acquisition window, far fewer incremental resources are required to meet load compared to the preferred portfolio. • Through 2034, significant amounts of wind and solar along with moderate amounts of small-scale solar and 100-hour battery fall out of the portfolio while additional 4-hour battery is added compared to the preferred portfolio. • Fewer incremental transmission options are required to meet fewer incremental resources while the timing of some incremental transmission options is shifted outward compared to the preferred portfolio.	• In the long-term acquisition window, even fewer incremental resources are required due to lower loads compared to the preferred portfolio. • From 2035-2045, significant amounts of wind, solar, small-scale solar and 100-hour battery fall out of the portfolio compared to the preferred portfolio and would not need to be procured.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2025-2034)	Long Term Resource Acquisition Strategy (2035-2045)
Higher sustained private generation penetration levels	Refer to Chapter 8, Table 8.7 – Sensitivity Case Definitions sensitivity "High Private Generation"	• A new load forecast incorporating higher than anticipated private generation adoption decreases load relative to the base forecast. • In response to high private generation adoption, far fewer incremental resource selections are required in the action plan window compared to the preferred portfolio. • Through 2030, significant amounts of wind, solar, small-scale solar and moderate amounts of 100-hour battery fall out of the preferred portfolio while a significant amount of 4-hour battery is selected. • Through the remainder of the near-term acquisition window, resource additions are similar to the preferred portfolio. • Transmission selections are similar to the preferred portfolio with the location and timing of incremental transmission changing depending on incremental resource selections.	• From 2035-2045, higher private generation results in 2,696 MW of resource additions falling out of the portfolio compared to the preferred portfolio. • On average, far less wind, solar and 100-hour air battery are selected while additional 4-hour battery is selected in similar amounts compared to the preferred portfolio.
Lower sustained private generation penetration levels	Refer to Chapter 8, Table 8.7 – Sensitivity Case Definitions sensitivity "Low Private Generation"	• A new load forecast incorporating lower than anticipated private generation adoption increases load relative to the base forecast. • To counteract low private generation adoption, minimal additional resources are required relative to the preferred portfolio through 2029. • From 2030 through 2034, moderate amounts of wind and solar are added to what is selected in the preferred portfolio.	• In the long-term resource acquisition window, resource selections are similar to the preferred portfolio as lower private generation levels cause incremental resource builds in the near-term acquisition window. • 156 MW of Naughton gas conversion would remain online compared to retiring in 2043 in the preferred portfolio.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2025-2034)	Long Term Resource Acquisition Strategy (2035-2045)
Higher than expected large-metered load growth	Refer to Chapter 8, Table 8.7 – Sensitivity Case Definitions sensitivity "Large Metered Load Growth"	• A new load forecast incorporating higher than anticipated large-metered load growth beginning in 2027 increases load relative to the base forecast. • High large-metered load growth results in significant resource additions compared to the preferred portfolio, including significant resource additions in the near-term acquisition window. • By 2028, nearly 10,000 MW of additional resources are selected compared to the preferred portfolio including significant amounts of wind, solar, small-scale solar, 4-hour battery and a moderate amount of 8-hour battery. • By the end of 2034, a significant amount of new gas is added to the portfolio, along with nearly 4,500 MW of additional incremental renewable resources. • Significant transmission investment would be required to serve new resource additions.	• From 2035-2045, significant additional resources are required compared to the preferred portfolio including more than 1,000 MW of new gas and 5,000 MW of new renewables.
Changes to IRA/IIJA result in lower-than-expected renewable costs	Refer to Chapter 8, Table 8.7 – Sensitivity Case Definitions sensitivity "Low-Cost Renewables"	• High adoption of the IRA/IIJA resulting in lower-than-expected new renewable resource costs would result in significantly more incremental renewable resource additions than selected in the preferred portfolio. • Significant incremental wind, solar and 4-hour battery additions would result in lower thermal output and less 100-hour battery storage additions. • Significant transmission investment would be required to serve new resource additions.	• From 2035-20445, significant additional incremental renewable resources would be built along with more incremental transmission. • Thermal resources would run at lower capacity factors with some thermal capacity retiring in the long-term acquisition window.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2025-2034)	Long Term Resource Acquisition Strategy (2035-2045)
Changes to IRA/IIJA result in higher-than-expected renewable costs	Refer to Chapter 8, Table 8.7 – Sensitivity Case Definitions sensitivity "Low PTC/ITC eligibility"	• In the absence of tax credits from the IRA/IIJA resulting in higher-than-expected renewable resource costs, significant amounts of incremental renewable resource additions would fall out of the portfolio compared to the preferred portfolio. • By 2030, significant wind, solar, small-scale solar and 100-hour iron battery would fall out from the portfolio. • By the end of 2034, significant additional incremental renewable capacity falls out of the portfolio while some new gas is selected. • If renewable resources become more expensive in the absence of IRA/IIJA benefits, very little capacity would be needed to replace renewable capacity as thermal resources would run at higher capacity factors to meet load obligations.	• In the long-term acquisition window, additional new gas is built along with a small amount of gas peaking to replace lost renewables from the preferred portfolio. • Existing thermal resources would remain online past retirement dates selected in the preferred portfolio to continue providing energy and capacity.
No legislation under consideration is adopted and state environmental requirements impacting thermal plants are unwound	Refer to Chapter 8, Table 8.7 – Sensitivity Case Definitions sensitivity "Business as Usual" (also called the Wyoming Reference Case).	• With only load requirements to meet (no other federal or state requirements), far fewer resources are selected compared to the preferred portfolio as existing thermal resources are able to run at higher capacity factors and less capacity and energy is needed on the system. • In the near-term acquisition window, significantly fewer MW are selected compared to the preferred portfolio, including less wind, solar, small-scale solar, 4-hour battery and 100-hour battery. • With far fewer new resources compared to the preferred portfolio, "business as usual" would require significantly fewer incremental transmission interconnect MW in the near-term acquisition window.	• From 2035-2045, significantly fewer MW are selected compared to the preferred portfolio including less wind, solar, small-scale solar and 100-hour battery. • Additional 4-hour battery is added from 2035 through 2045 compared to the preferred portfolio, revealing that in a "business as usual" scenario, 4-hour batteries remain valuable new resource options in the absence of other new renewables.
Legislation forces all coal to retire or gas convert by 2032	Refer to Chapter 8, Table 8.5 – Portfolio Variants variant "No Coal 2032"	• With all coal units forced to retire or gas convert by 1/1/2032, 2,679 MW of nameplate capacity would convert to natural gas in 2030. Jim Bridger units 3 and 4 were assumed to not be allowed to install CCS, and in this case, units 3 and 4 would convert to natural gas in 2030 instead of retiring. • By 1/1/2032, 686 MW of coal retires. • Significant additional incremental renewable resources and are added to the portfolio including wind, solar, 4-hour battery and 100-hour battery within the near-term acquisition window.	• In the long-term acquisition window resource additions are similar to the preferred portfolio.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2025-2034)	Long Term Resource Acquisition Strategy (2035-2045)
No Natrium™ Advanced Nuclear Demonstration Project in 2032, and no other nuclear projects	Refer to Chapter 8, Table 8.5 – Portfolio Variants variant "No Nuclear"	• Without the 500 MW Natrium™ demonstration project in 2032, moderate amounts of renewable resources are added to the portfolio by 2032. • In 2033 and 2034, additional incremental renewable resources are added to the portfolio.	• While the type, timing and location of resources change, the amount of incremental resource additions in the long-term acquisition window without Natrium™ is similar to the preferred portfolio. • Batteries and other renewables would fall out of the portfolio in 2041 through 2045 as incremental amounts of these resources are built earlier to replace Natrium™. • 682 MW of thermal resources would remain online in 2043 instead of retiring, including 526 MW of Jim Bridger CCS and 156 MW of Naughton gas conversion.
Technologies such as nuclear, hydrogen storage, 100-hour battery storage and biodiesel peaking do not become commercially viable	Refer to Chapter 8, Table 8.5 – Portfolio Variants variant "No Forward Technology"	• Without nuclear, hydrogen storage, 100-hour battery or biodiesel peaking, nuclear and 100-hour battery selected in the preferred portfolio are replaced by a significant amount of 4-hour battery and moderate amounts of wind and solar. • In the near-term acquisition window, the capacity of future technology that falls out of the portfolio is greater than the capacity of incremental resources needed to replace the lost capacity.	• While the type, timing and location of resources change as is required by the absence of nuclear and 100-hour battery, the amount of incremental resource additions in the long-term acquisition window is similar to the preferred portfolio. • 682 MW of thermal resources would remain online in 2043 instead of retiring, including 526 MW of Jim Bridger CCS and 156 MW of Naughton gas conversion.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2025-2034)	Long Term Resource Acquisition Strategy (2035-2045)
Legislation requires the Hunter plant to retire no later than 1/1/2030	Refer to Chapter 8, Table 8.5 – Portfolio Variants variant "Hunter Retire"	• By 1/1/2030, 1,158 MW of nameplate coal capacity retires at Hunter. • To replace the lost Hunter capacity, by 2030, moderate amounts of wind and solar would be added to the portfolio, including solar at Hunter. Additionally, a significant amount of 4-hour battery and moderate amount of 100-hour battery would be added to the portfolio.	• From 2035-2045, moderate amounts of incremental resource additions would be added to the portfolio, including new gas. • In 2043, 156 MW of nameplate capacity at Naughton 1 running as gas remains online through the end of the planning horizon instead of retiring as it does in the preferred portfolio.
No CCS available at Jim Bridger in 2030	Refer to Chapter 8, Table 8.5 – Portfolio Variants variant "No CCS"	• Incremental resource selections with Jim Bridger CCS unavailable are similar to the preferred portfolio with slight changes in the location and timing of incremental resources. • By 1/1/2030, 174 MW of nameplate capacity remains available at Jim Bridger without the installation of CCS. • Moderate amounts of wind and solar, some of which is sited at Jim Bridger, falls out of the portfolio, along with some 4-hour battery.	• From 2039-2045 fewer 4-hour battery resources are selected. • In 2043, 247 MW of Naughton gas conversion retires without CCS in the portfolio.

Procurement Delays

The main procurement risk, where a procurement need is indicated, is an inability to procure resources in the required timeframe to maintain reliable resilient grid operations and statutory compliance. There are various reasons why a particular proxy resource cannot be procured in the timeframe identified in a given action plan period. There may not be any cost-effective opportunities available through an RFP, the successful RFP bidder may experience delays in permitting and/or default on their obligations, there may be insufficient potential resource development deliverable to the jurisdiction with resource need, or there might be a material and sudden change in the market for fuel and materials. Moreover, there is always the risk of unforeseen environmental or other electric utility regulations that may influence the PacifiCorp's entire resource procurement strategy.

As the range of events is unknowable, these potential impacts are represented by broad sensitivity studies such as those which raise or lower resource availability (such as natrium, carbon capture, coal, offshore wind) and competition for resources (load, distributed generation, IRA adoption, DSM). In addition, IRP resource potential availability is informed by an assessment of publicly available data derived from the cluster study process.

Possible paths PacifiCorp could take in the event of a procurement delay or sudden change in procurement need can include combinations of the following:

- In circumstances where PacifiCorp is engaged in an active RFP where a specific bidder is unable to perform, alternative bids can be pursued.
- PacifiCorp can issue an emergency RFP for a specific resource and with specified availability.
- PacifiCorp can seek to negotiate an accelerated delivery date of a potential resource with the supplier/developer.
- PacifiCorp can seek to procure near-term purchased power and transmission until a longer-term alternative is identified, acquired through customized market RFPs, exchange transactions, brokered transactions or bi-lateral, sole source procurement.
- Accelerate acquisition timelines for direct load control programs.
- Procure and install temporary generators to address some or all the capacity needs.
- Temporarily drop below its planning reserve margin.
- Implement load control initiatives, including calls for load curtailment via existing load curtailment contracts.

IRP Action Plan Linkage to Business Planning

Consistent with the Utah commission's order in Docket No. 15-035-04, the IRP is directed to include a business plan sensitivity. In the 2025 IRP, a distinct sensitivity would be redundant because the integrated preferred portfolio's base assumptions are aligned with the business plan as set forth the following parameters:

- Over the first three years, resources align with those assumed in PacifiCorp's current Business Plan.

- Beyond the first three years of the study period, unit retirement assumptions are aligned with the preferred portfolio.
- All other resources are optimized.

Consequently, please refer to the 2025 IRP preferred portfolio as described in Chapter 9.

Resource Procurement Strategy

To acquire resources outlined in the 2025 IRP action plan, PacifiCorp intends to continue using competitive solicitation processes in accordance with applicable laws, rules, and/or guidelines in each of the states in which PacifiCorp operates if jurisdictional need is warranted. PacifiCorp will also continue to pursue opportunistic acquisitions identified outside of a competitive procurement process that provide benefits to customers. Regardless of the method for acquiring resources, PacifiCorp will support its resource procurement activities with the appropriate financial analysis using then-current assumptions for inputs to include but not limited to load forecasts, commodity prices, resource costs, and policy developments. Any such financial analysis will account for any applicable long-term system benefits with least-cost, least-risk planning principles in mind. The sections below profile the general procurement approaches for the key resource categories covered in the 2025 IRP action plan.

Renewable Resources, Storage Resources, and Dispatchable Resources

PacifiCorp will use competitive RFPs to procure supply-side resources consistent applicable laws, rules, and/or guidelines in each of the states in which PacifiCorp operates. In Oregon and Utah, these state requirements involve the oversight of an independent evaluator. In Washington, an independent evaluator may be used if benchmark resources (PacifiCorp built and owned resources) are being considered after consultation with Washington staff and stakeholders. The all-source RFPs outline the types of resources being pursued, defines specific information required of potential bidders and details both price and non-price scoring metrics that will be used to evaluate proposals.

Renewable Energy Credits

PacifiCorp uses shelf RFPs as the primary mechanism under which REC RFPs and reverse REC RFPs will be issued to the market. The shelf RFPs are updated to define the product definition, timing, and volume and further provide schedule and other applicable criteria to bidders.

Demand-Side Management[9]

PacifiCorp offers a robust portfolio of demand response and energy efficiency programs and initiatives, most of which are offered in multiple states, depending on size of the opportunity and the need. Programs are reassessed on a regular basis. PacifiCorp provides Class 4 DSM offerings and has continued Wattsmart outreach and communications. Educating customers regarding

[9] Class 1 DSM is most commonly referred to as “demand response” in the 2023 IRP; Class 2 DSM is most commonly referred to as “energy efficiency”. Class 4 DSM describes energy efficiency measures achieved through public outreach and education.

energy efficiency and load management opportunities is an important component of PacifiCorp's long-term resource acquisition plan. PacifiCorp will continue to evaluate how to best incorporate potential DSM programs into the broader all-source RFP process discussed above or whether separate RFPs focused on these resources are warranted based on state-specific requirements and program needs.

Small Scale Renewable Energy Supply

In order to fulfil Oregon regulatory requirements for small-scale renewable resources, PacifiCorp plans to issue a small-scale renewable energy RFP in June 2025 to solicit resources within its territory which are 20 MW or smaller and can be commercially operational by December 2029. Currently, Oregon's new HB 2021 legislation and associated Clean Energy Plan is driving a specific evaluation of small-scale renewables that may help to identify the costs and benefits of smaller (20 MW or less installed capacity) community-oriented renewables projects across PacifiCorp's service territory. This study is discussed in Appendix P (Oregon Clean Energy Update) and will be further addressed in PacifiCorp's 2025 Oregon Clean Energy Plan.

Assessment of Owning Assets versus Purchasing Power

As PacifiCorp acquires new resources, it will need to determine whether it is better to own a resource or purchase power from another party. While the ultimate decision will be made at the time resources are acquired, and will primarily be based on cost, there are other considerations that may be relevant.

With owned resources, PacifiCorp is in a better position to control costs, make life extension improvements (as was implemented with the wind repower project), use the site for additional resources in the future, change fueling strategies or sources (as was implemented for the Naughton Unit 3 gas conversion and as planned for Jim Bridger Units 1 and 2), efficiently address plant modifications that may be required as a result of changes in environmental or other laws and regulations, and use the plant at embedded cost as long as it remains economic. In addition, by owning a plant, PacifiCorp can hedge itself against the uncertainty of third-party performance consistent with the terms and conditions outlined in a power-purchase agreement over time. Because of recent downgrades by credit rating agencies, the increase in debt associated with owned resources could negatively impact PacifiCorp's credit ratios and credit rating.

Alternately and depending on contractual terms, purchasing power from a third party in a long-term contract may help mitigate and may avoid liabilities associated with closure of a plant. A long-term power-purchase agreement relinquishes control of construction cost, schedule, ongoing costs and environmental and regulatory compliance. Power-purchase agreements can also protect and cap the buyer's exposure to events that may not cover actual seller financial impacts. However, credit rating agencies can impute debt associated with long-term resource contracts that may result from a competitive procurement process. The level of debt imputation associated with long-term contracts will have an impact on PacifiCorp's credit ratios and credit rating.

Managing Carbon Risk for Existing Plants

CO_2 reduction regulations at the federal, regional, or state levels could prompt PacifiCorp to continue to look for measures to lower CO_2 emissions of fossil-fired power plants through cost-effective means. The cost, timing, and compliance flexibility afforded by CO_2 reduction rules will impact what types of measures might be cost effective and practical from operational and regulatory perspectives.

Compliance strategies will be affected by how and whether states or the federal government choose to implement further policies related to greenhouse gases and nitrogen oxide. State or federal frameworks could impute a carbon tax or implement a cap-and-trade framework. Under a cap-and-trade policy framework, examples of factors affecting carbon compliance strategies include the allocation of emission allowances, the cost of allowances in the market, and any flexible compliance mechanisms such as opportunities to use carbon offsets, allowance/offset banking and borrowing, and safety valve mechanisms. Under a CO_2 tax framework, the tax level and details around how the tax might be assessed would affect compliance strategies.

To lower the emission levels for existing fossil-fired power plants, options include changes in plant dispatch, unit retirements, changing the fuel type, deployment of plant efficiency improvement projects, and adoption of new technologies such as CO_2 capture with sequestration. As mentioned above, plant CO_2 emission risk may also be addressed by acquiring offsets or other environmental attributes that could become available in the market under certain regulatory frameworks. PacifiCorp's compliance strategies will evolve and continue to be reassessed in future IRP cycles as market forces and regulatory outcomes evolve.

Purpose of Hedging

While PacifiCorp focuses every day on minimizing net power costs for customers, the company also focuses every day on mitigating price risk to customers, which is done through hedging consistent with a robust risk management policy. For years PacifiCorp has followed a consistent hedging program that limits risk to customers, has tracked risk metrics assiduously and has diligently documented hedging activities. PacifiCorp's risk management policy and hedging program exists to achieve the following goals: (1) ensure reliable sources of electric power are available to meet PacifiCorp's customers' needs; and (2) reduce volatility of net power costs for PacifiCorp's customers. PacifiCorp does not engage in a material amount of proprietary trading activities. Hedging modifies the potential losses and gains in net power costs associated with wholesale market price changes. The purpose of hedging is not to reduce or minimize net power costs. PacifiCorp cannot predict the direction or sustainability of changes in forward prices. Therefore, PacifiCorp hedges, in the forward market, to reduce the volatility of net power costs consistent with good industry practice as documented in the company's risk management policy.

Risk Management Policy and Hedging Program

PacifiCorp's risk management policy and hedging program were designed to follow electric industry best practices and are reviewed at least annually by the company's risk oversight committee. The risk oversight committee includes PacifiCorp representatives from the front office, finance, risk management, treasury, and legal department. The risk oversight committee makes

recommendations to the chief executive officer of PacifiCorp, who ultimately must approve any change to the risk management policy.

The main components of PacifiCorp's risk management policy and hedging program are natural gas percent hedged volume limits and power volume hedge limits. These limits force PacifiCorp to monitor the open positions it holds in power and natural gas on behalf of its customers on a daily basis and limit the size of short positions by prescribed time frames in order to reduce customer exposure to price concentration and price volatility. The hedge program requires purchases of natural gas and power at fixed prices in gradual stages in advance of when it is required to reduce the size of short positions and associated customer risk.

Dollar cost averaging is the term used to describe gradually hedging over a period of time rather than all at once. This method of hedging, which is widely used by many utilities, captures time diversification and eliminates speculative bursts of market timing activity. Its use means that at times PacifiCorp buys at relatively higher prices and at other times relatively lower prices, essentially capturing an array of prices at many levels. While doing so, PacifiCorp steadily and adaptively meets its hedge goals through the use of this technique while staying within power volume hedge limits and natural gas percent hedge volume limits.

Cost Minimization

While hedging does not minimize net power costs, PacifiCorp takes many actions to minimize net power costs for customers. First, the company is engaged in integrated resource planning to plan resource acquisitions that are anticipated to provide the lowest cost resources to our customers in the long run. PacifiCorp then issues competitive requests for proposals to assure that the resources we acquire are the lowest cost resources available on a risk-adjusted basis. In operations, PacifiCorp optimizes its portfolio of resources on behalf of customers by maintaining and operating a portfolio of assets that diversifies customer exposure to fuel, power market and emissions risk and utilize an extensive transmission network that provides access to markets across the western United States. Independent of any natural gas and electric price hedging activity, to provide reliable supply and minimize net power costs for customers, PacifiCorp commits generation units daily, dispatches in real time all economic generation resources and all must-take contract resources, serves retail load, and then sells any excess generation to generate wholesale revenue to reduce net power costs for customers. PacifiCorp also purchases power when it is less expensive to purchase power than to generate power from our owned and contracted resources.

Hedging cannot be used to minimize net power costs. Hedging does not produce a different expected outcome than not hedging and therefore cannot be considered a cost minimization tool. Hedging is solely a tool to mitigate customer exposure to net power cost volatility and the risk of adverse price movement. However, PacifiCorp does minimize the cost of hedging by transacting in liquid markets and utilizing robust protections to mitigate the risk of counterparty default.

Portfolio

PacifiCorp has a short position in natural gas because of its ownership of gas-fired electric generation that requires it to purchase large quantities of natural gas to generate electricity to serve its customers. PacifiCorp may have short or long positions in power depending on the shortfall or excess of the company's total generation capacity relative to customer load requirements at a given point in time.

Instruments

PacifiCorp's hedging program allows the use of several instruments including financial swaps, fixed price physical and options for these products. PacifiCorp chooses instruments that generally have greater liquidity and lower transaction costs.

Treatment of Customer and Investor Risks

The IRP standards and guidelines in Utah require that PacifiCorp "identify which risks will be borne by ratepayers and which will be borne by shareholders." This section addresses this requirement. Three types of risk are covered: stochastic risk, capital cost risk, and scenario risk.

Stochastic Risk Assessment

Several of the uncertain variables that pose cost risks to different IRP resource portfolios are quantified in the IRP production cost model using historic years to represent uncertainty. The variables addressed with such tools include retail loads, natural gas prices, wholesale electricity prices, hydroelectric generation, and thermal unit availability. Changes in these variables that occur over the long-term are typically reflected in normalized revenue requirements and are thus borne by customers. Unexpected variations in these elements are normally not fully reflected in rates and are therefore borne by investors unless specific regulatory mechanisms provide otherwise. Consequently, over time, these risks are shared between customers and investors. Between rate cases, investors bear these risks. Over a period of years, changes in prudently incurred costs will be reflected in rates and customers will bear the risk.

Capital Cost Risks

The actual cost of a generating or transmission asset is expected to vary from the cost assumed in the IRP. State commissions may determine that a portion of the cost of an asset was imprudent and therefore should not be included in the determination of rates. The risk of such a determination is borne by investors. To the extent that capital costs vary from those assumed in this IRP for reasons that do not reflect imprudence by PacifiCorp, the risks are borne by customers.

Scenario Risk Assessment

Scenario risk assessment pertains to abrupt or fundamental changes to variables that are appropriately handled by scenario analysis as opposed to representation by a statistical process or expected-value forecast. The single most important scenario risks of this type facing PacifiCorp continue to be government actions related to emissions and changes in load and transmission

infrastructure. These scenario risks relate to the uncertainty in predicting the scope, timing, and cost impact of emission and policies and renewable standard compliance rules.

To address these risks, PacifiCorp evaluates resources in the IRP and for competitive procurements using a range of CO_2 policy assumptions consistent with the scenario analysis methodology adopted for PacifiCorp's 2025 IRP portfolio development and evaluation process. The company's use of IRP sensitivity analysis covering different resource policy and cost assumptions also addresses the need for consideration of scenario risks for long-term resource planning. The extent to which future regulatory policy shifts do not align with PacifiCorp's resource investments determined to be prudent by state commissions is a risk borne by customers.