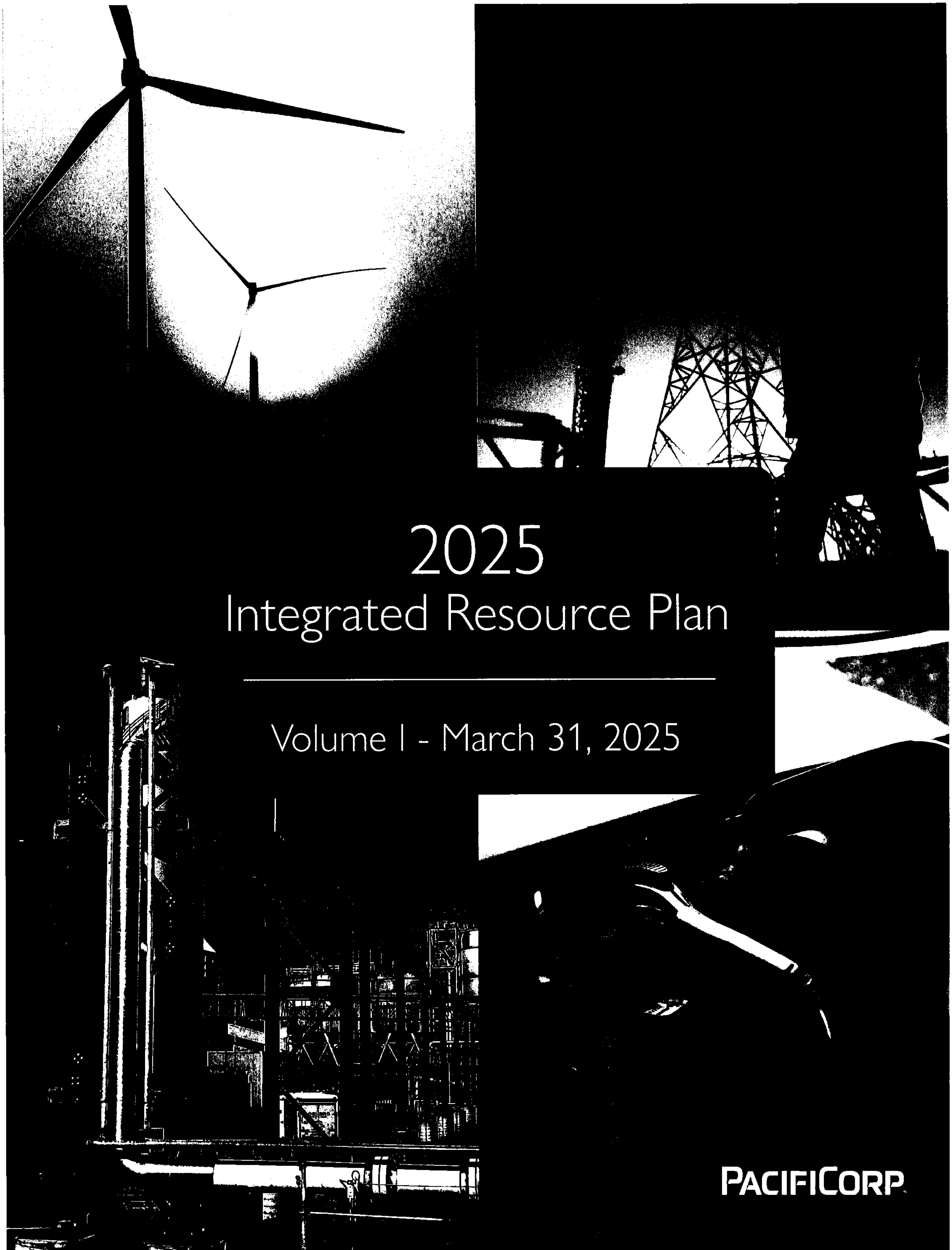

2025 Integrated Resource Plan

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

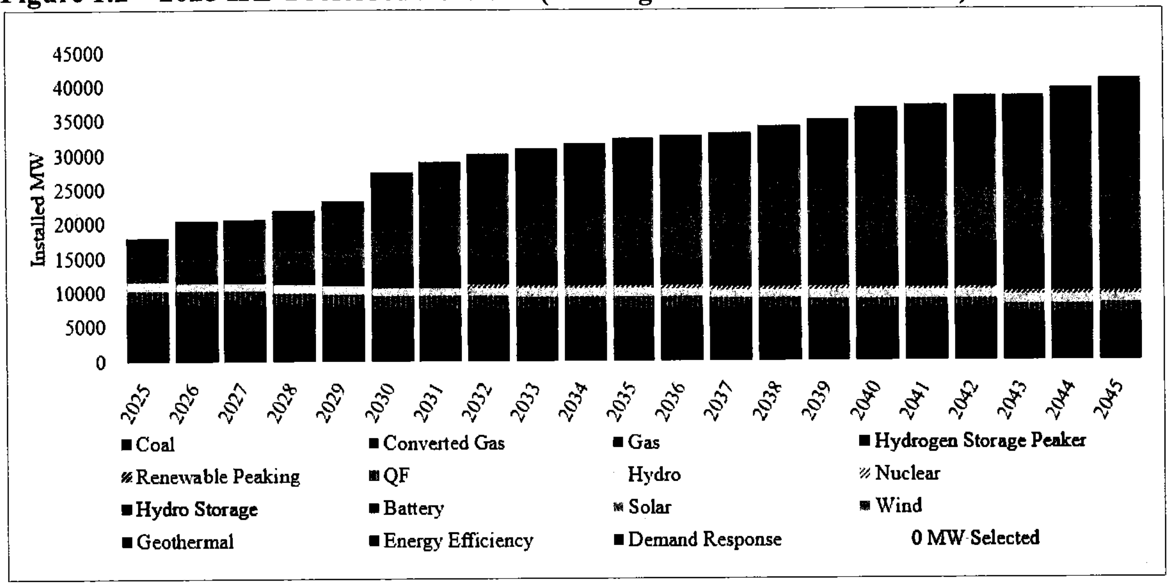
Preferred Portfolio Highlights

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.

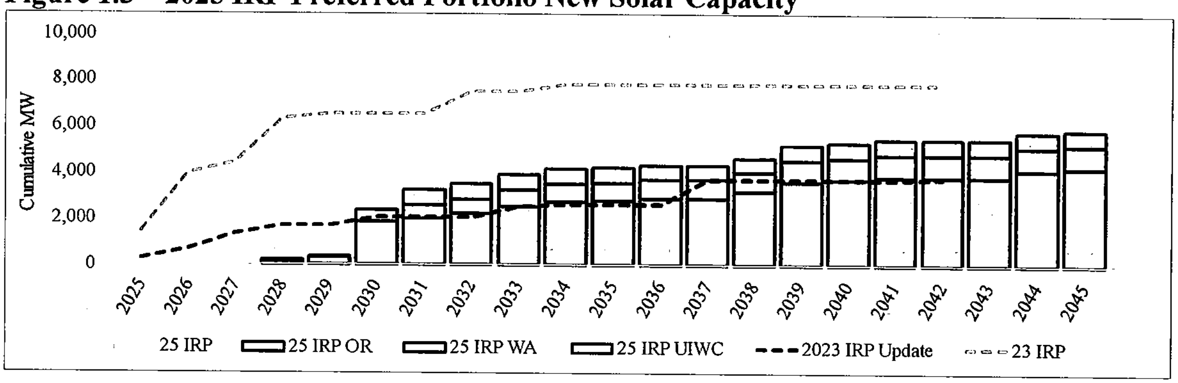
[2] Transmission upgrades frequently include primarily all-or-nothing components, though the cluster study process allows for some project-specific timing and costs.

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.

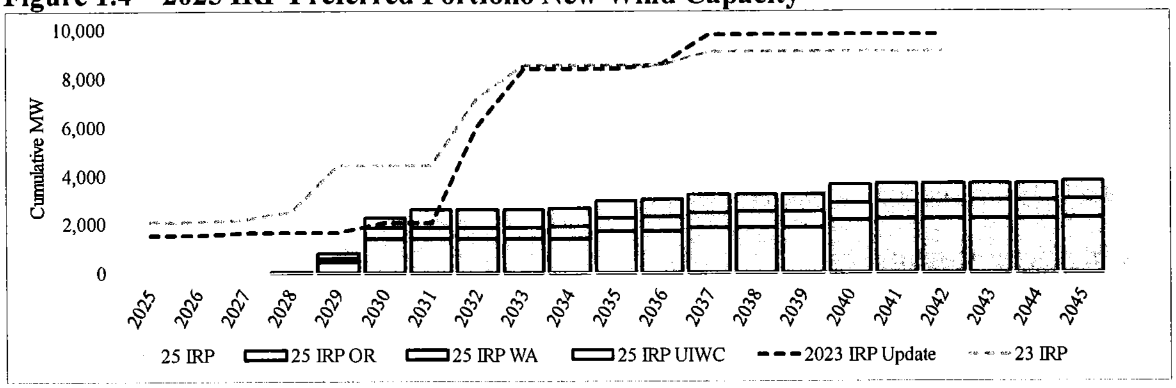
Figure 1.3 – 2025 IRP Preferred Portfolio New Solar Capacity



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.

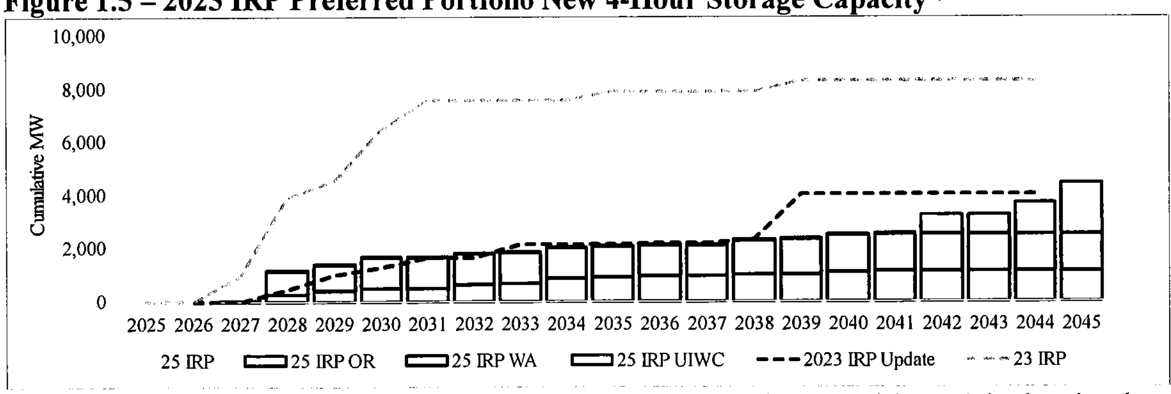
Figure 1.4 – 2025 IRP Preferred Portfolio New Wind Capacity



New Storage Resources

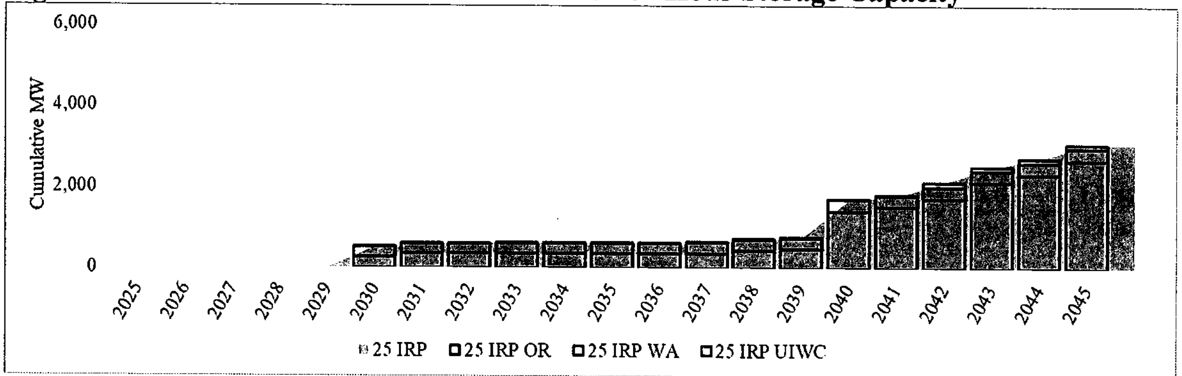
New storage resources in the 2025 IRP preferred portfolio are summarized in Figure 1.5 and Figure 1.6. The 2025 IRP preferred portfolio includes 1,684 MW of new 4-hour storage resources by the end of 2030, 2,072 MW by the end of 2035 and 4,451 MW by the end of 2045. Additionally, the 2025 IRP preferred 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]

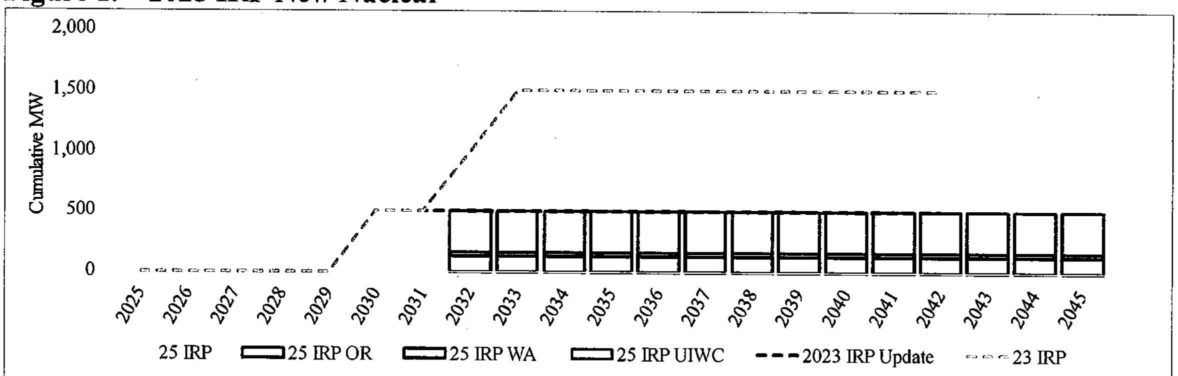


[1]The 2025 IRP preferred portfolio includes 41 MW of renewable peaking by the end of the planning horizon.

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

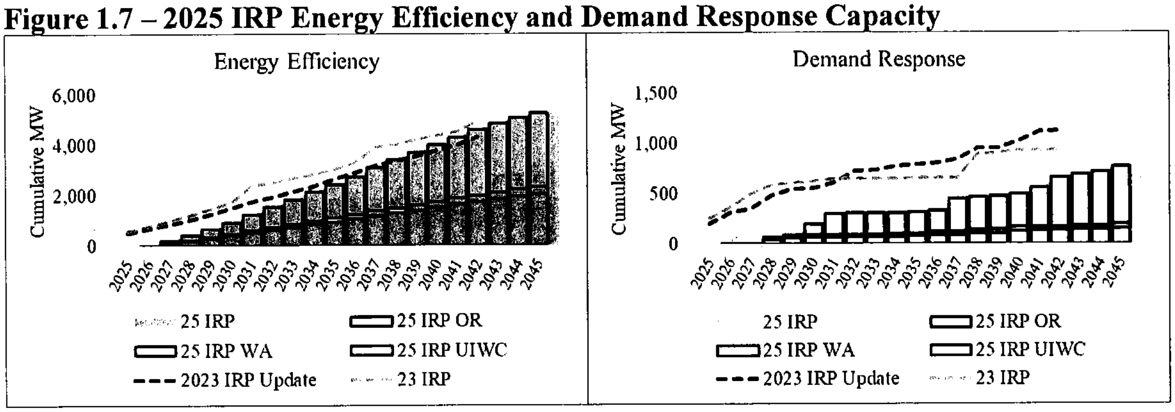
PacifiCorp evaluates new demand-side management (DSM) opportunities, which includes both energy efficiency and demand response programs, as a resource that competes with traditional new generation and wholesale power market purchases when developing resource portfolios for the IRP. The optimal determination 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

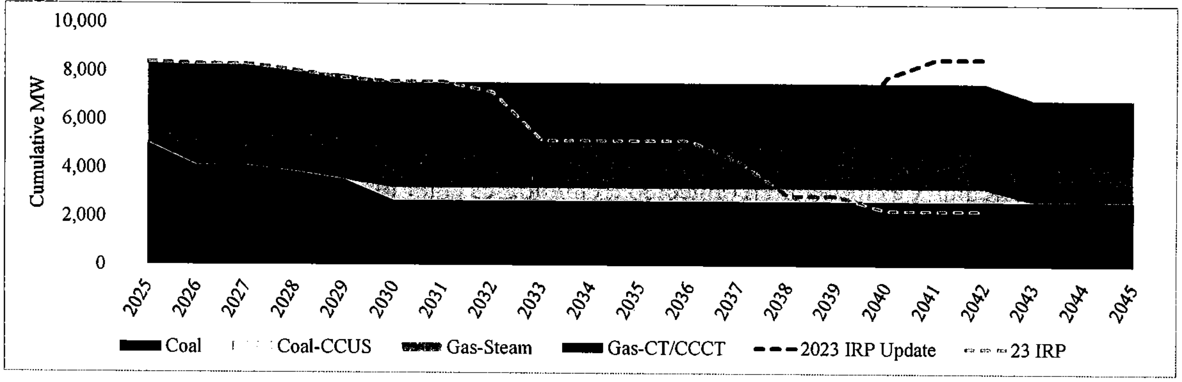


Coal and Gas Exits, Retirements, and Gas Conversions

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

[illegible]			
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

[illegible]		
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)

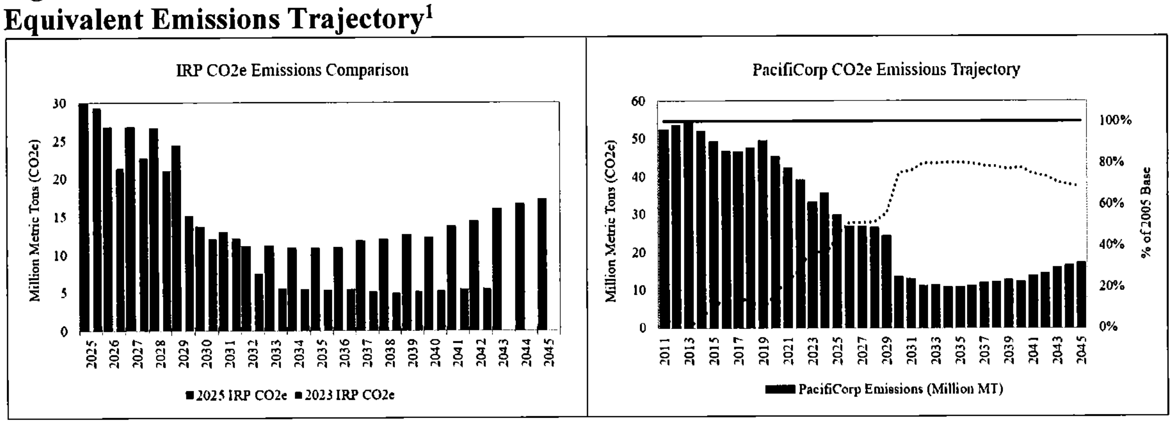
Carbon Dioxide Emissions

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.

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

	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	**<u>Natrium™ Demonstration Project:</u>** 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	**<u>Ozone Transport Rule Compliance:</u>** 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	**<u>Natural Gas Emissions Compliance Strategies</u>** 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	**<u>Federal Greenhouse Gas Emission Compliance:</u>** 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	**<u>Dave Johnston Units 1 and 2:</u>** 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.

	2. New Resource Actions
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 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	**<u>2025 All-Source Request for Proposals:</u>** 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.

[illegible]	4. Demand-Side Management (DSM) Actions
a	**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

[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 114° F in Sacramento, California, 110° F in Burbank, California, and 107° 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*

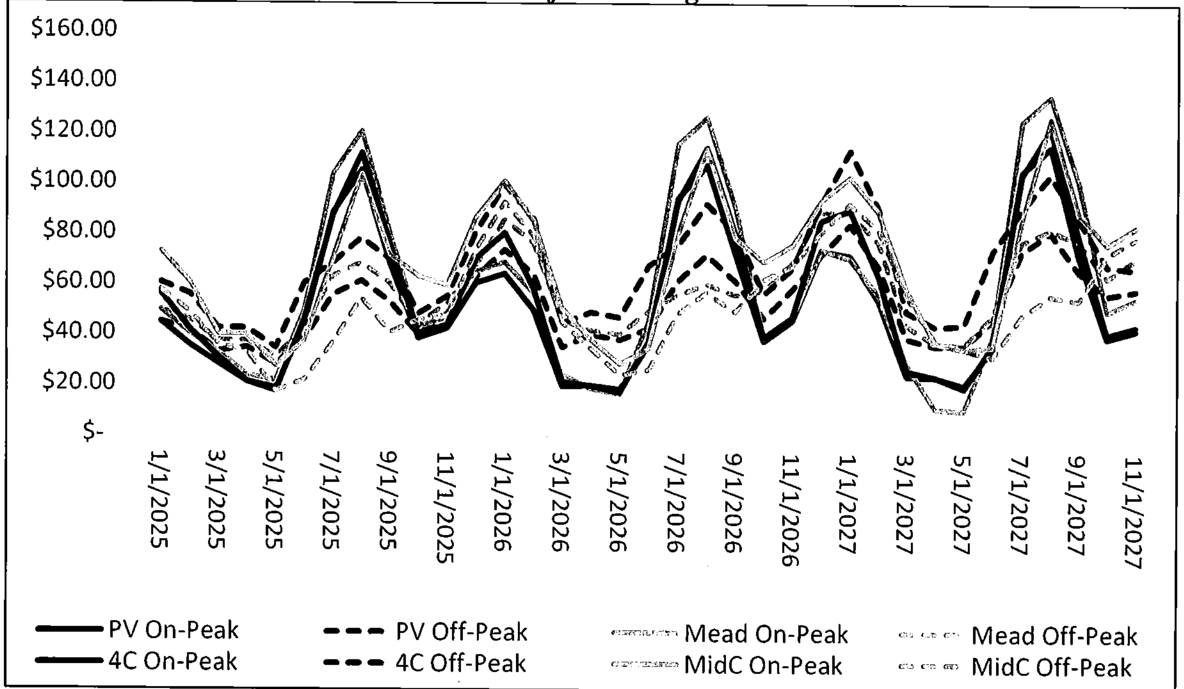
Source: SNL

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

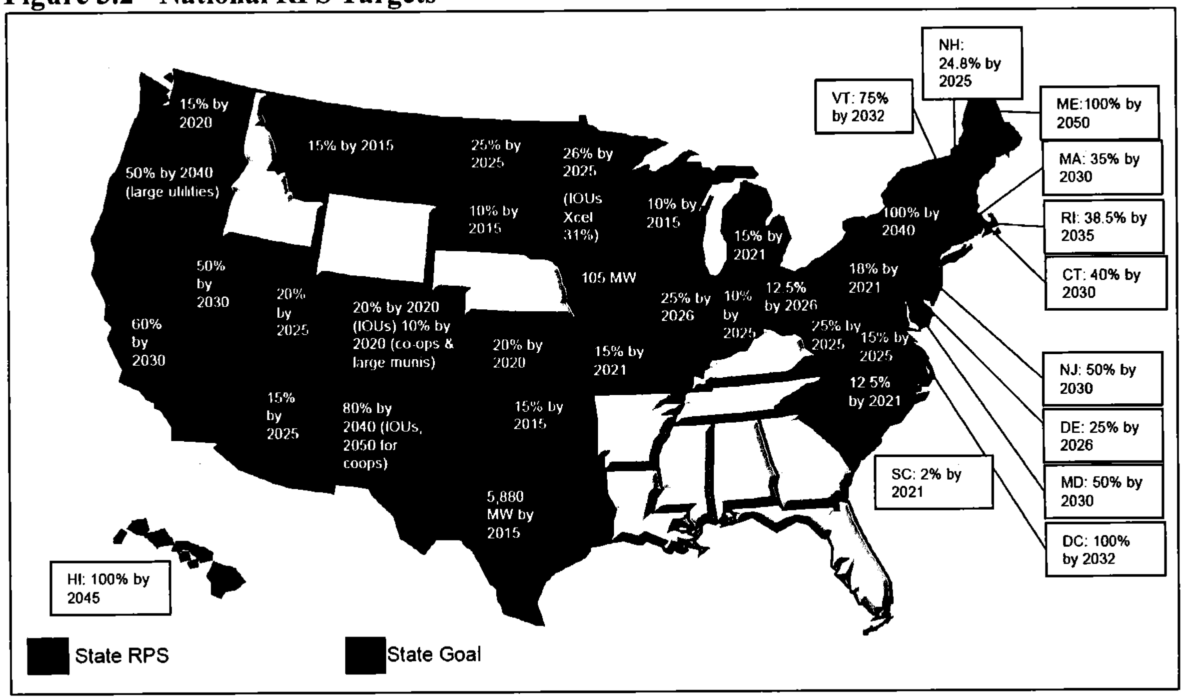
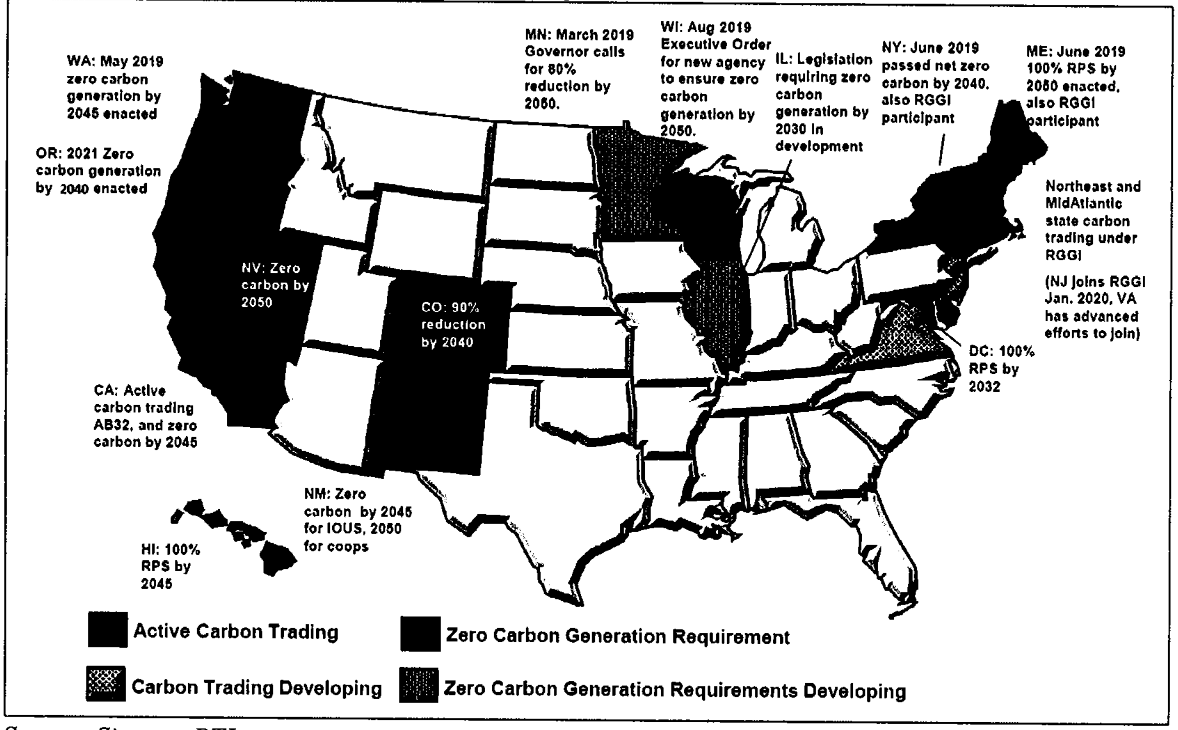
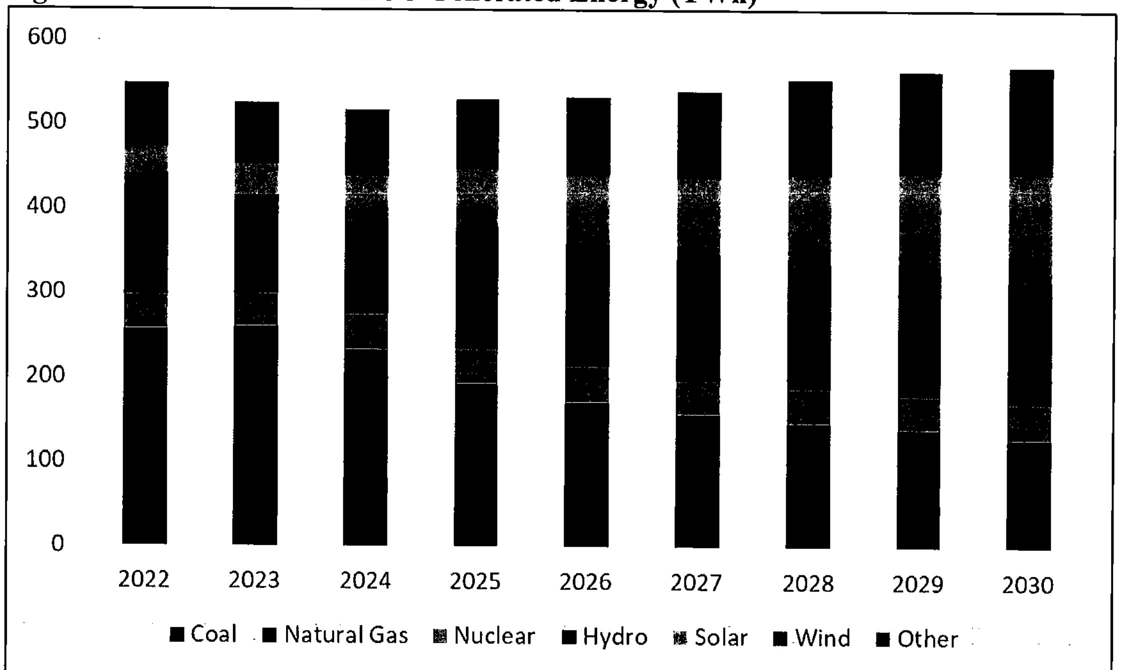


Figure 3.3 - States with CO_2 Reduction Targets



Source: Siemens PTI

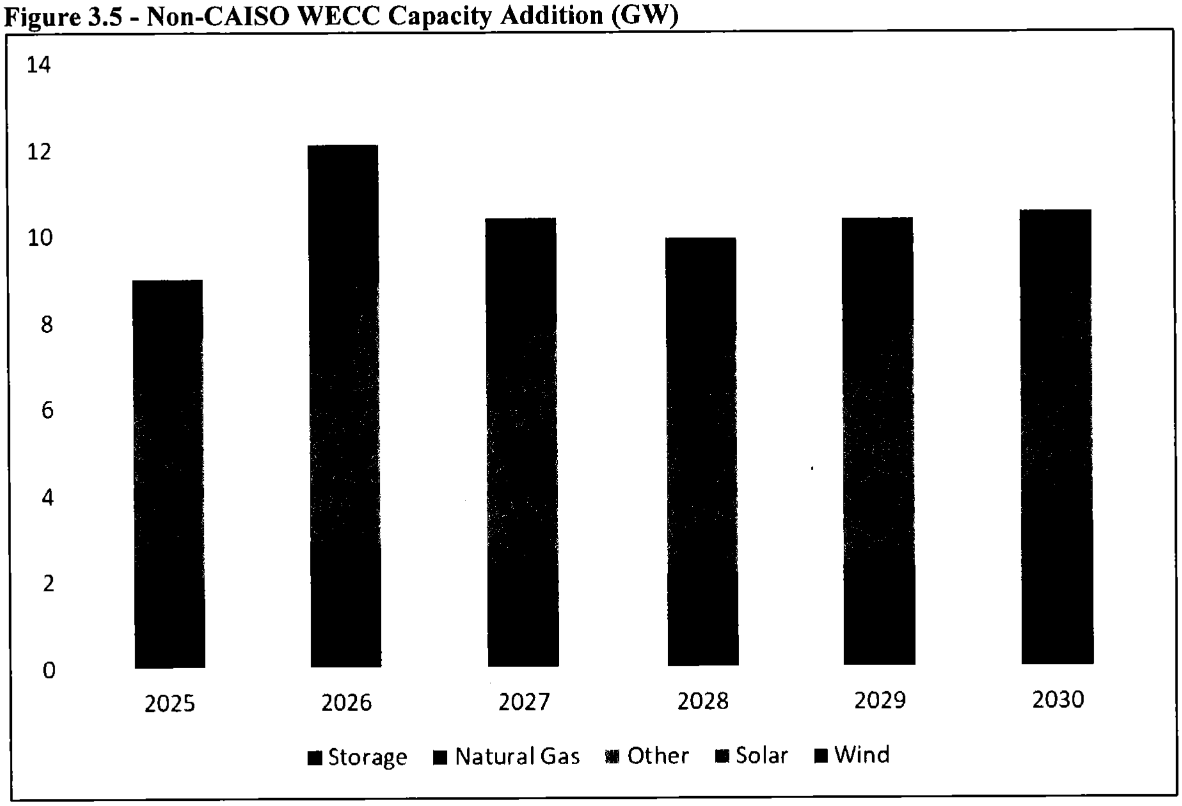
Figure 3.4 - Non-CAISO WECC Generated Energy (TWh)



Source: IHS Markit, SNL, Siemens PTI

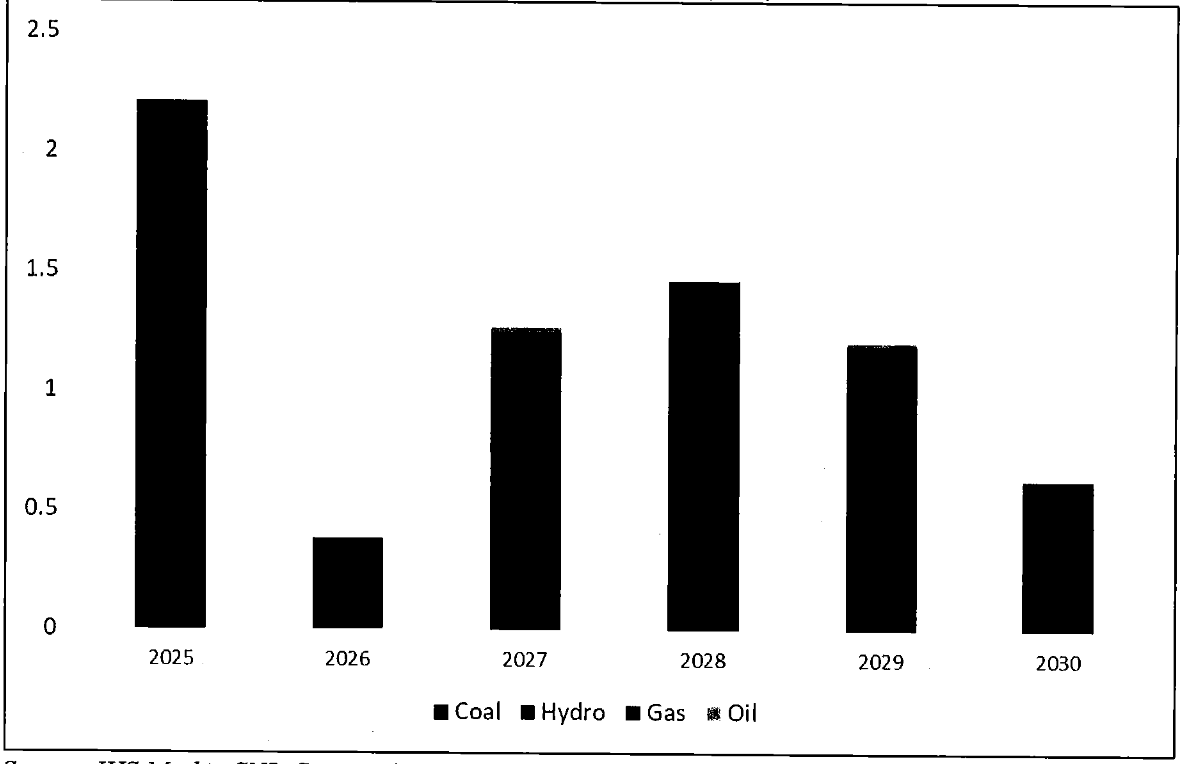
In 2023, 3.5 GW of solar resources and 600 MW of wind were added in the non-CAISO WECC, with similar quantities coming online through October 2024. Into 2025, Siemens expects approximately 3.6 GW of wind and 2.1 GW of solar to come online based on activity in regional interconnection queues. Storage 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

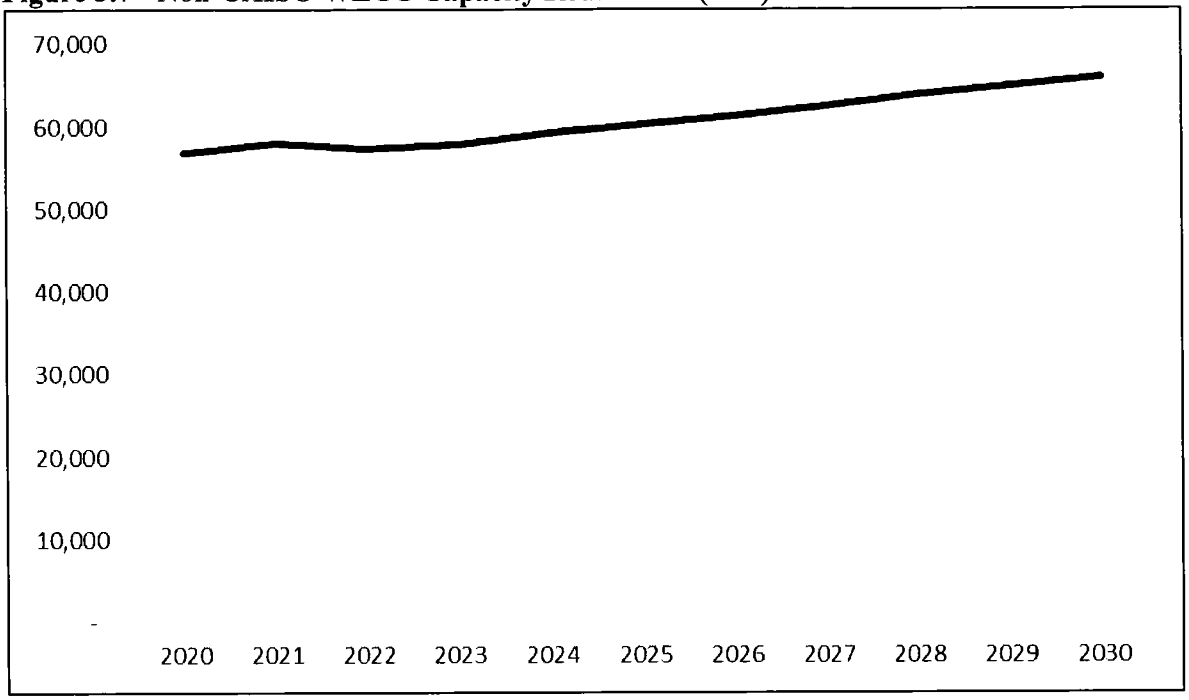
Emissions and Environment

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.

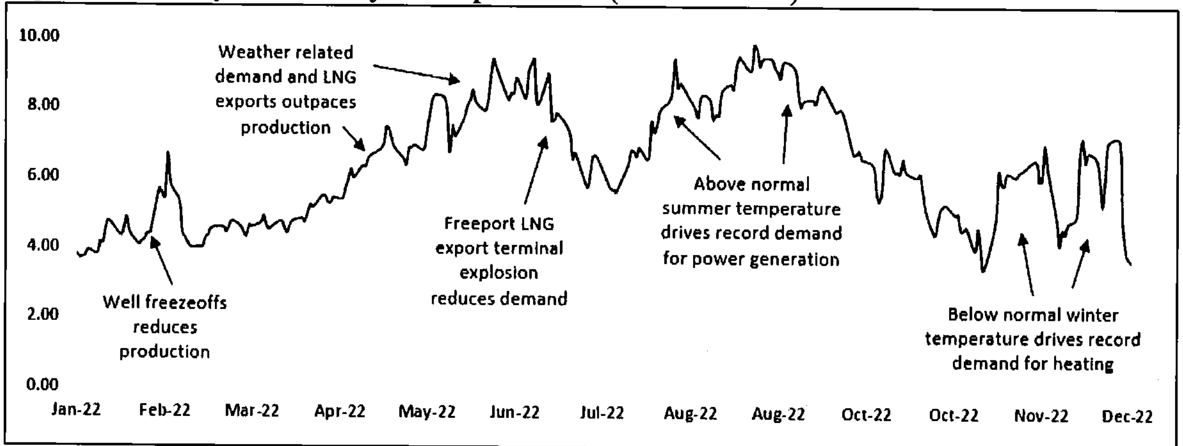
Natural Gas Prices

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.

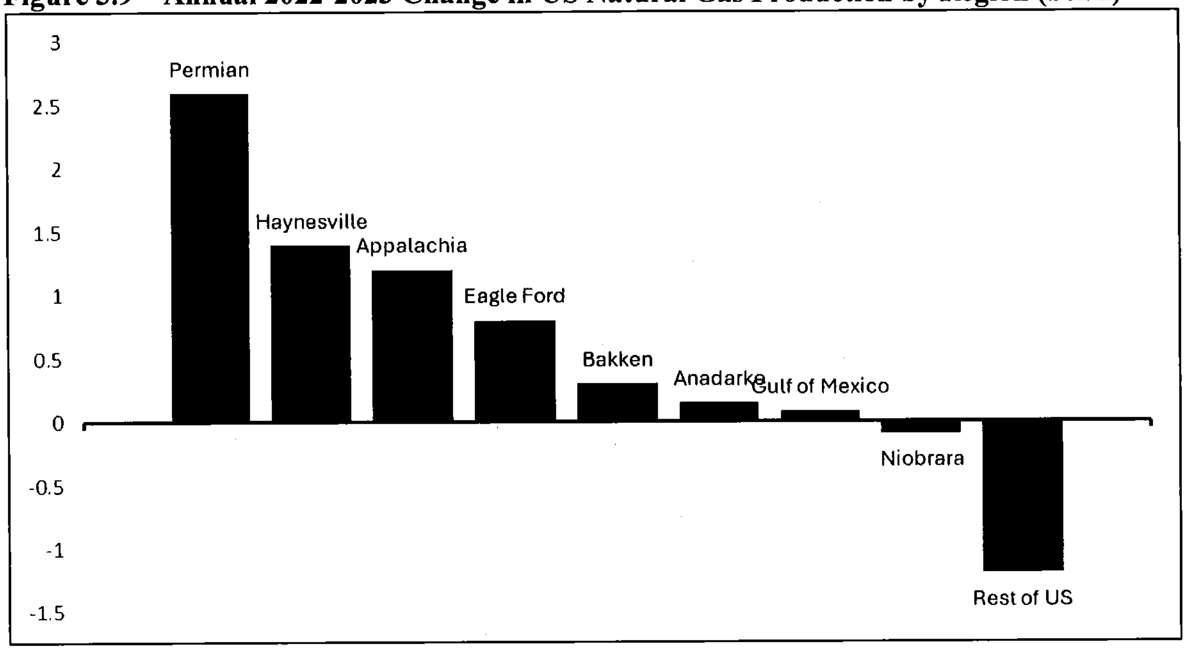
Production growth slowed over the second half of 2022 as inflation, labor, and materials shortages, and service sector constraints continued to impact producers, keeping overall domestic production hovering around 100 Bcf/d. Natural gas delivery in the US is complex due to the number of supply sources 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.

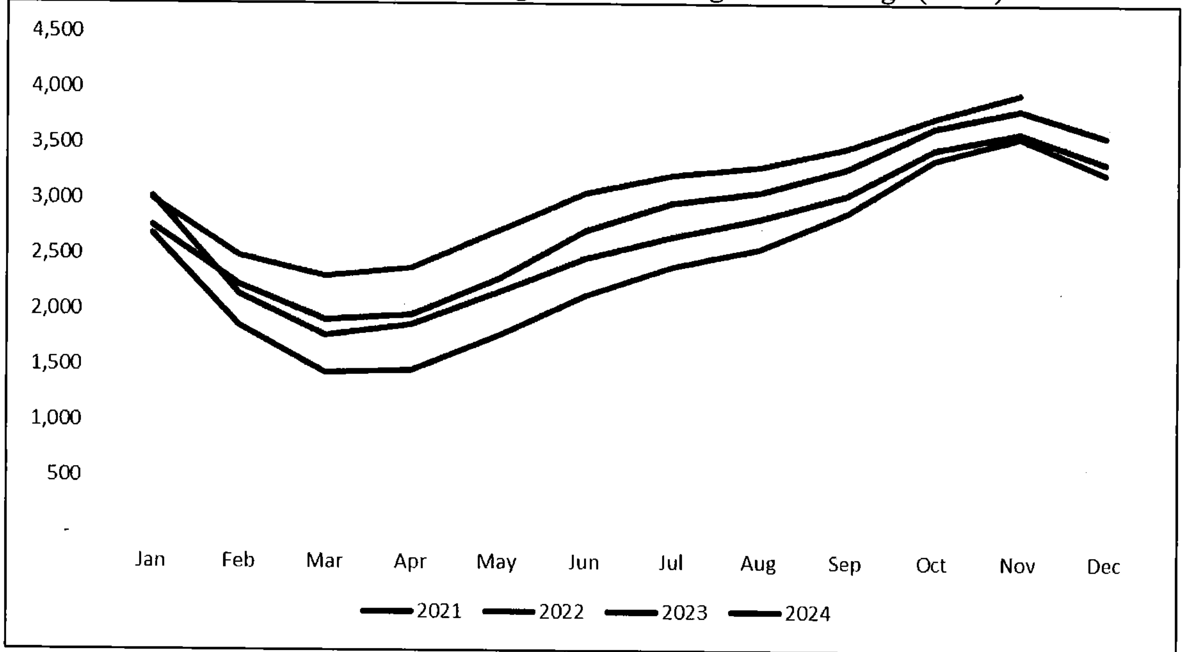
Figure 3.9 – Annual 2022-2023 Change in US Natural Gas Production by Region (bcf/d)



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

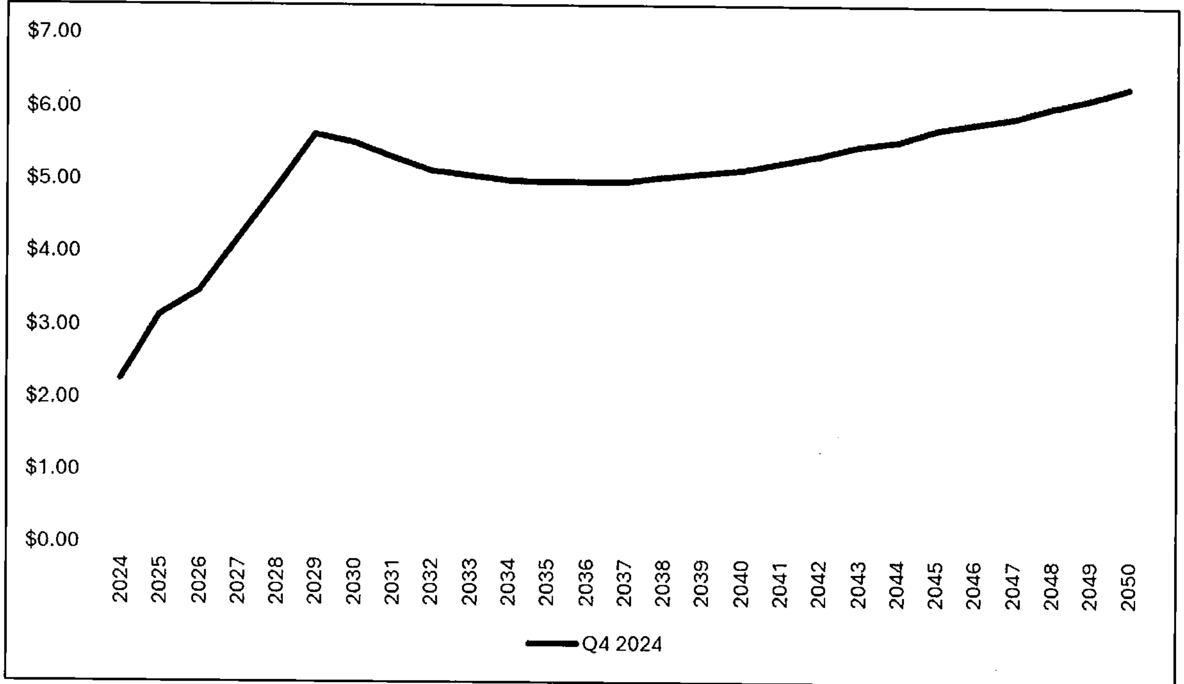
On the demand side, residential and commercial consumption increased due to a colder winter compared to 2023, reversing the trend of reduced heating needs observed in the prior year. LNG exports reached a record 12.1 Bcf/d as global demand for U.S. natural gas grew, particularly in Europe, where efforts 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.

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 determinedto 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 NOx 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 NOx 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 NOx 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 NOx 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 statethat 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 ofthese.

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 ofRECs.

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

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.

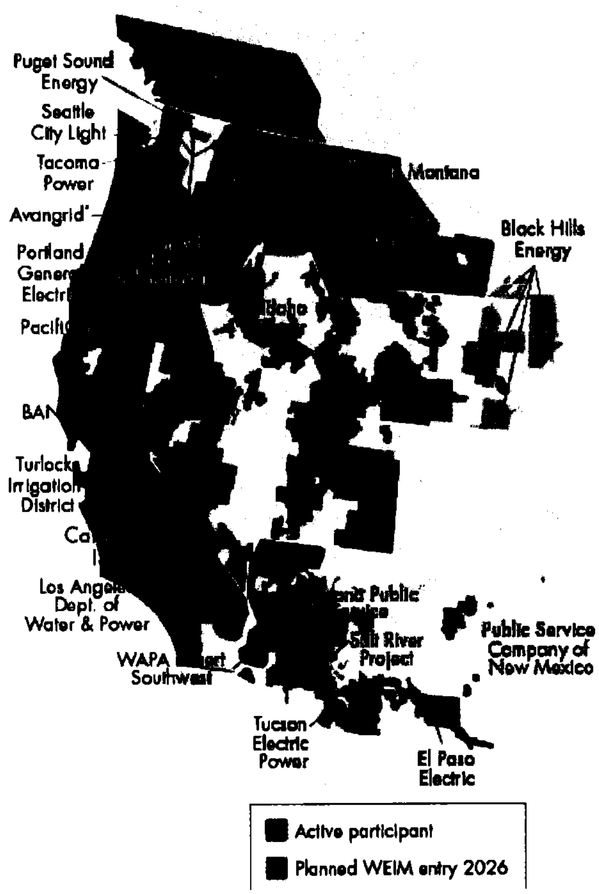
Electricity Market Development Update

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.

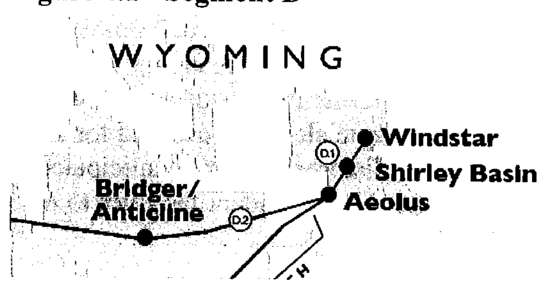
Aeolus to Mona/Clover (Gateway South – Segment F)

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



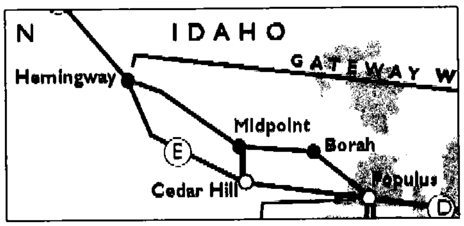
- D1—Recently placed in service, a single-circuit 230-kV line running approximately 59 miles between the existing Windstar and Aeolus substations while looping in and out of Shirley Basin substation in eastern Wyoming.
- D2—A single-circuit 500-kV line completed October 2020 and energized November 2020.
- 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.

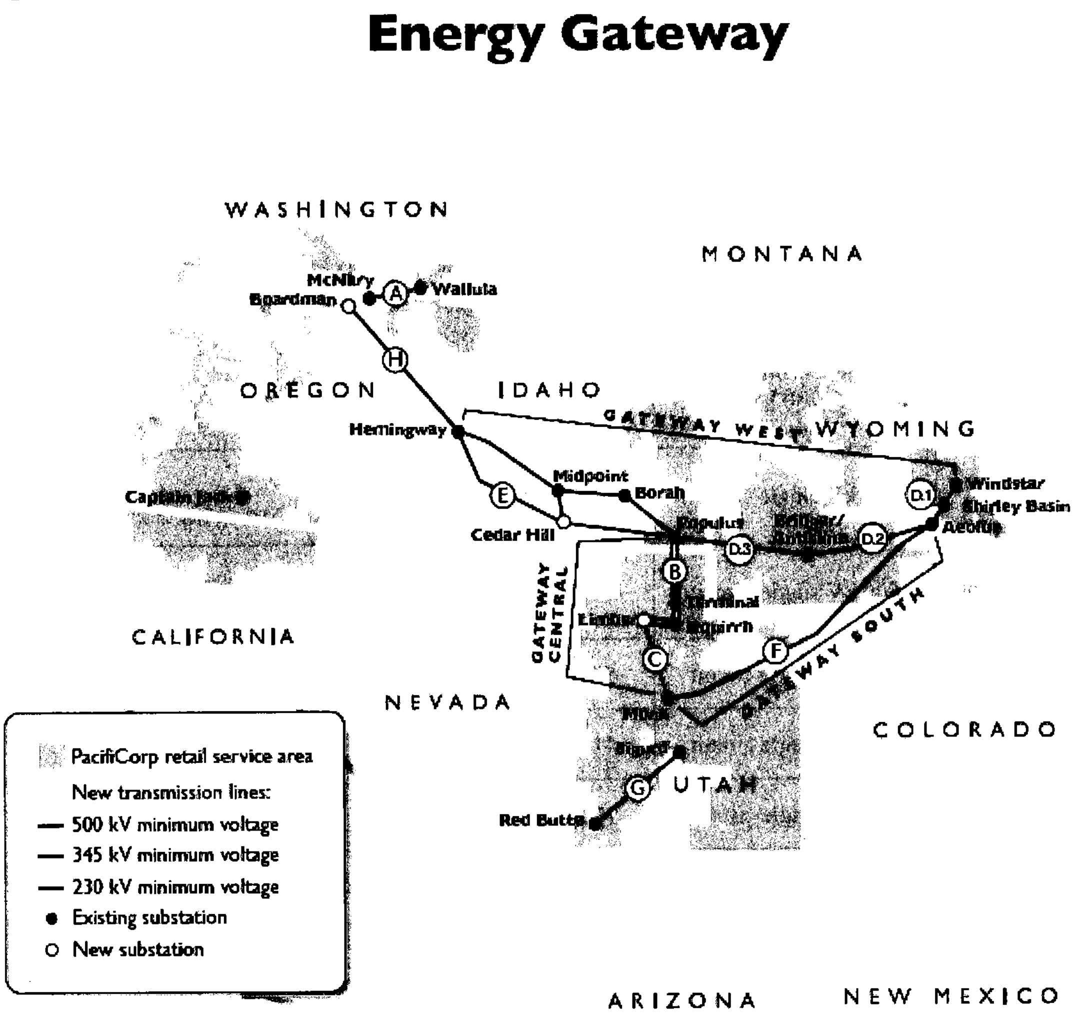
In October 2020, a portion of Gateway West Segment D1, the 230 kV line between Aeolus and Shirley Basin was also constructed and completed in 2020. The remaining portion of Gateway West, Segment D1, consisting of a new 230 kV line between Shirley Basin and Windstar substations and a rebuild of an existing 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%	[redacted]	[redacted]	[redacted]	[redacted]
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%	[redacted]	[redacted]	[redacted]	[redacted]
Prospective Reserve Margin (%)	38.6%	40.1%	38.2%	31.1%	26.7%	20.4%	16.8%	[redacted]	[redacted]	[redacted]
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%	[redacted]
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

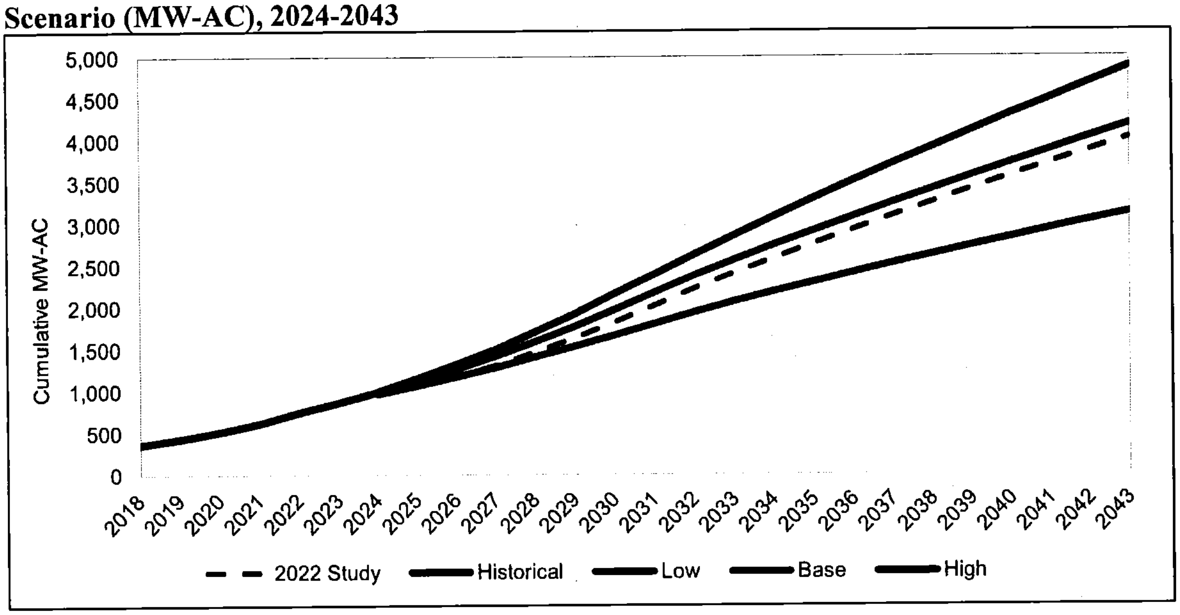
For the 2025 IRP, PacifiCorp contracted with DNV to update the assessment of distributed generation (DG)[2] penetration with new market, policy, and incentive developments.[3,4] The study provided a forecast of adoption of non-utility owned, behind-the-meter (BTM) customer generation resources in each 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.

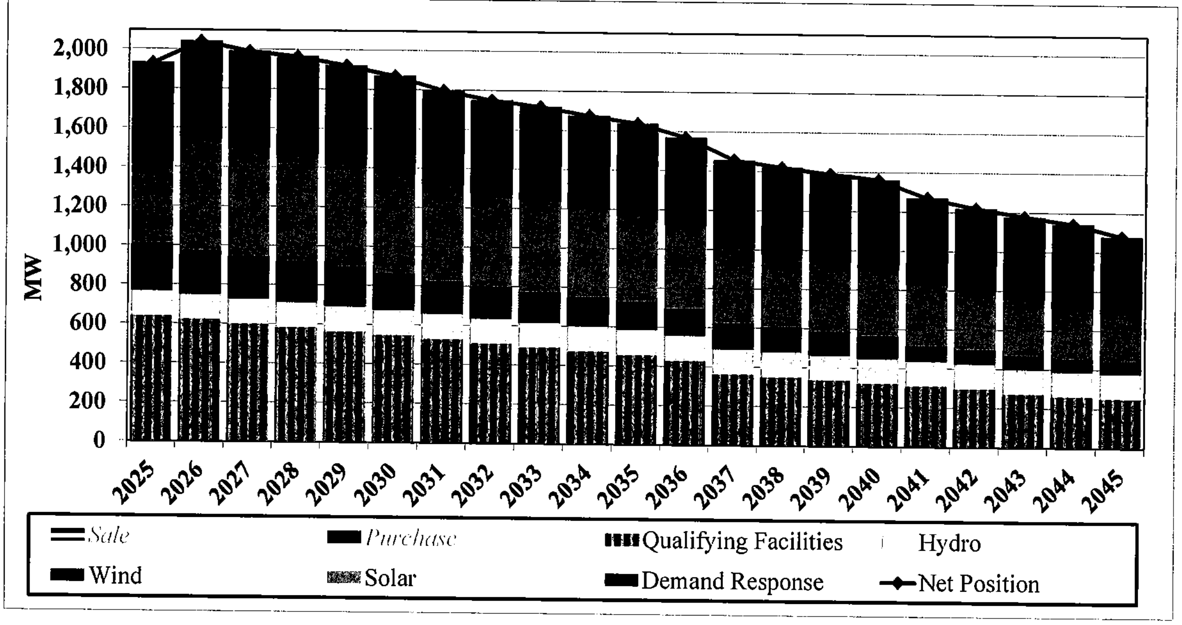
Figure 6.1 – Cumulative Historical and New Capacity Installed by Scenario (MW-AC), 2024-2043



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:

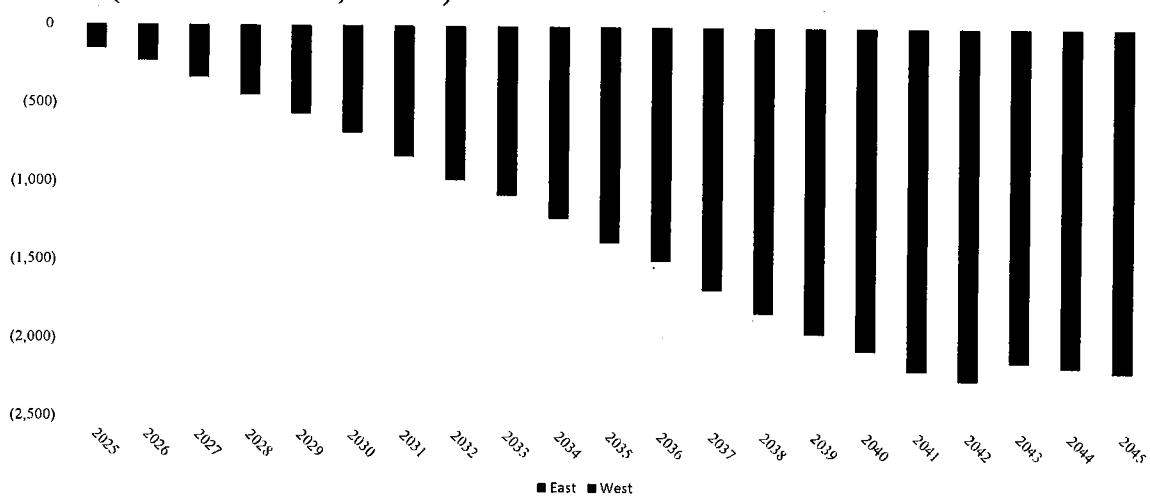
Load Net of Distributed generation

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

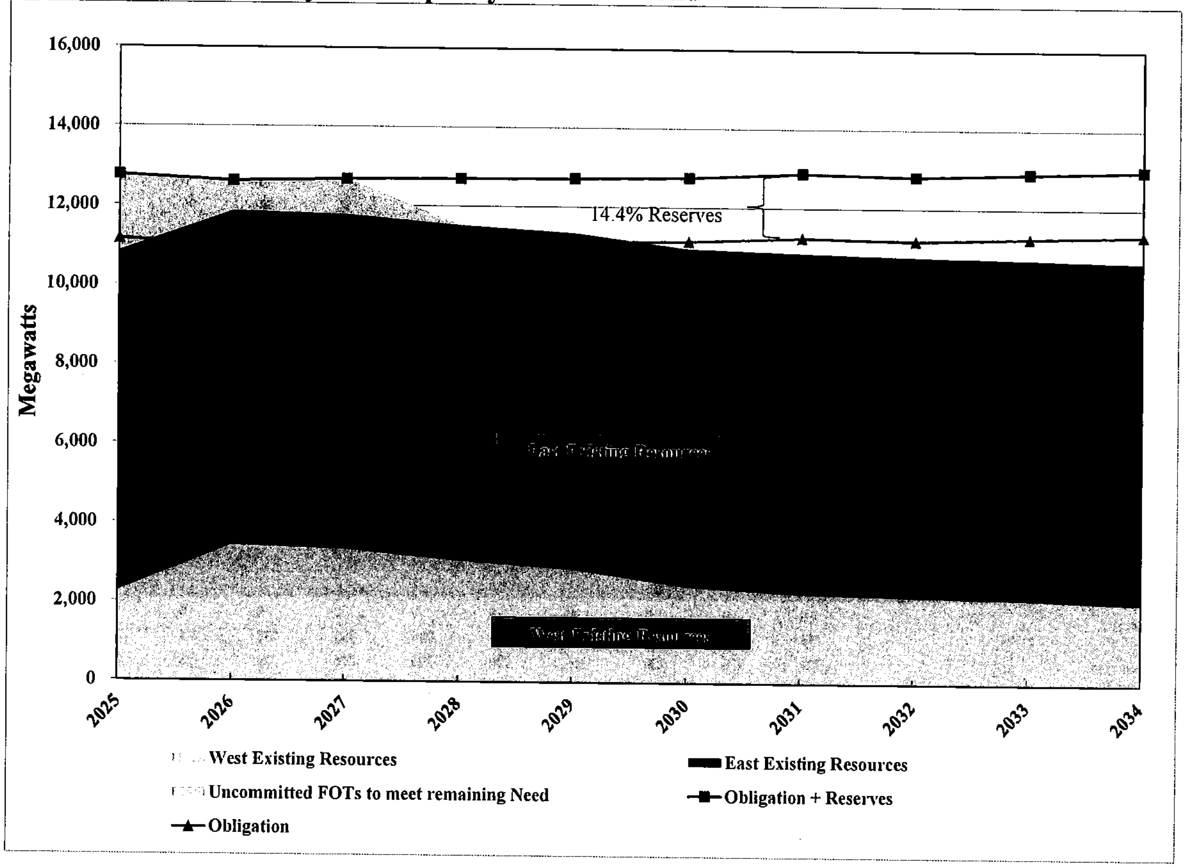


Figure 6.5 – Winter System Capacity Position Trend

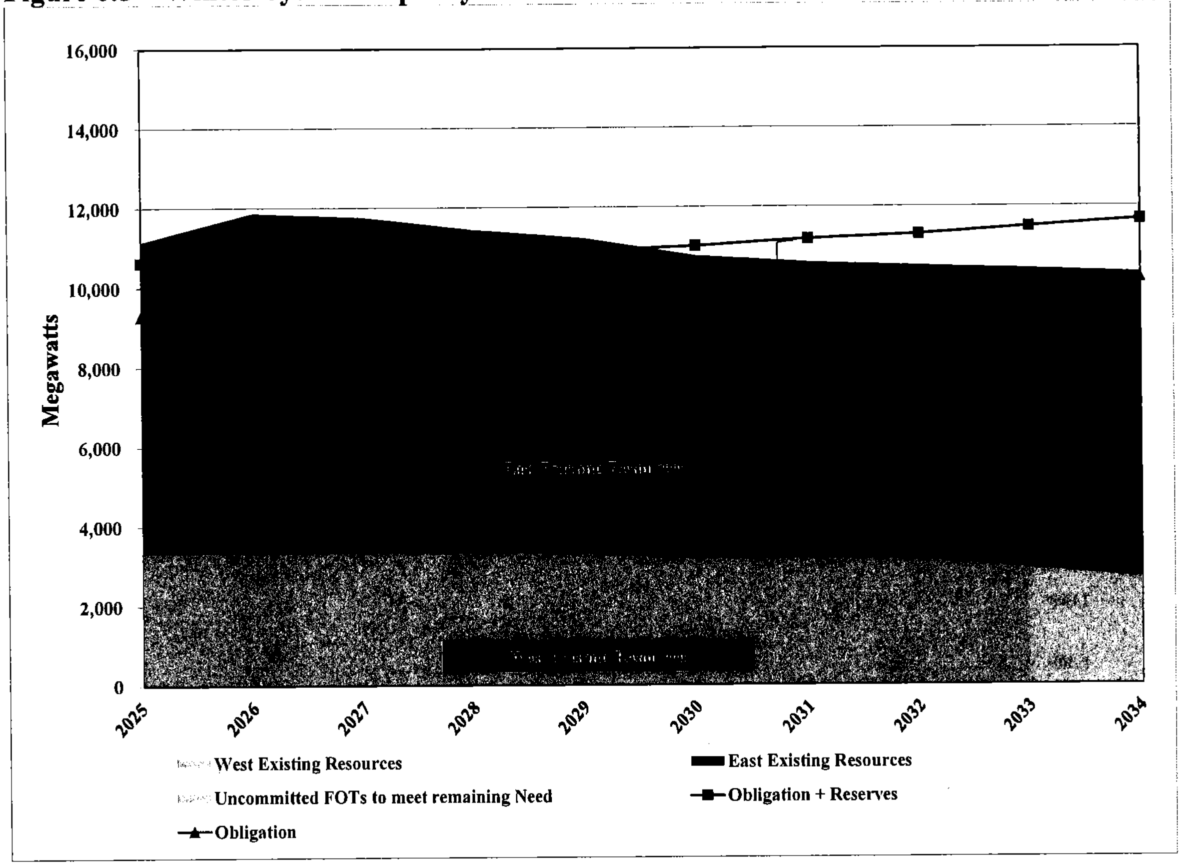


Figure 6.6 – East Summer Capacity Position Trend

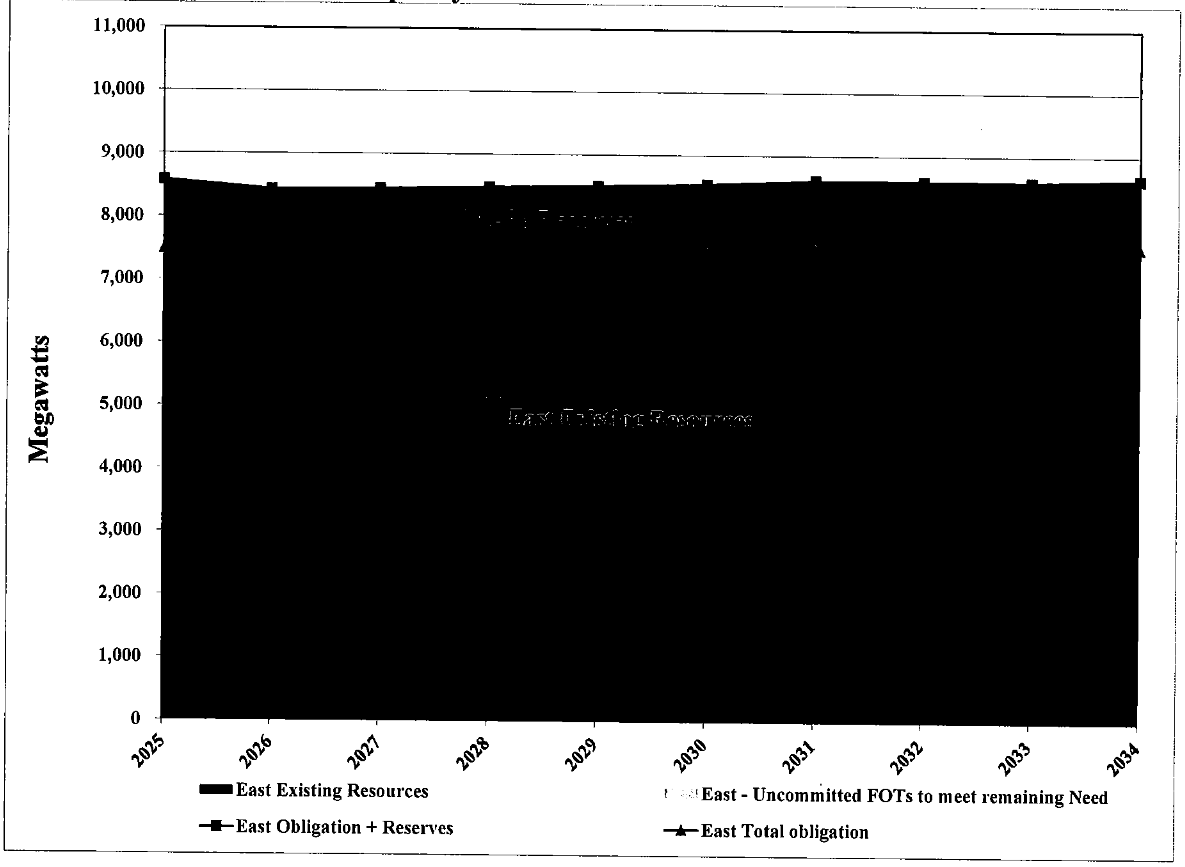
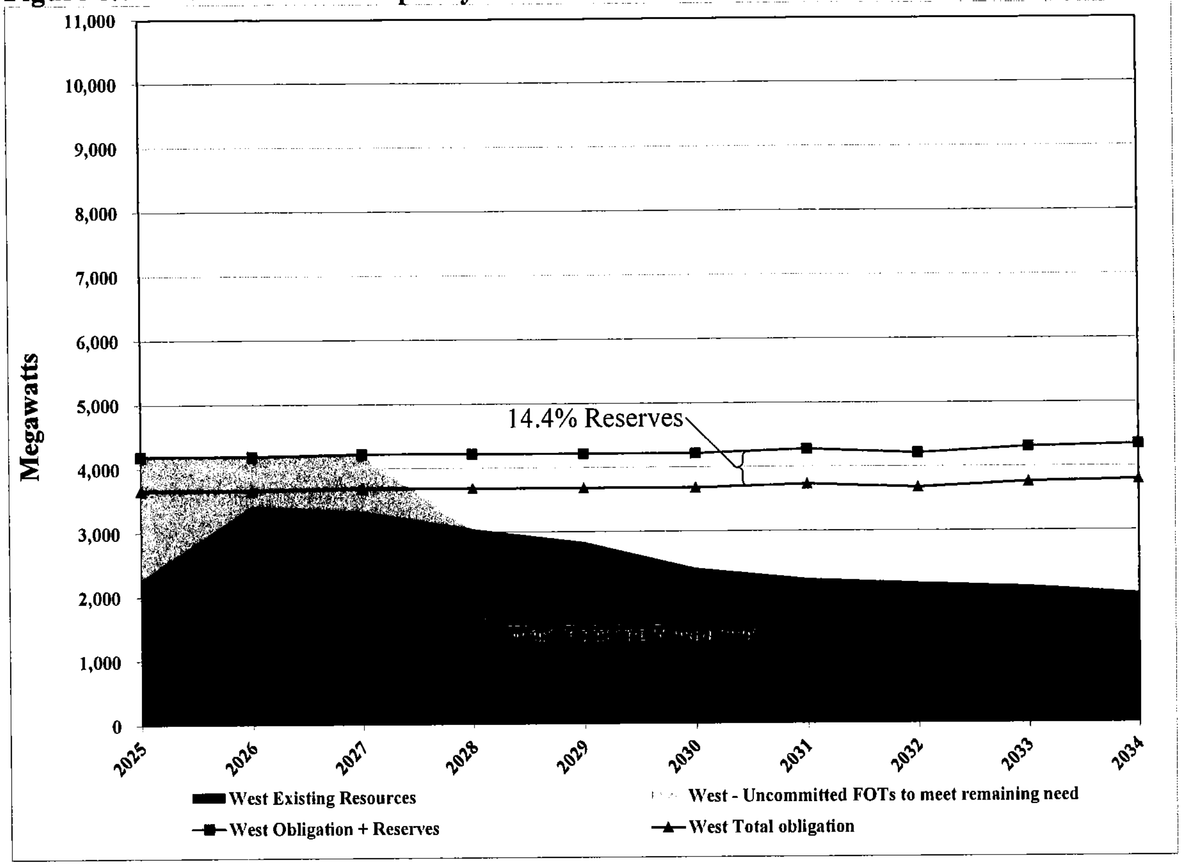


Figure 6.7 – West Summer Capacity Position Trend



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$)

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	Design Life (yrs)	Base Capital ($/kW)	Var O&M ($/MWh)	Fraction Var O&M Capitalized	Fraction Var O&M Affected by Capacity Changes	Fixed O&M ($/kW-yr)	Fraction Fixed O&M Capitalized	Dismantling Cost ($/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$)

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$)

Fuel	Resource Description	Operating Characteristics				Environmental Data				
		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$)

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 Enhanced 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 in IRP	Elevation (AFSL)	Total Capital Cost	Decommissioning 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	$ 1,577.45	$ 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$)

Li-Ion, 4-hour, 20 MW[1]	No	NA	$ 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	NA	$ 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	NA	$ 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	$69.76	$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	NA	$ 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	NA	$ 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	NA	$ 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	NA	$ 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	NA	$ 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	NA	$ 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	NA	$ 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	NA	$ 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	NA	$ 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	NA	$ 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	NA	$ 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 ($/MWh)	Total Resource Cost with PTC/ITC Credits ($/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 Enhanced 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$)

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
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$)

	Variable O&M	Credits	
Resource Description	O&M ($/MWh)	Tax Credits ($/kW-yr) (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 NOx. Included are SCR units for further reduction of NOx 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 NOx."[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

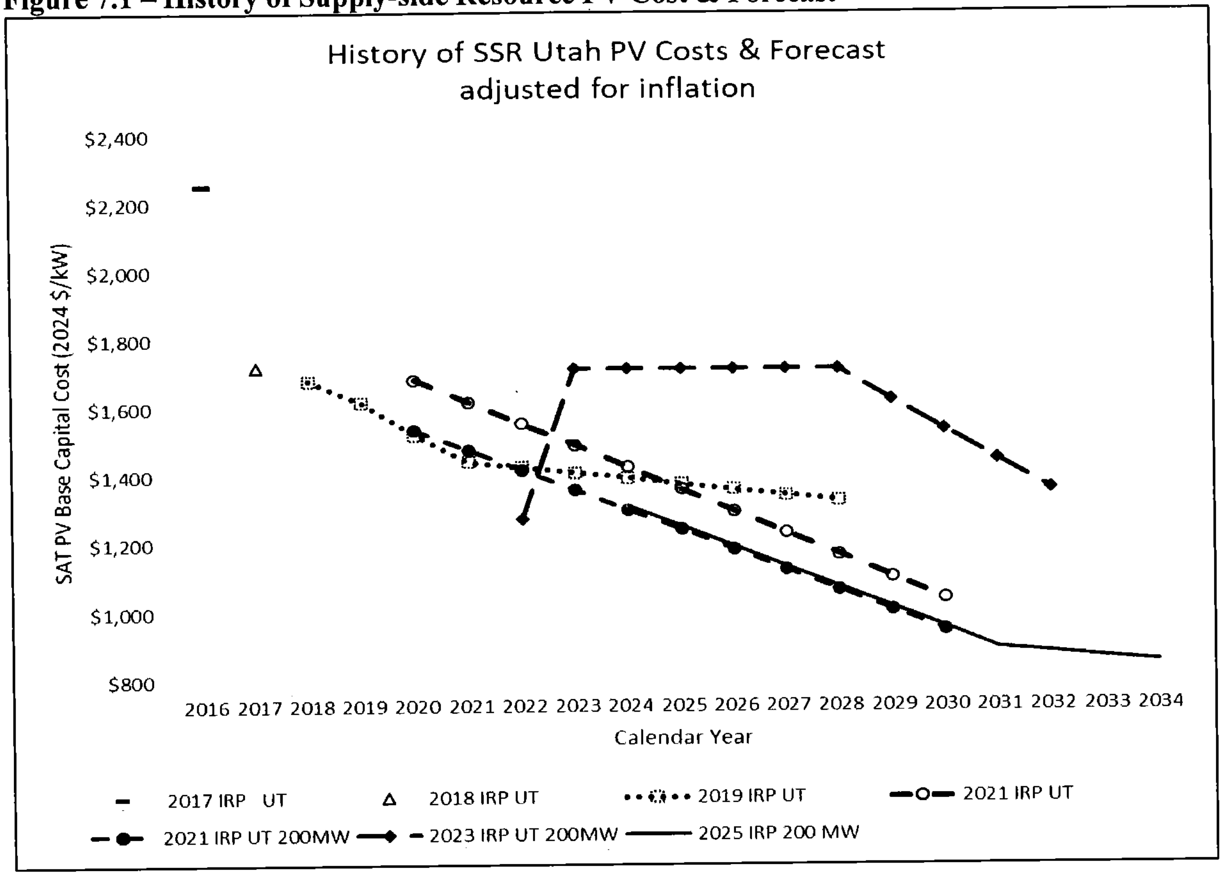
Appendix A of the EIA reports contain cost modifiers for selected cities within each state, and Appendix B of the EIA reports contains locational modifiers for combustion turbines that are largely dependent on altitude and ambient temperatures. The ATB contains cost forecasts for most resource options 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).

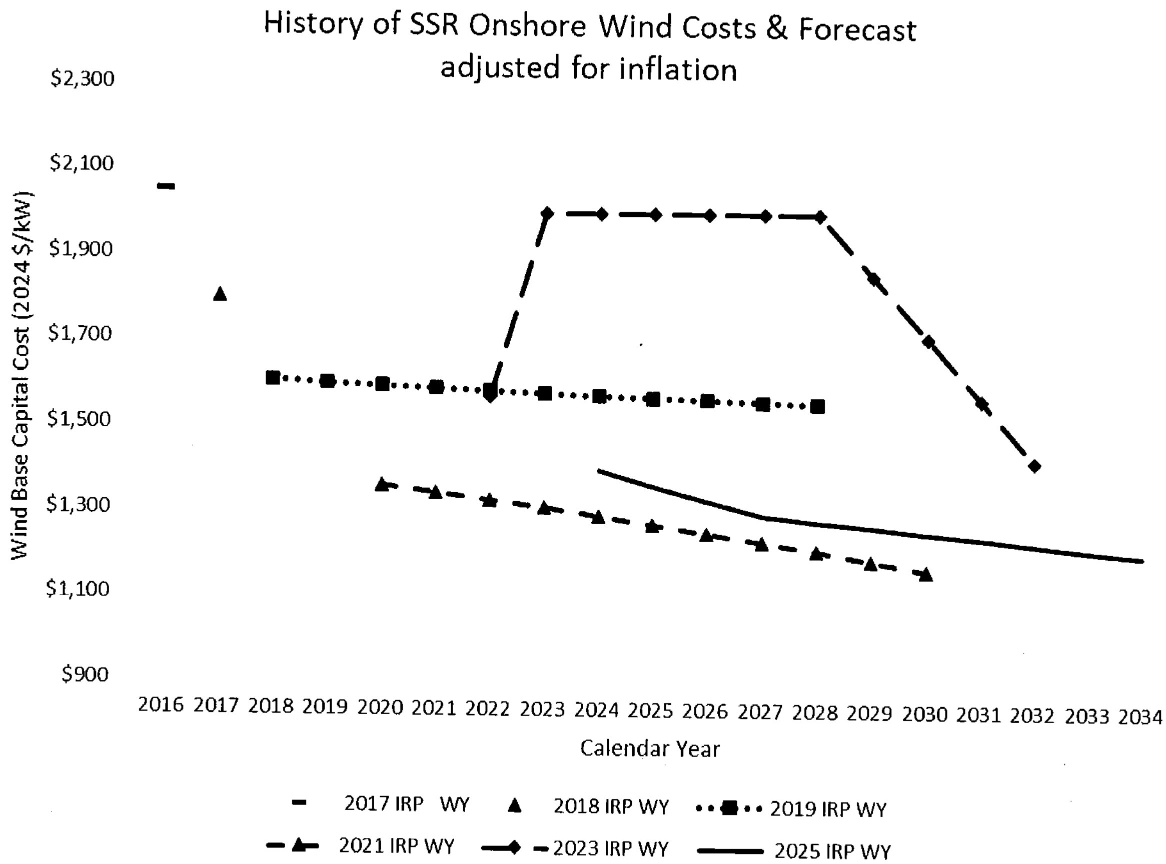
Figure 7.1 – History of Supply-side Resource PV Cost & Forecast



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.

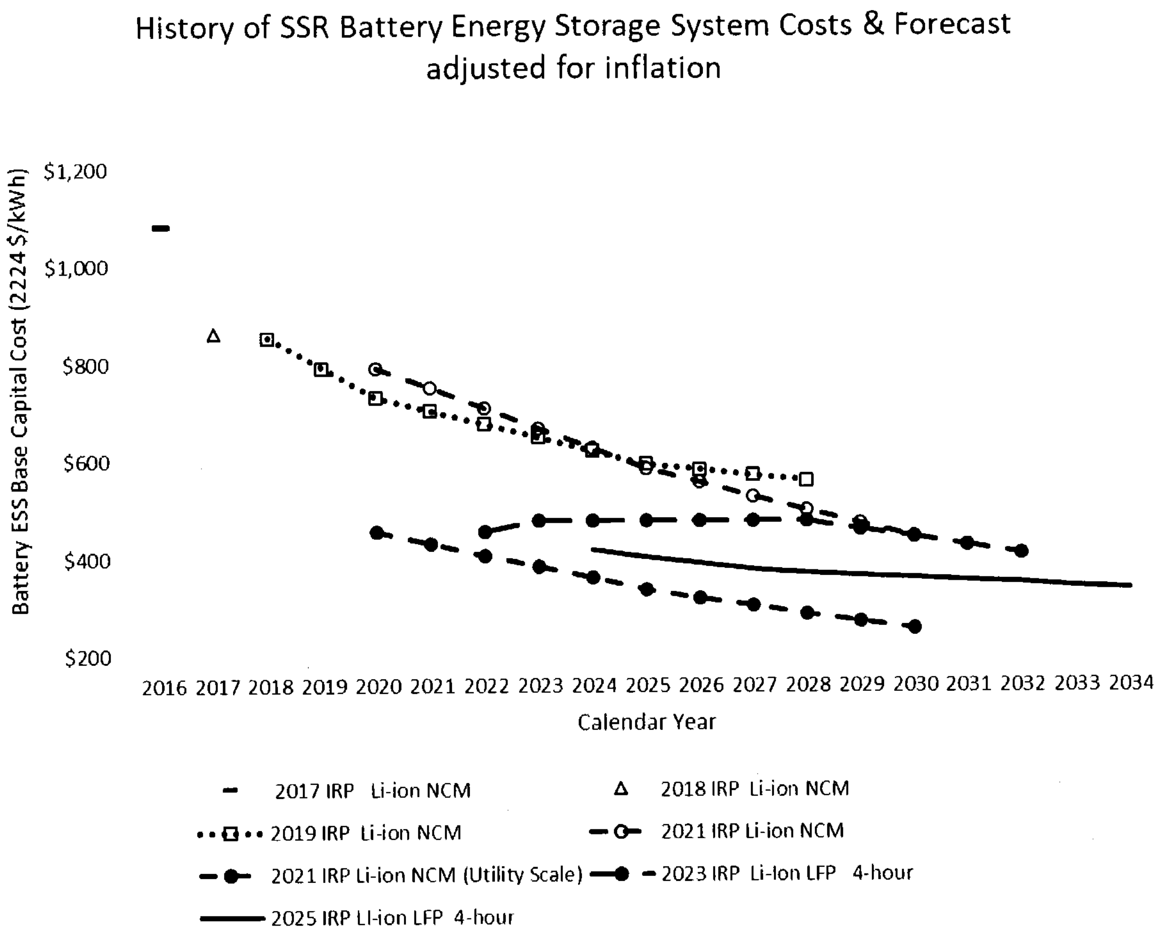
Figure 7.2 – History of Supply-side Resource Wind Costs & Forecast



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]*

	Summer		Winter	
Product	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 20-Year Potential (MW)	Summer Levelized Cost ($/kW-yr)	Winter 20-Year Potential (MW)	Winter Levelized Cost ($/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.

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.

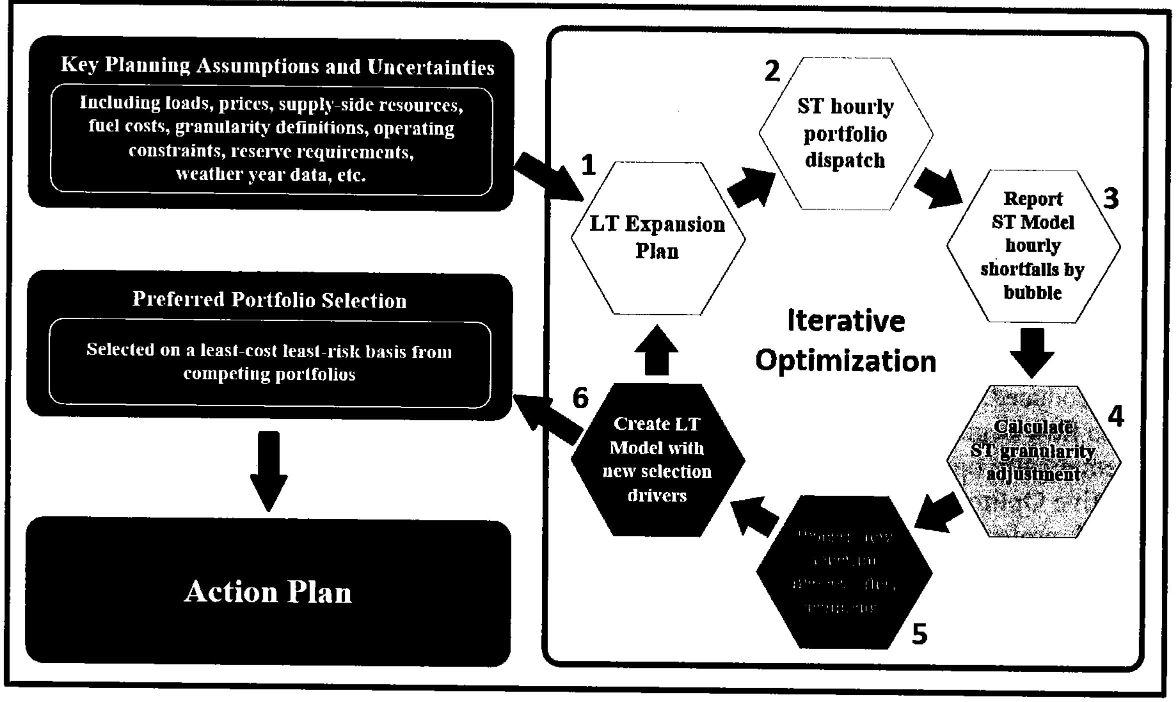
- A new price-policy variation ("MR", medium gas price with at-risk federal regulation) has been added to account for changing expectations for future federal policy.
- No market purchases are allowed in peak hours on the five days with the highest peak load in each month, market purchases are allowed 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.

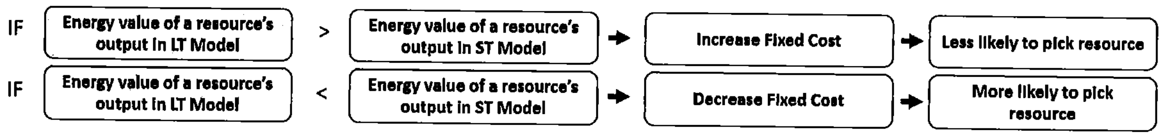
The 4 blocks used by the LT model include the top ten percent highest net load hours (load net of wind and solar generation), the highest wind generating hours, the highest solar generating hours, and the remainder of the hours. While these blocks are intended to help the LT model differentiate between 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 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.

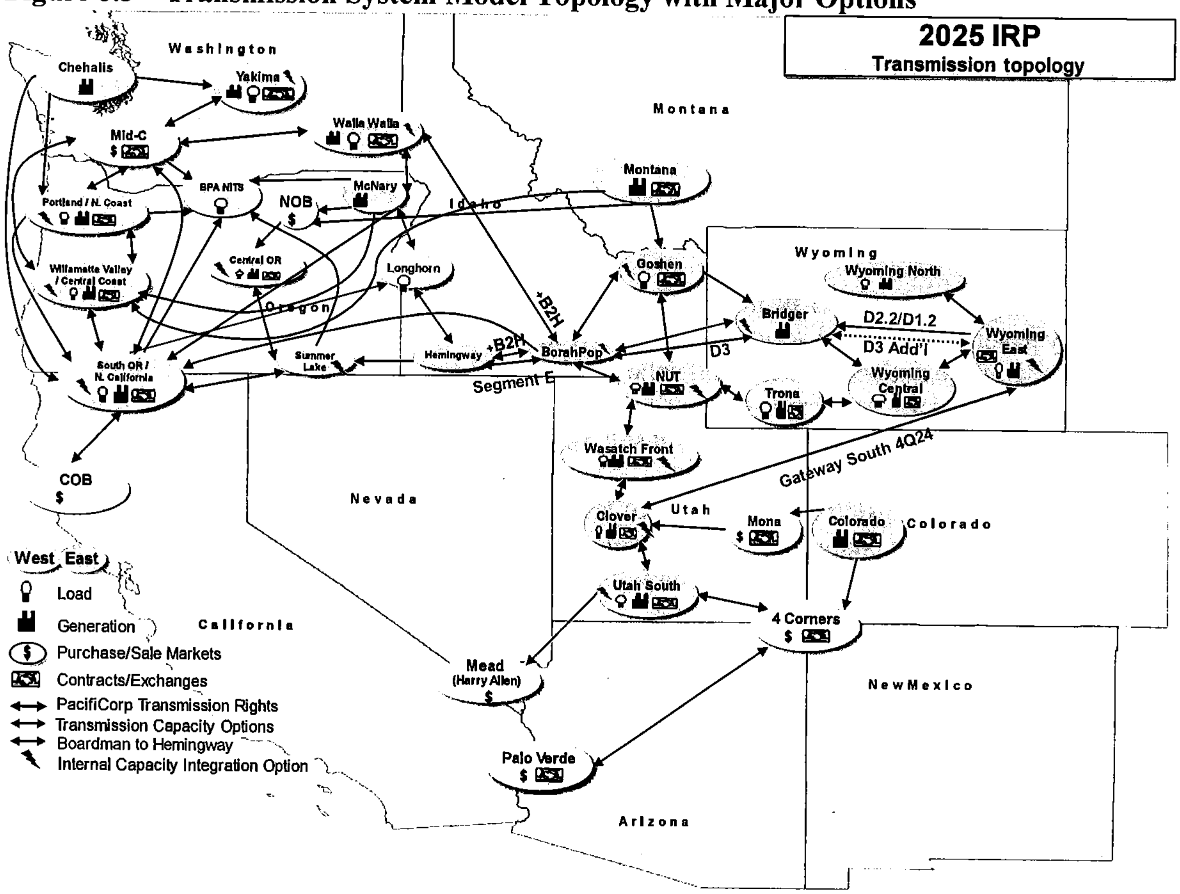
Key modeling elements and inputs for the LT capacity expansion model include the following:

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.

<u>Surplus Interconnections</u>
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

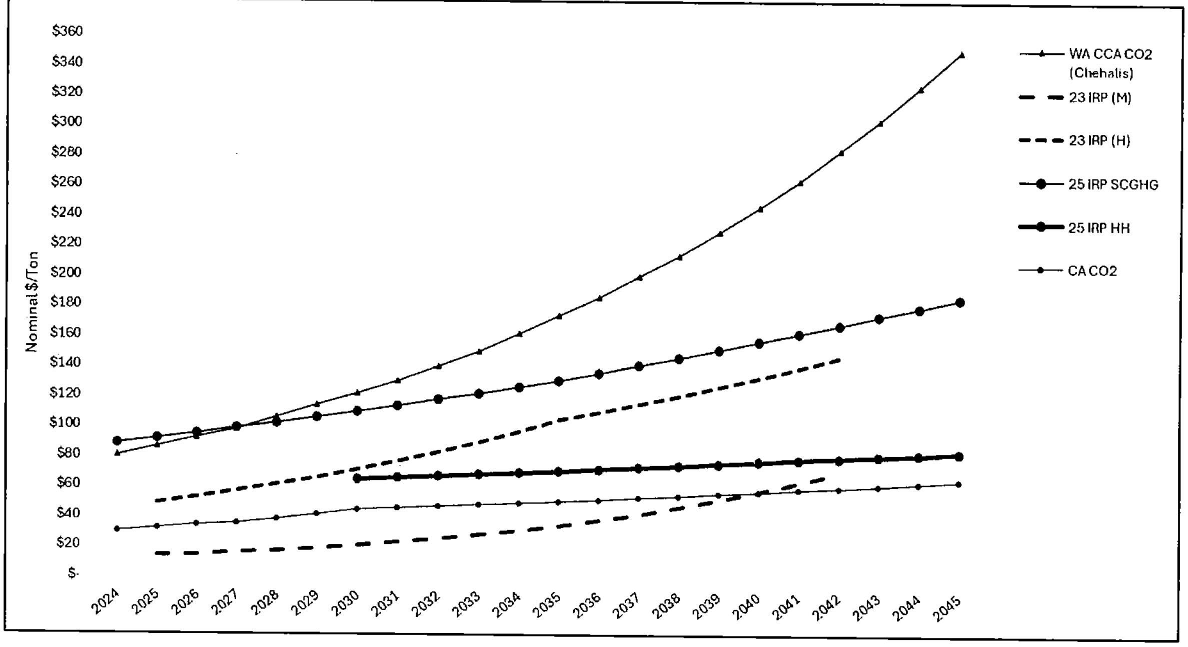
PacifiCorp used three different CO_2 price scenarios in the 2025 IRP—zero, high, and a price forecast that aligns with the social cost of greenhouse gases (SCGHG), plus a scenario reflecting compliance with current federal regulations including the currently published EPA rule 111(d). The high greenhouse 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

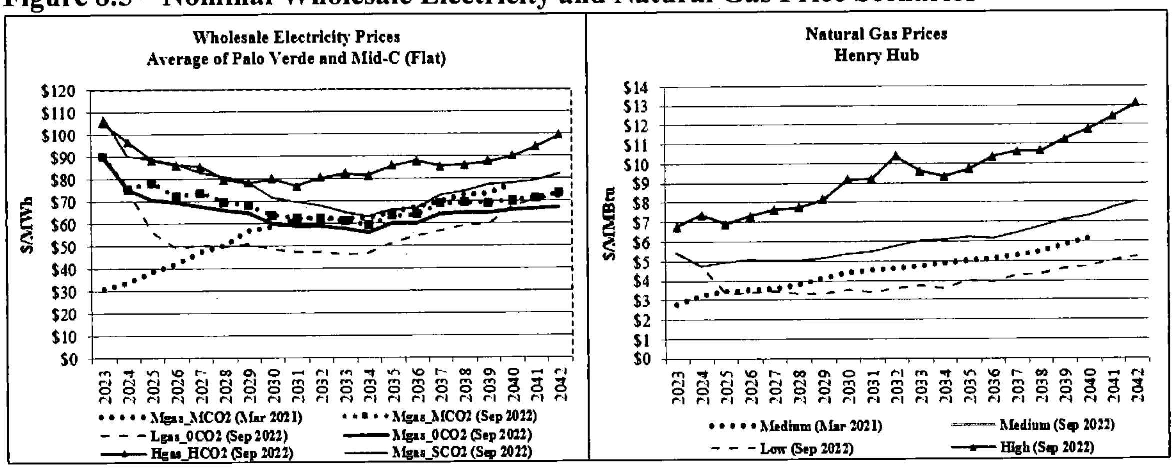
[19] The September 2024 OFPC prompt month is November 2024; October 2024 would be traded as "balance of month" when the OFPC is released.
[20] AURORAxmp is a proprietary production cost simulation model, developed by Energy Exemplar, LLC.

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
- 5th, 90th and 95th percentile PVRR
- Standard deviation
- Risk-adjustment
- Energy Not Served (ENS)

<u>Stochastic Mean PVRR</u>

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.

5^{th} and 95^{th} Percentile PVRR

The 5^{th} and 95^{th} 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 95^{th} percentile PVRR is used to derive the high-end cost risk premium for the risk-adjusted mean PVRR measure. The 5^{th} 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[a]	Existing Gas[a]	Other Existing Resources	Proxy Resources[b]
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

Jurisdiction	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

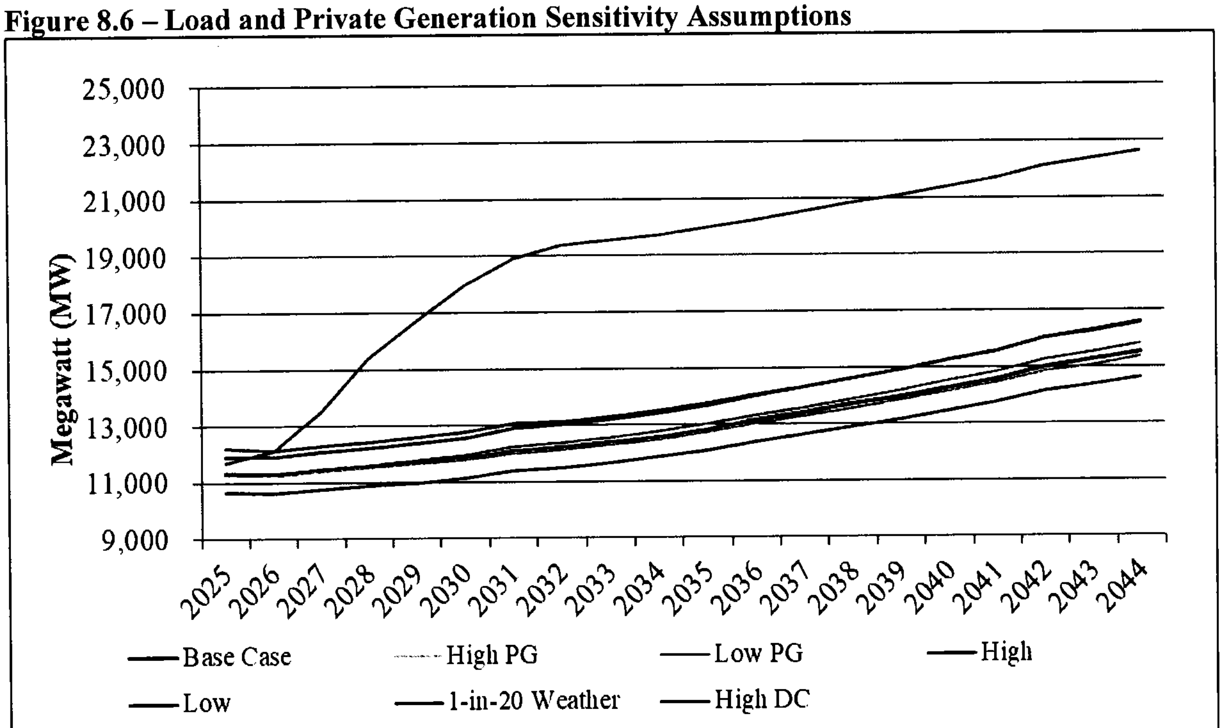
PacifiCorp identified a variety of sensitivities outlined in Table 8.7 and discussed further in Chapter 9.

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

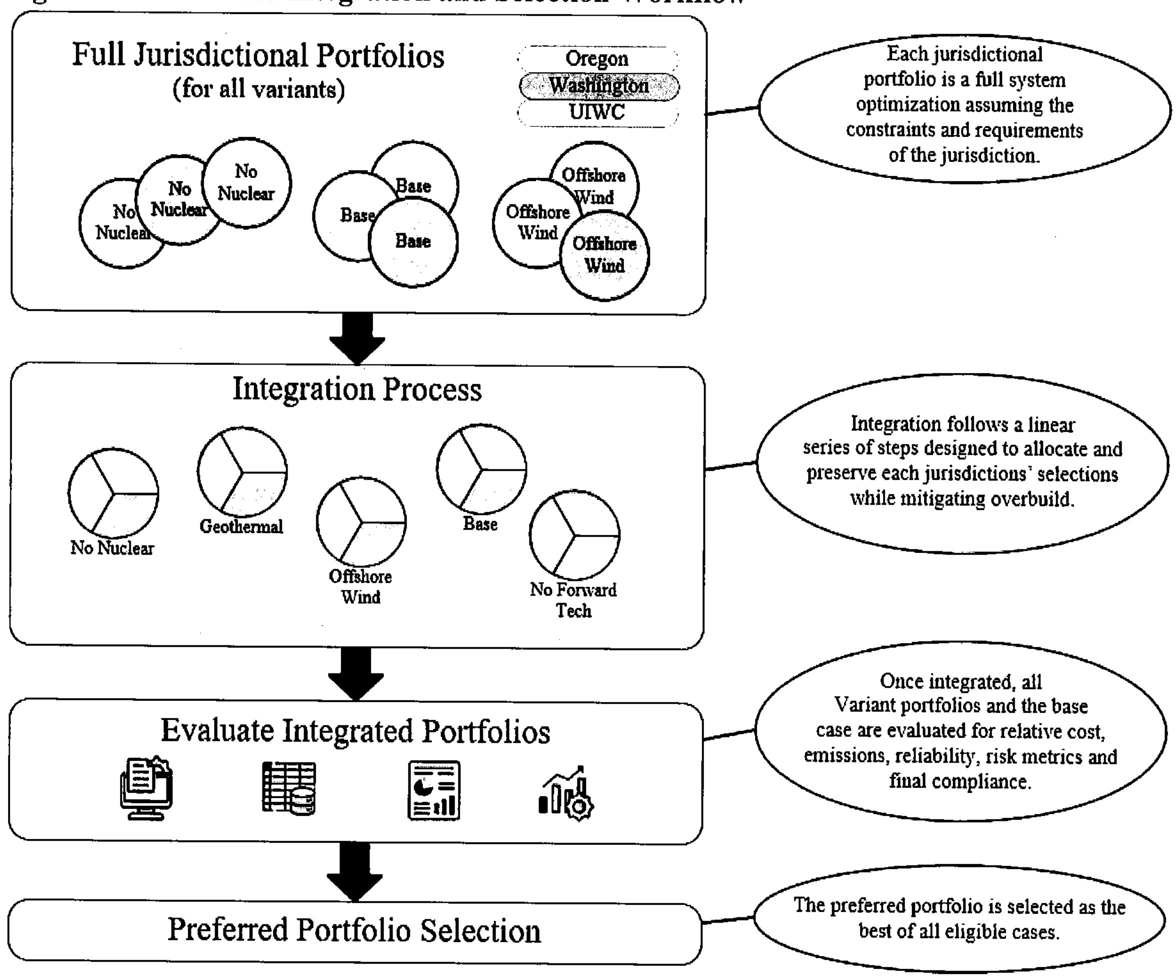
- Using cost and risk metrics to evaluate a wide range of resource portfolios, PacifiCorp selected a preferred portfolio that builds on its vision to deliver energy affordably, reliably, and responsibly.
- PacifiCorp's selection of the 2025 IRP preferred portfolio is supported by comprehensive data analysis 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™ 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

	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
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

Resource	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
	Installed Capacity, MW																					
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

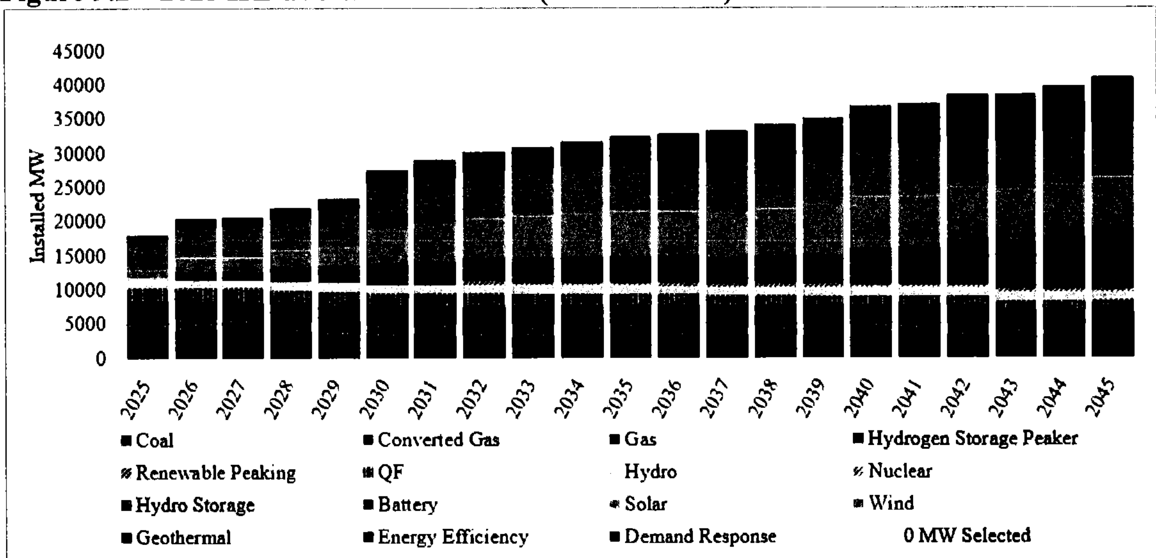
Summary Portfolio Capacity by Resource Type and Year, Installed MW

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 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]

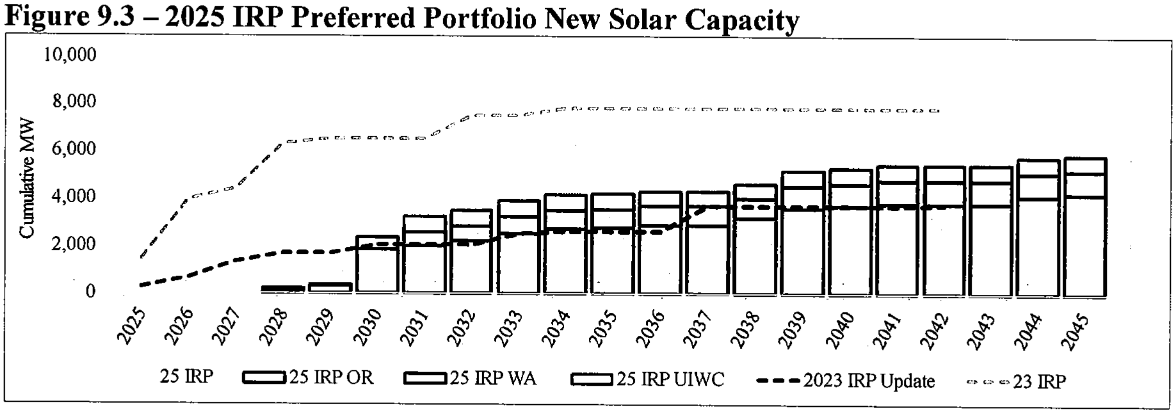
	Export (MW)	Import (MW)	Interconnect (MW)	Build Investment ($m)	Build (%)	From	To
2026 Utah South - Wasatch Front: 138 kV reinforcement #1	250	250	250	30	100%	Utah South	Wasatch Front
2028 Cluster 1 Area 11: Willamette Valley	0	0	199	14	100%	n/a	n/a
Cluster 1 Area 14: Summer Lake	400	400	400	111	100%	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.

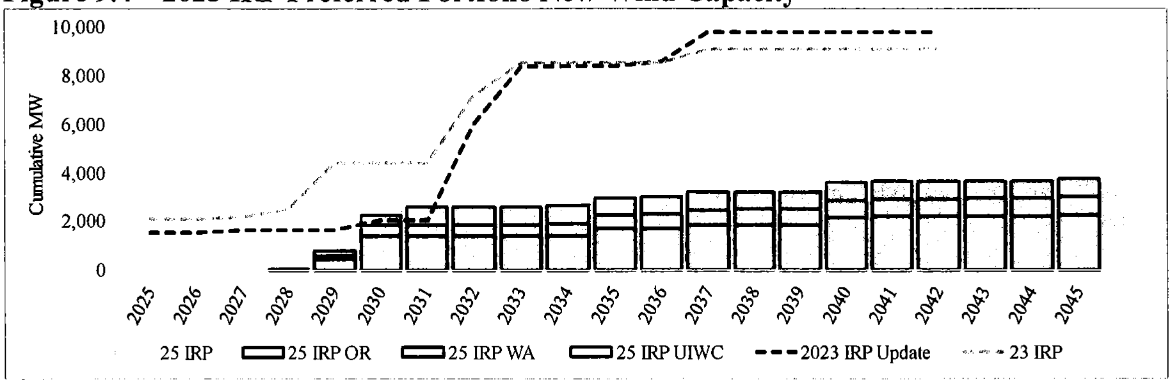
Figure 9.3 – 2025 IRP Preferred Portfolio New Solar Capacity



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.

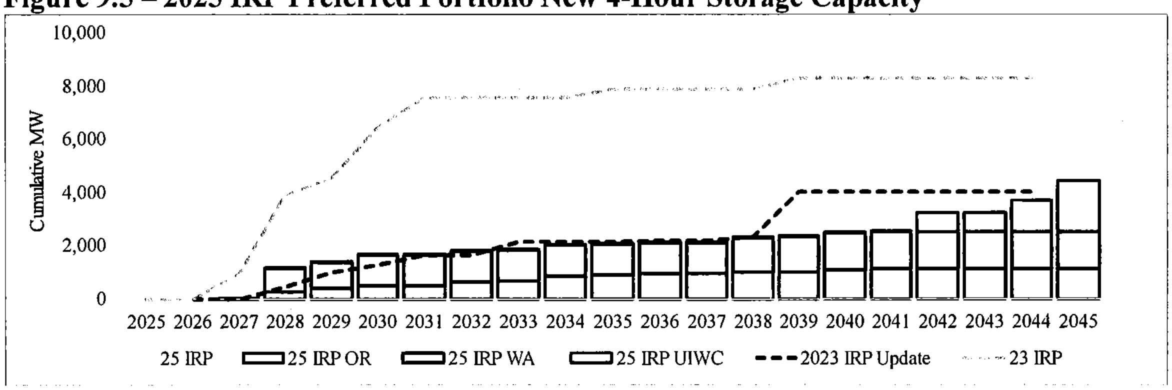
Figure 9.4 – 2025 IRP Preferred Portfolio New Wind Capacity



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.

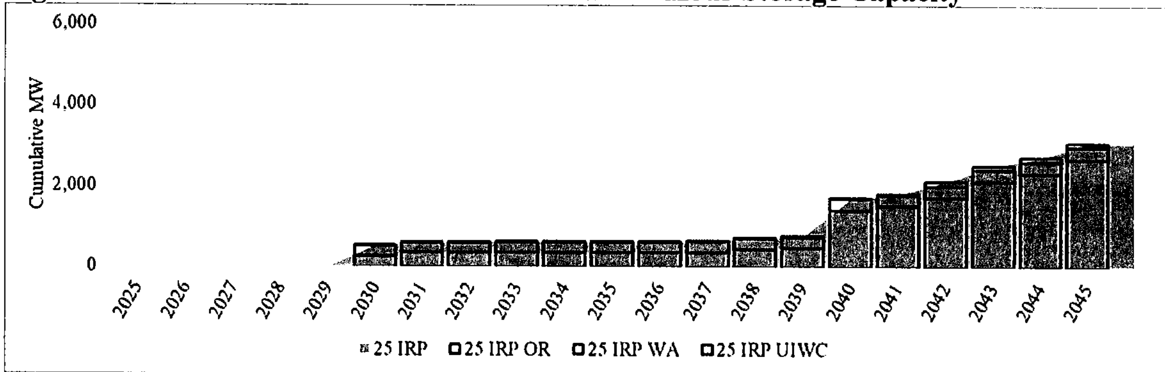
Figure 9.5 – 2025 IRP Preferred Portfolio New 4-Hour Storage Capacity[1,2]



[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]

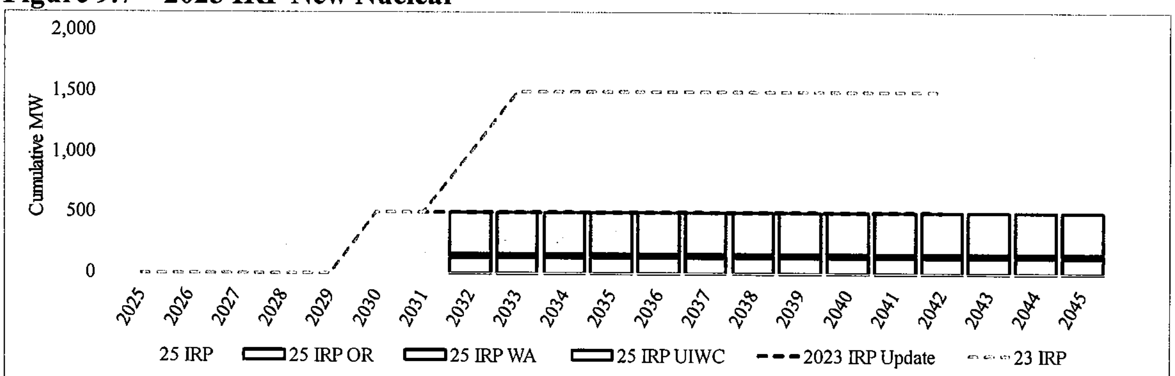


[1]The 2025 IRP preferred portfolio also includes 41 MW of renewable peaking resources by the end of the planning horizon.

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]

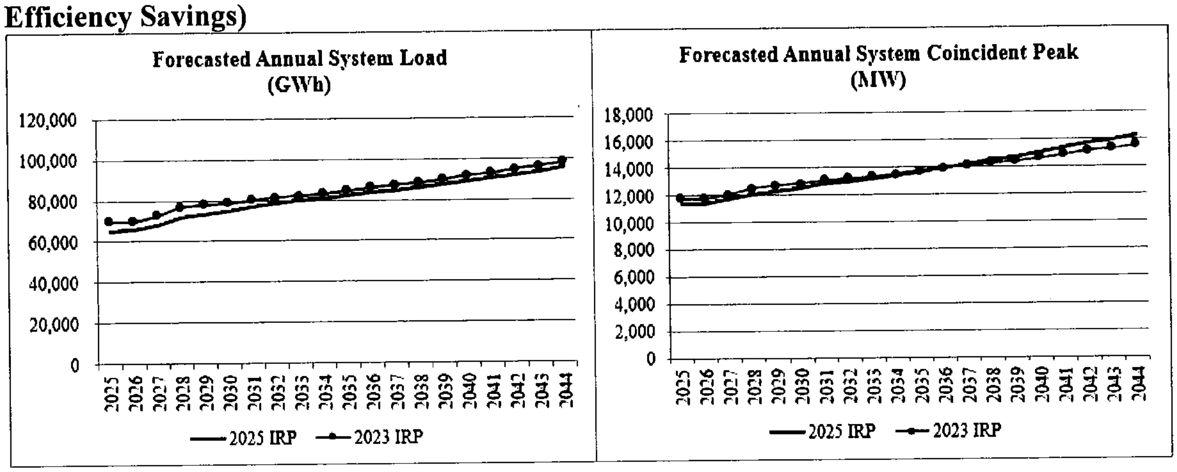


[1] While the 500 MW advanced nuclear Natrium™ demonstration project is currently scheduled to come online by the fall of 2031, the PLEXOS model works best with beginning of year start dates for expansion candidates, so a start date of 1/1/2032 was assumed for the Natrium™ demonstration project in modeling.

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)

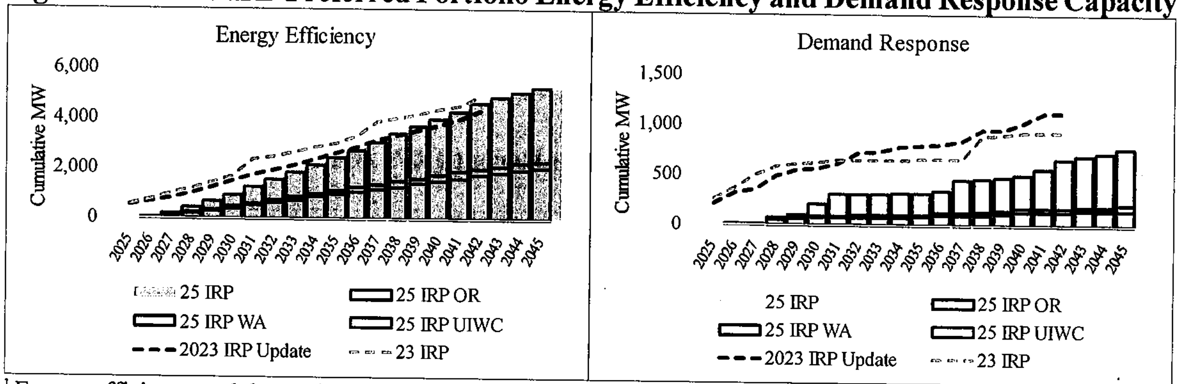


DSM resources continue to play a key role in PacifiCorp's resource mix. The chart to the left in Figure 9.9 compares total energy efficiency capacity savings in the 2025 IRP preferred portfolio relative to the 2023 IRP preferred portfolio. Cumulative capacity of energy efficiency programs in the 2025 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

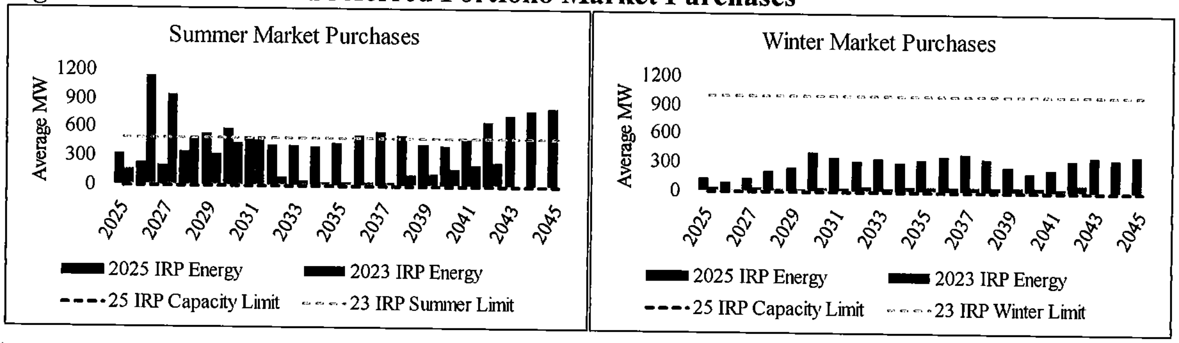
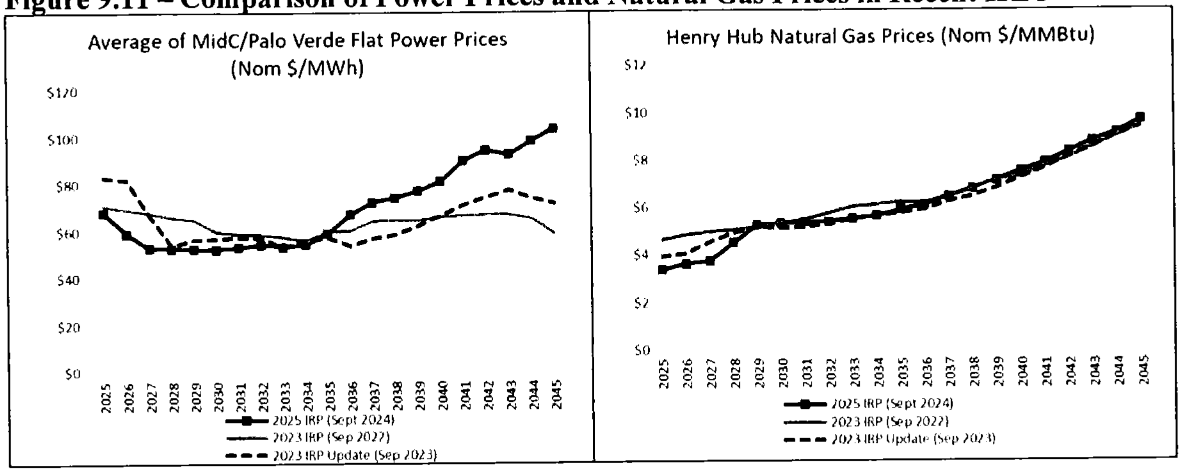


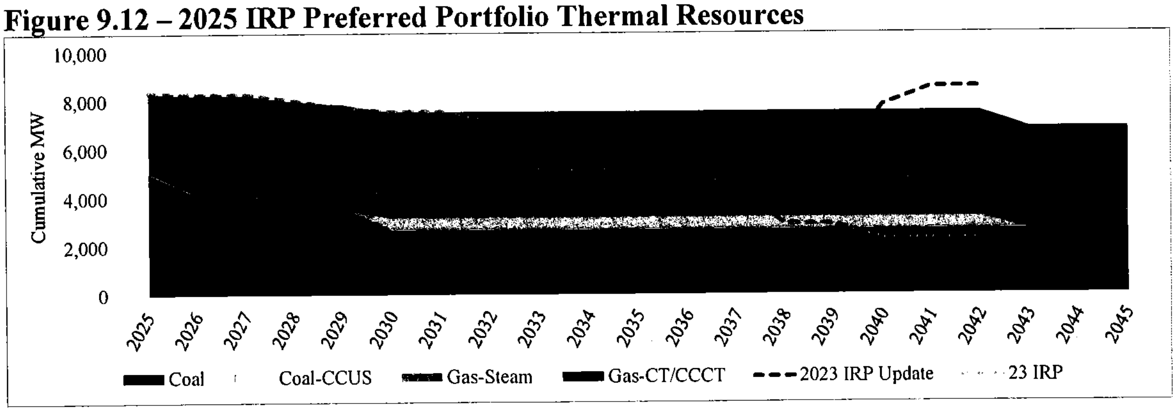
Figure 9.11 – Comparison of Power Prices and Natural Gas Prices in Recent IRPs



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

[illegible]			
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

[illegible]		
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-

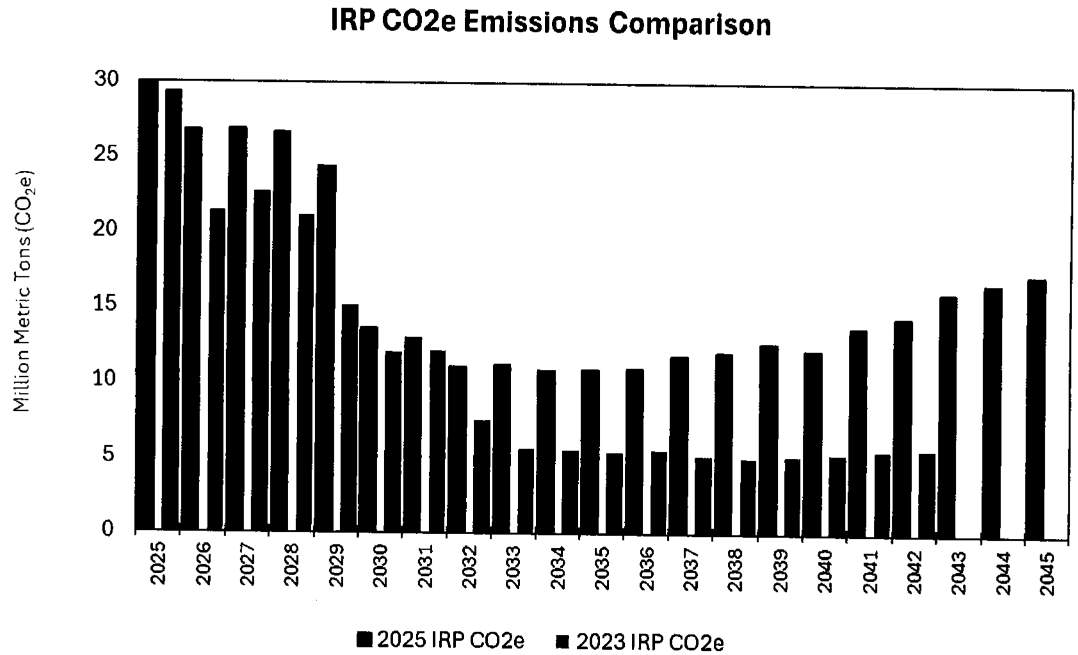
[6] PacifiCorp's Chehalis and Hermiston natural gas units are subject to Washington and Oregon regulation, respectively, and a final determination of state allocations, potential operational restrictions and economics continue to be evaluated.

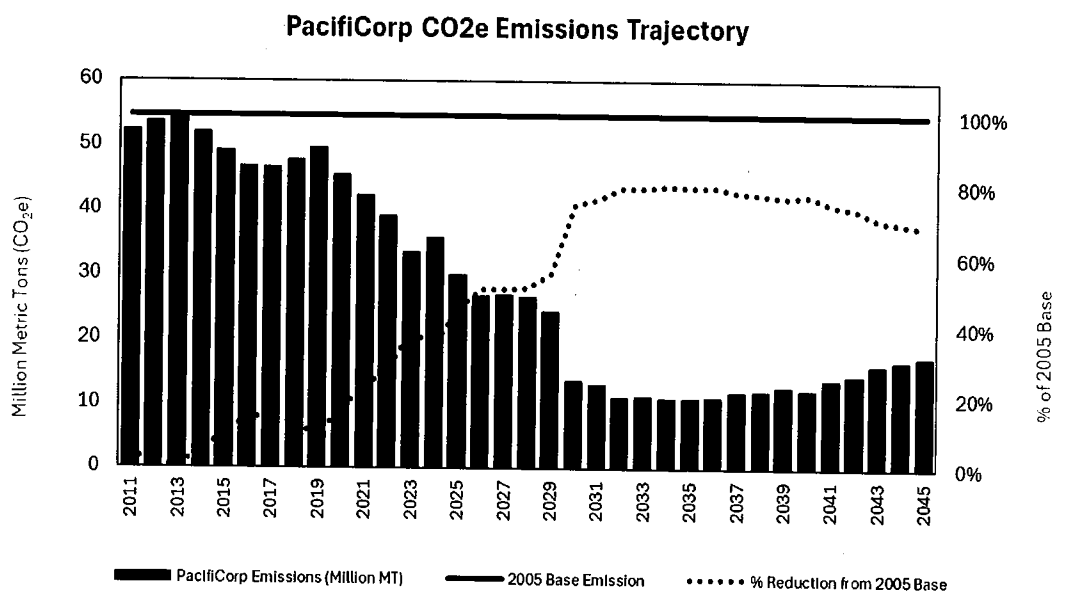
policy scenario used to forecast emissions. No CO2 price was included in the dispatch of the 2025 IRP preferred portfolio used to forecast emissions. The 2023 IRP also modeled the EPA's proposed implementation of the Ozone Transport Rule as a significant dispatch target on emissions. No dispatch target 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

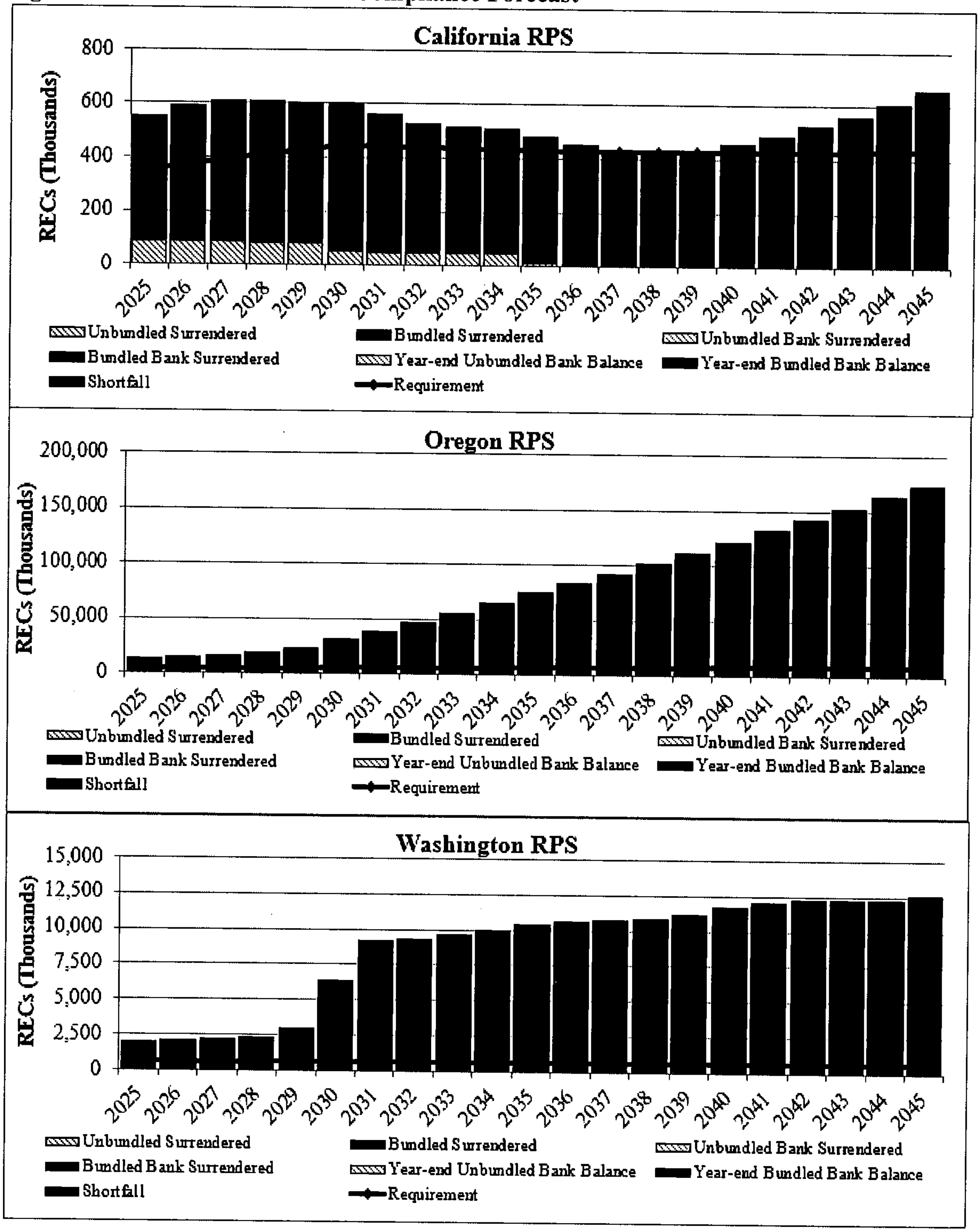
Figure 9.14 shows PacifiCorp's renewable portfolio standard (RPS) compliance forecast for California, Oregon, and Washington after accounting for unbundled REC purchases and new renewable resources in the preferred portfolio. While new resources are included in the preferred portfolio as cost-effective 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

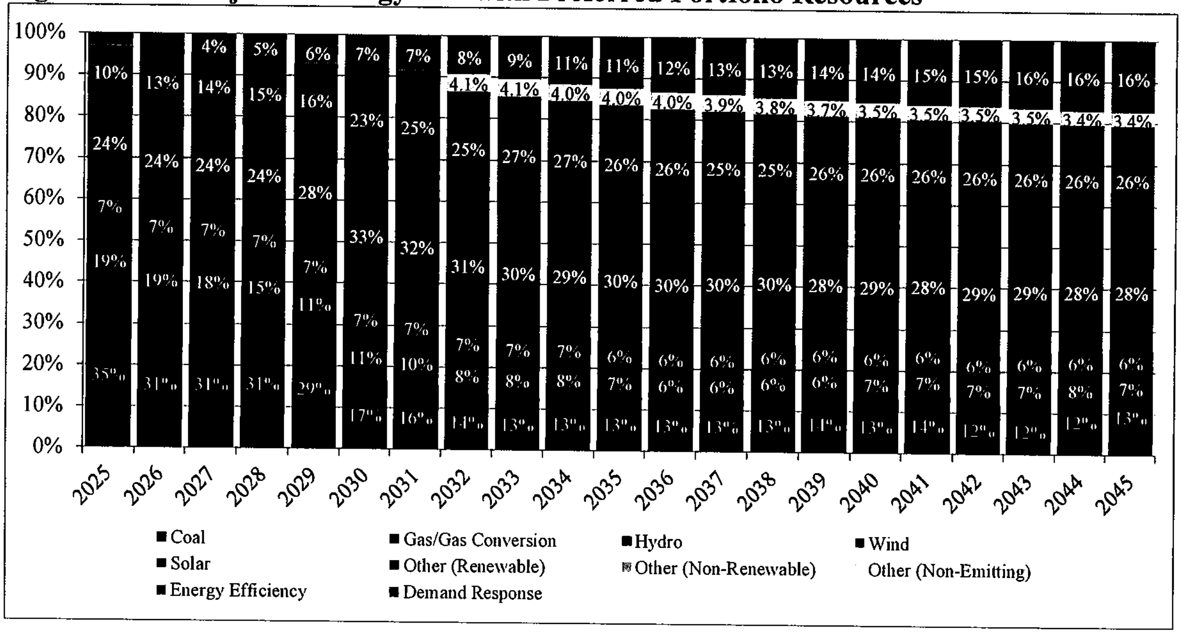
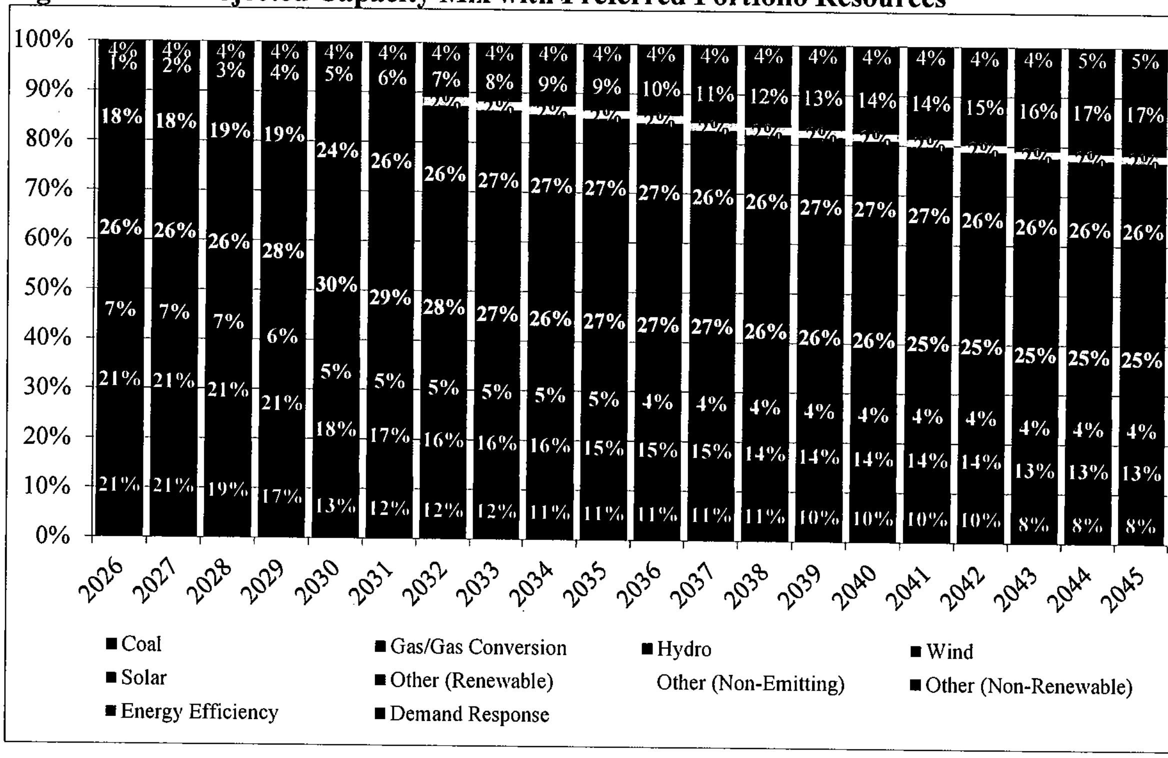


Figure 9.16 – Projected Capacity Mix with Preferred Portfolio Resources



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																						
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

Resource	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
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 Purchase	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 Purchase	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	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
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 Purchase	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	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
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 Purchase	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	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
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]

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

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

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]

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]

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	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	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

	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]

	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	UTWC	OR	WA	Description
MN - 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		✓		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		✓		No nuclear resources are eligible for selection
MN - Offshore Wind		✓		Counterfactual to preferred portfolio selection
MN - No Forward Technology		✓		No nuclear, hydrogen or 100-hour storage, or biodiesel peaking
MN - Geothermal		✓		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	[illegible]
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	[illegible]	35,127	$7,615	[illegible]	42,917	$8,255	[illegible]	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	[illegible]
Integrated Geothermal MN	29,208	$2,146	[illegible]	29,946	$2,434	[illegible]	37,188	$2,525	[illegible]	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	[illegible]
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	[illegible]	30,088	$2,575	[illegible]	37,904	$3,242	[illegible]	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	[illegible]
Integrated No CCS MN	25,847	$1,232	8	361,938	100,514	[illegible]
Integrated No Nuclear MN	28,638	$4,023	[illegible]	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	[illegible]	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	[illegible]
Integrated No CCS MN	35,762	$4,264	[illegible]	219,378	45,302	[illegible]
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	[illegible]	194,780	20,703	8
Integrated No Future Tech MN	35,902	$4,404	[illegible]	207,187	33,110	[illegible]
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

Case - SC	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 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	[illegible]
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	[illegible]	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	[illegible]
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

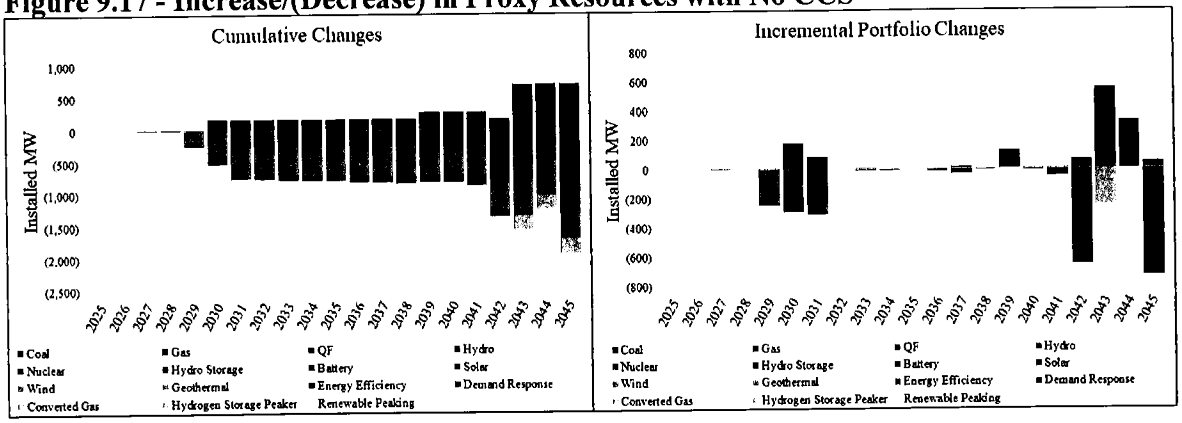
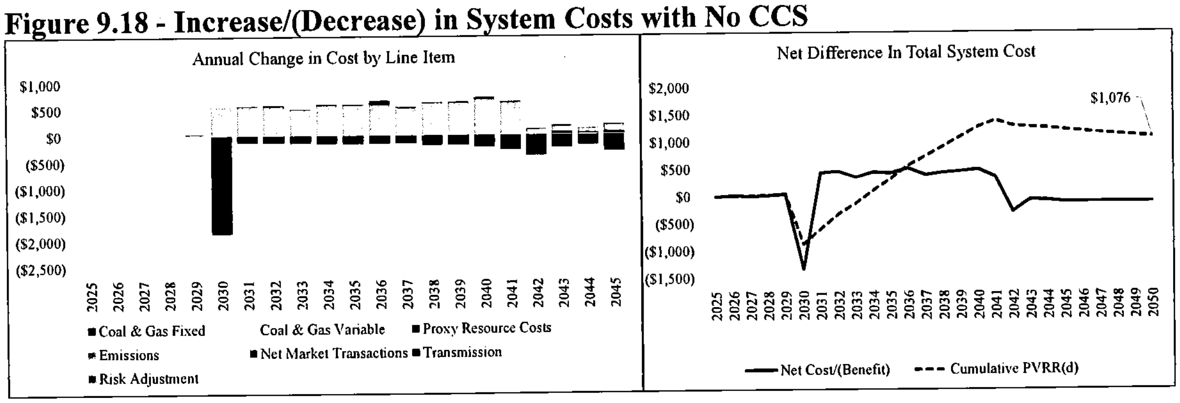


Figure 9.18 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when CCS is removed from the portfolio. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) 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

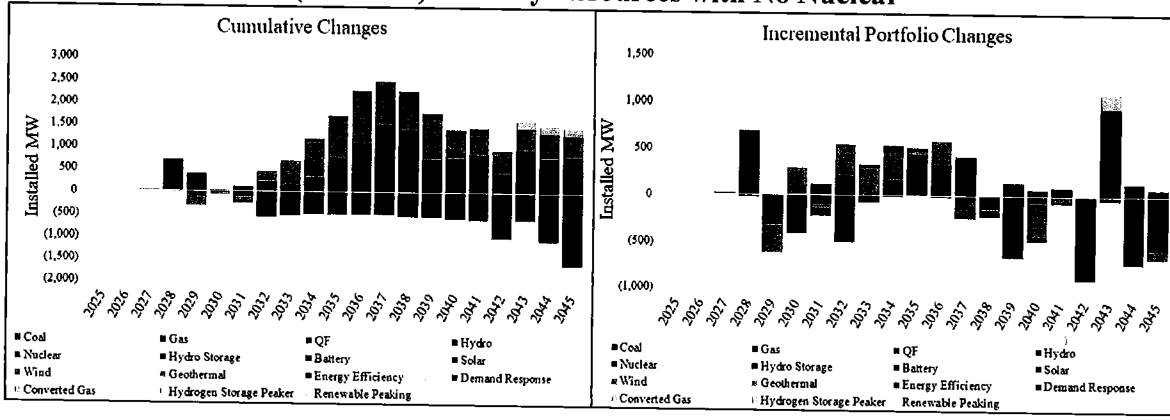
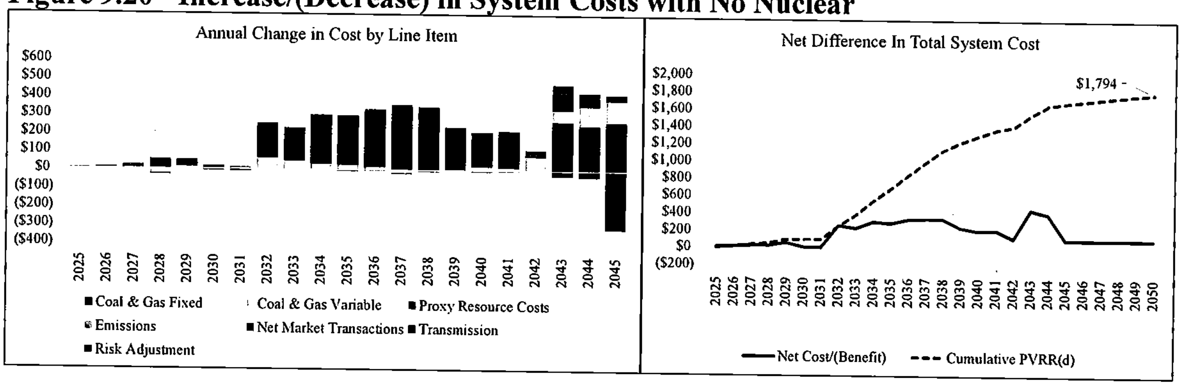


Figure 9.20 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when nuclear projects are removed from the portfolio. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid 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

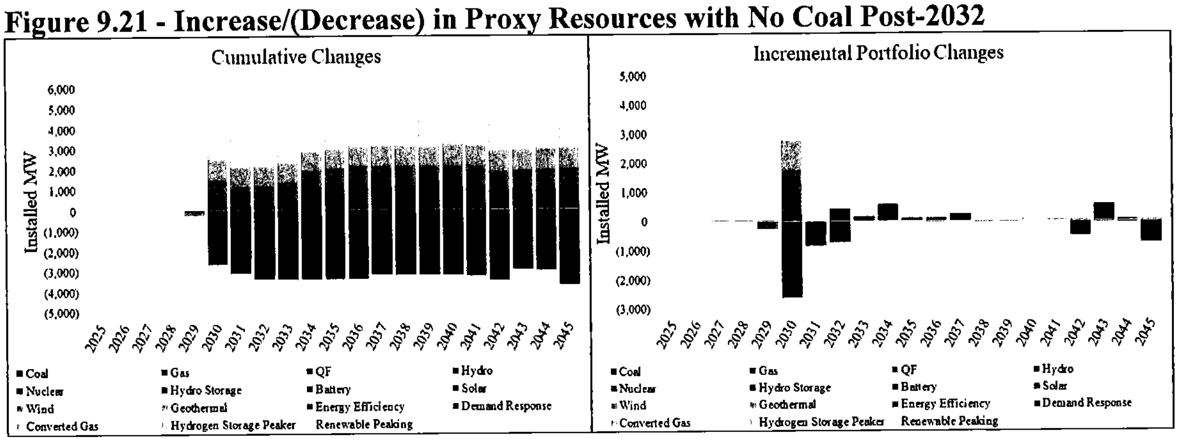
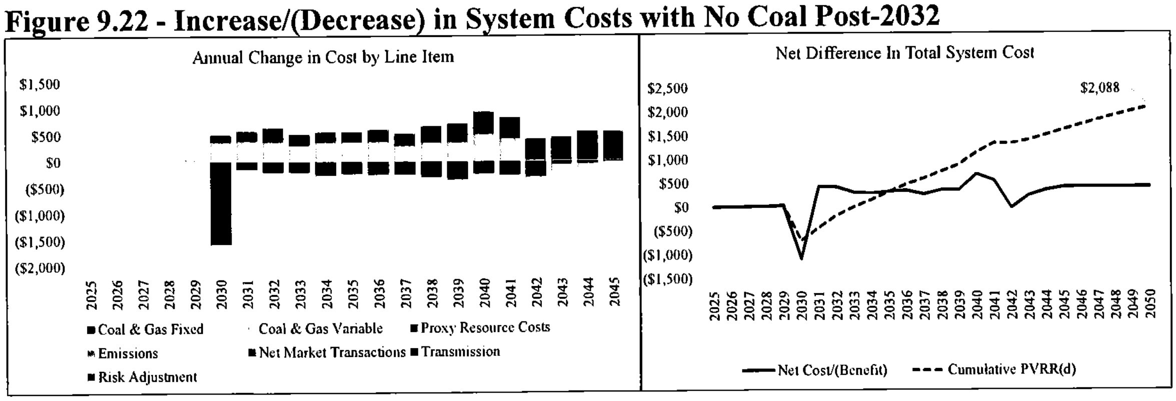


Figure 9.22 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when coal is no longer allowed in the portfolio after 2032. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the 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

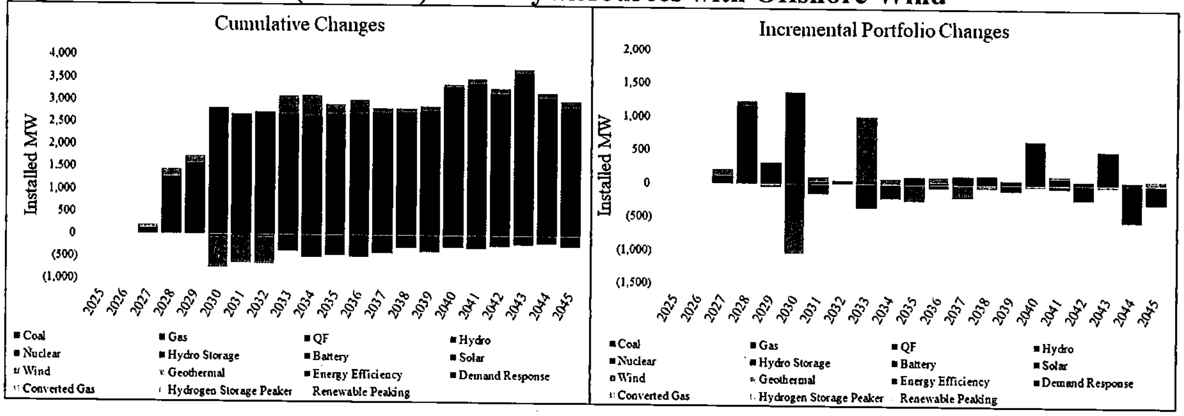
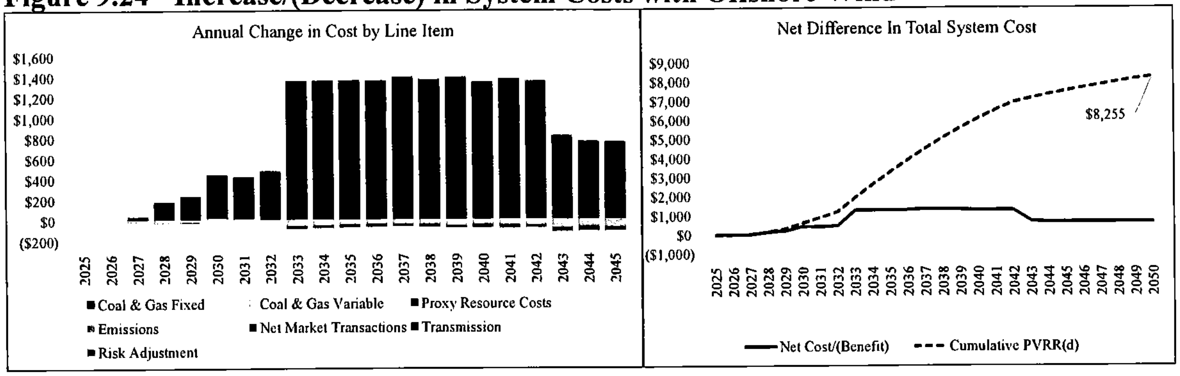


Figure 9.24 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when offshore wind is forced into the various jurisdictional portfolios. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total 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

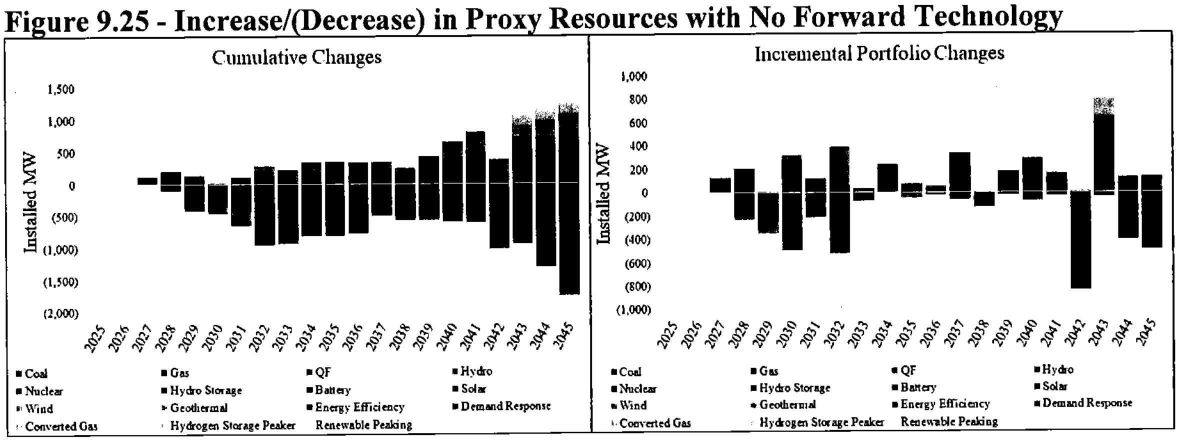
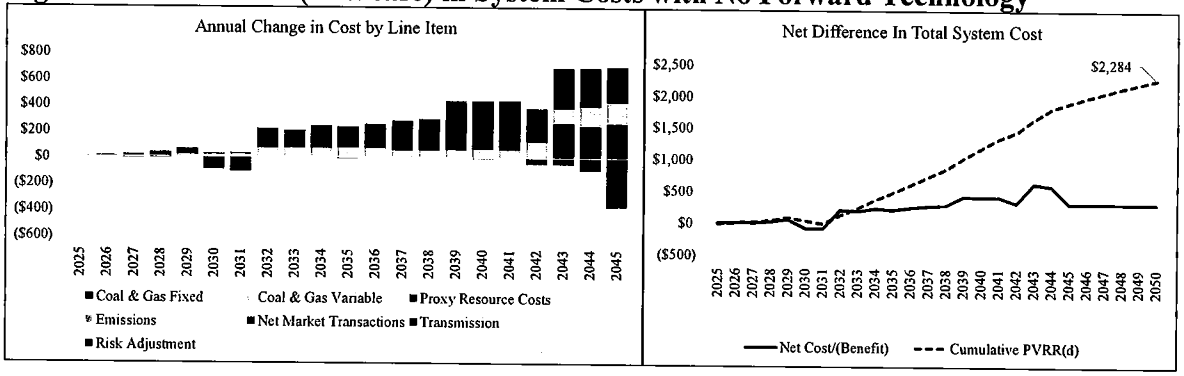


Figure 9.26 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when forward technologies are removed from the portfolio. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the 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

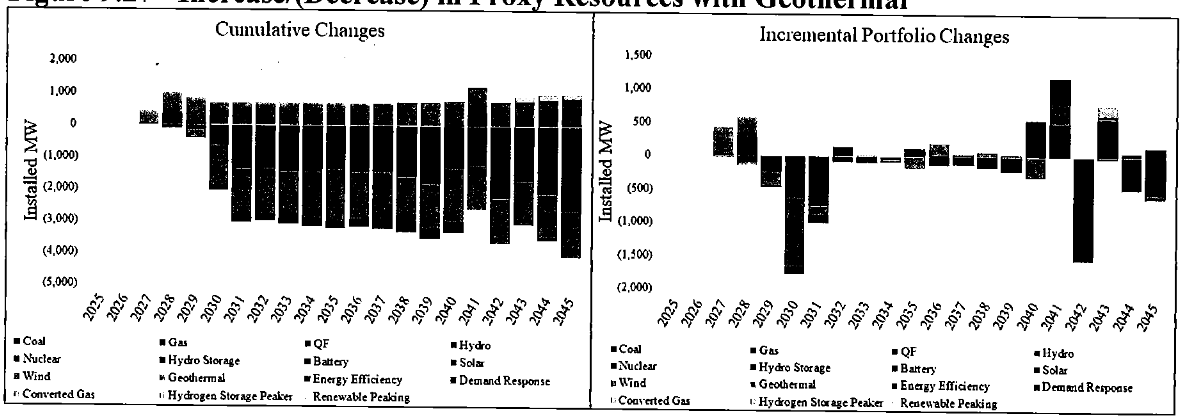
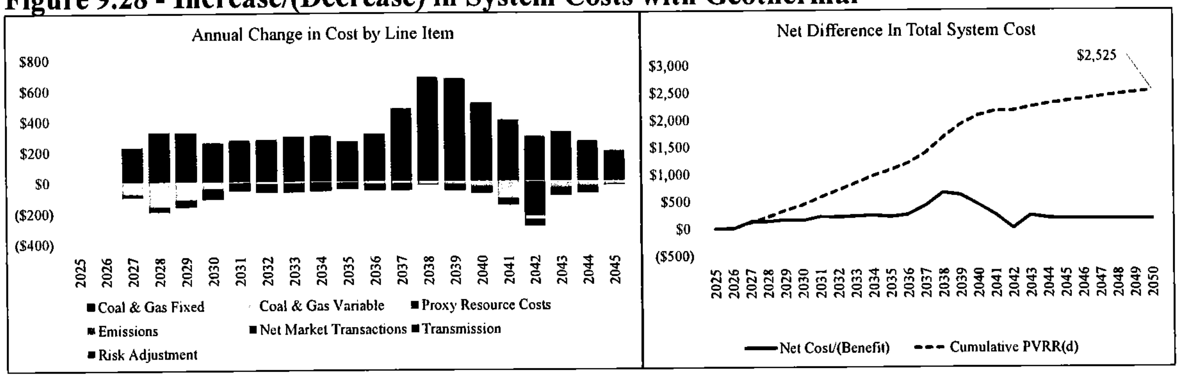


Figure 9.28 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when geothermal is forced into the various jurisdictional portfolios. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total 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

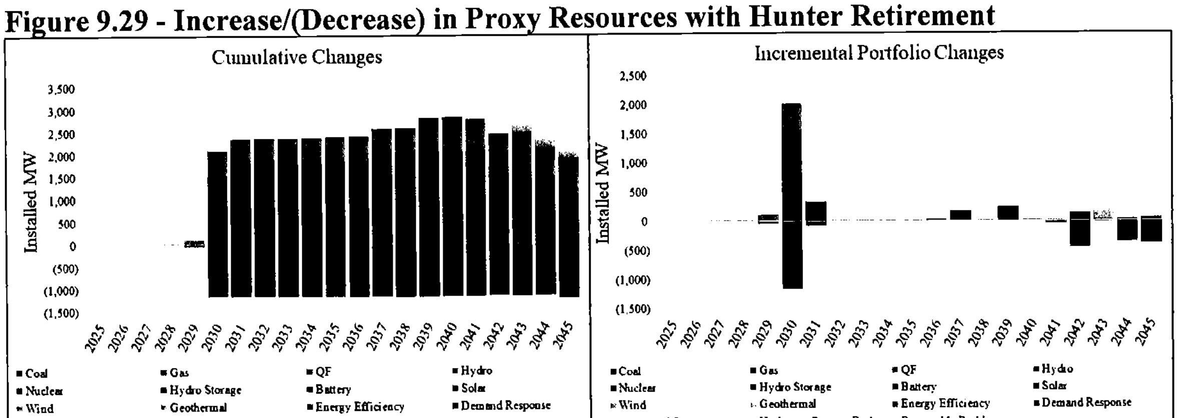
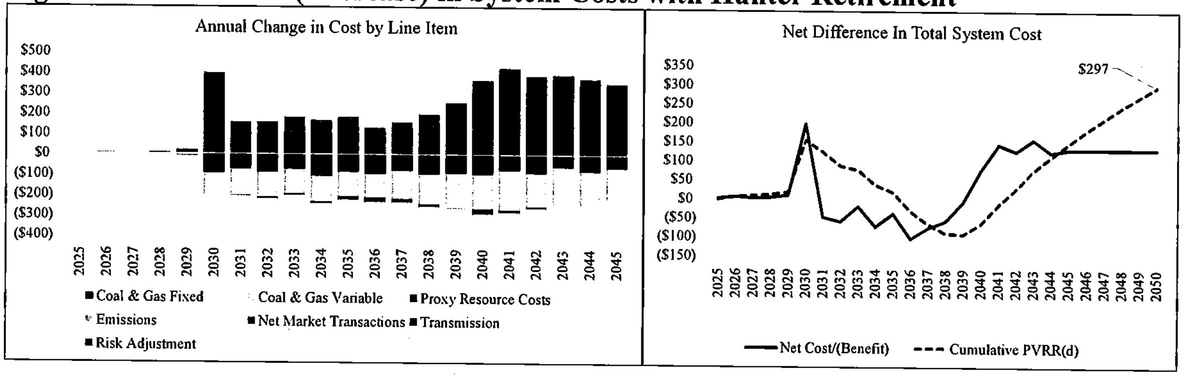


Figure 9.30 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when Hunter is forced to retire in 2030. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) 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

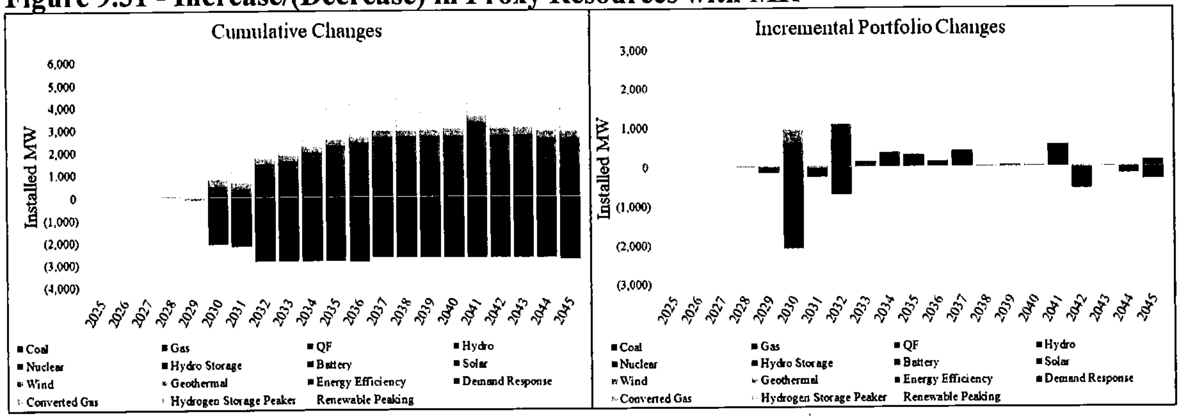
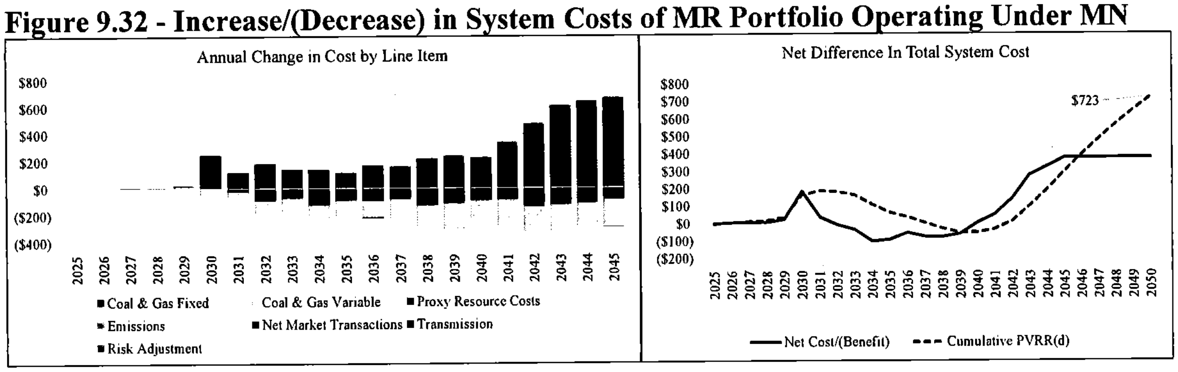


Figure 9.32 summarizes changes in system costs, based on ST model results operating MN price policy portfolio under the MN price policy assumptions. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) 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

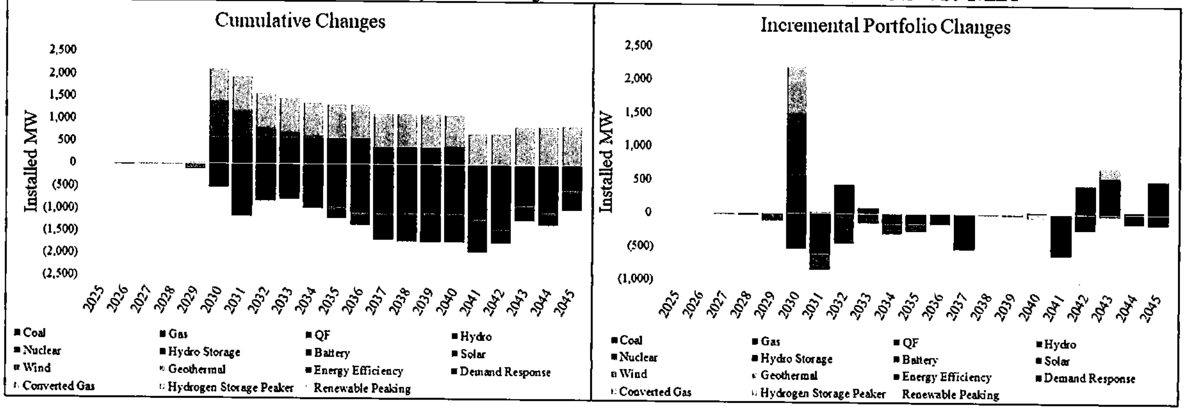
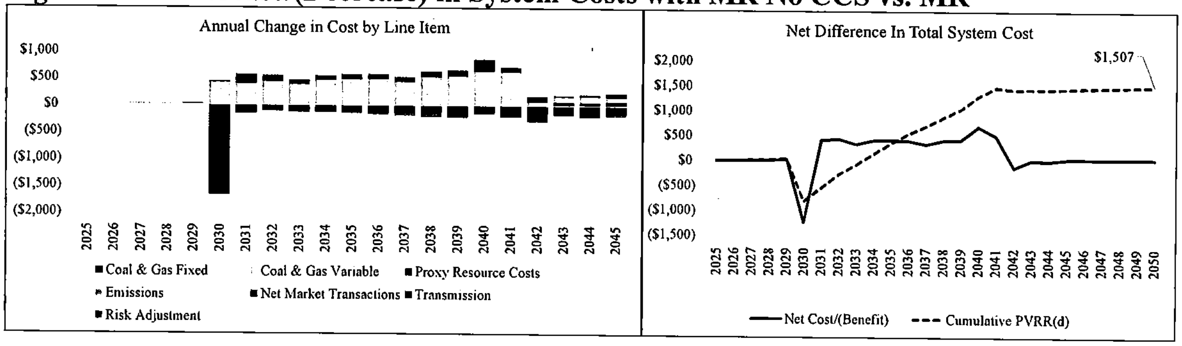


Figure 9.34 summarizes changes in system costs, based on ST model results using MR price-policy assumptions, when CCS is removed from the portfolio. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) 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

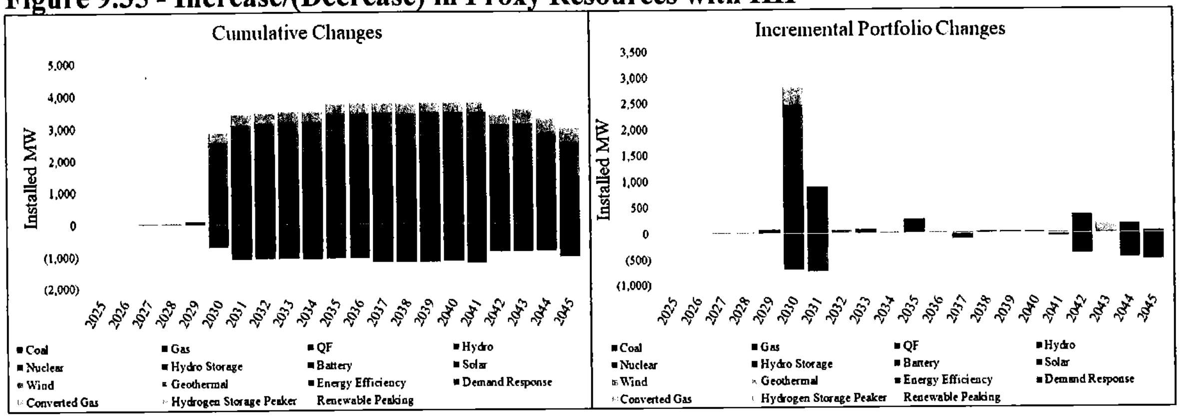
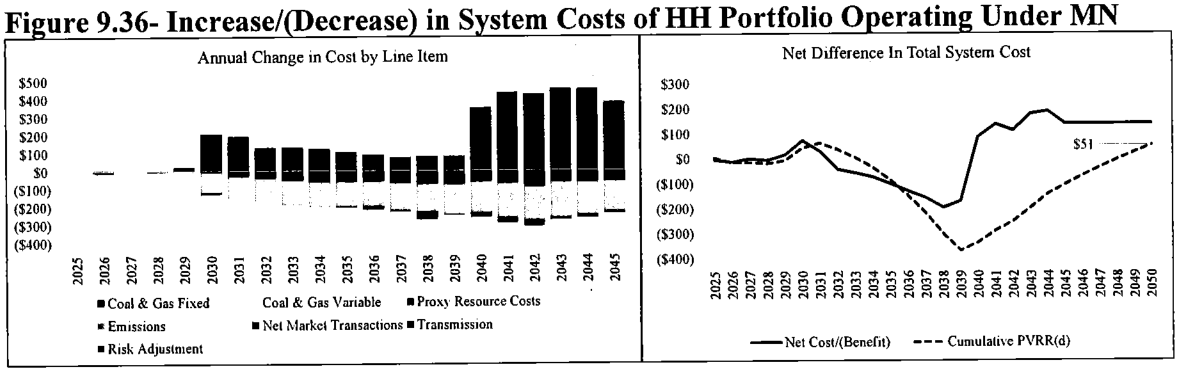


Figure 9.36 summarizes changes in system costs, based on ST model results operating HH price policy portfolio under the MN price policy assumptions. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) 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

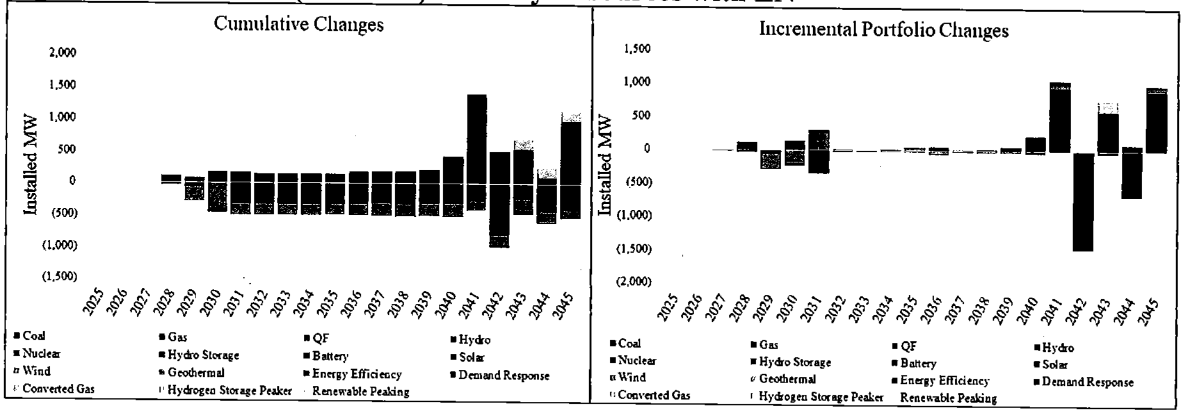
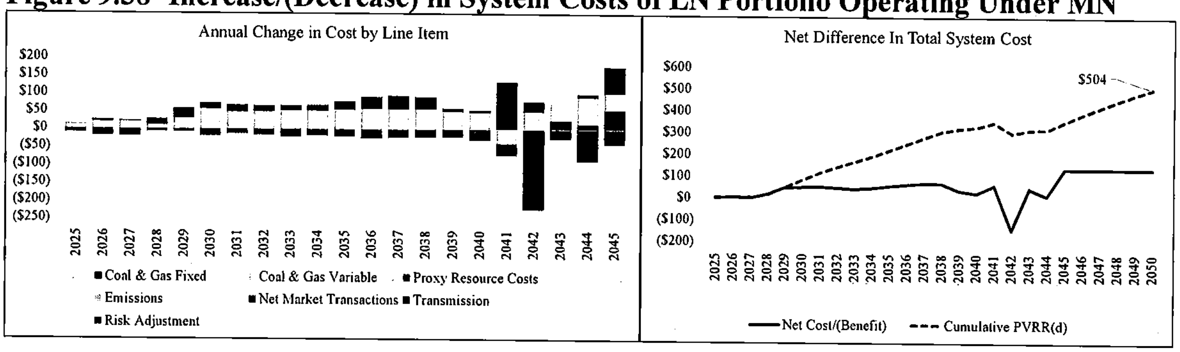


Figure 9.38 summarizes changes in system costs, based on ST model results operating LN price policy portfolio under the MN price policy assumptions. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) 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

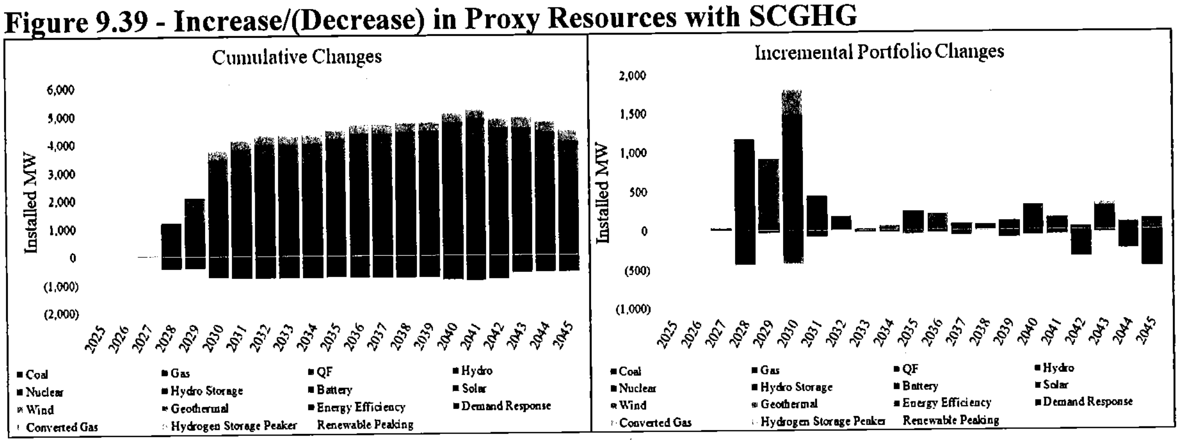
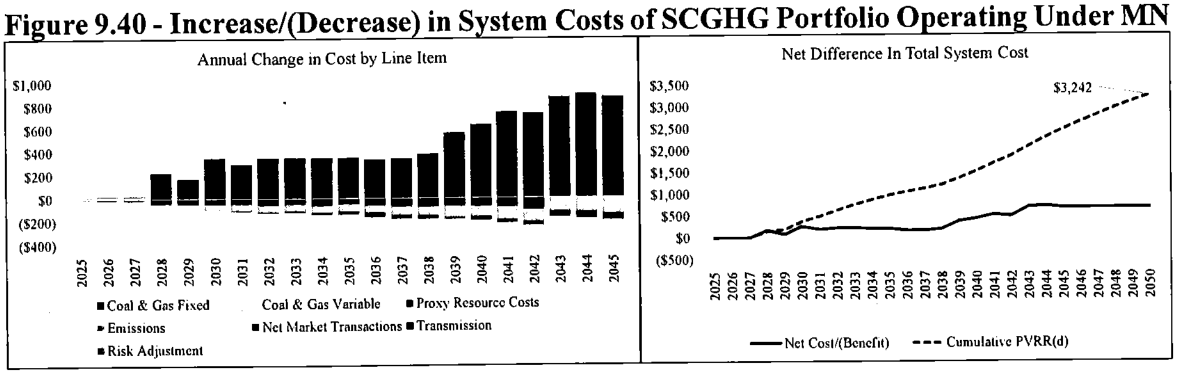


Figure 9.40 summarizes changes in system costs, based on ST model results operating SCGHG price policy portfolio under the MN price policy assumptions. The graph on the left shows annual changes in cost by category and the graph on the right shows annual net changes in total costs (the solid black line) 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

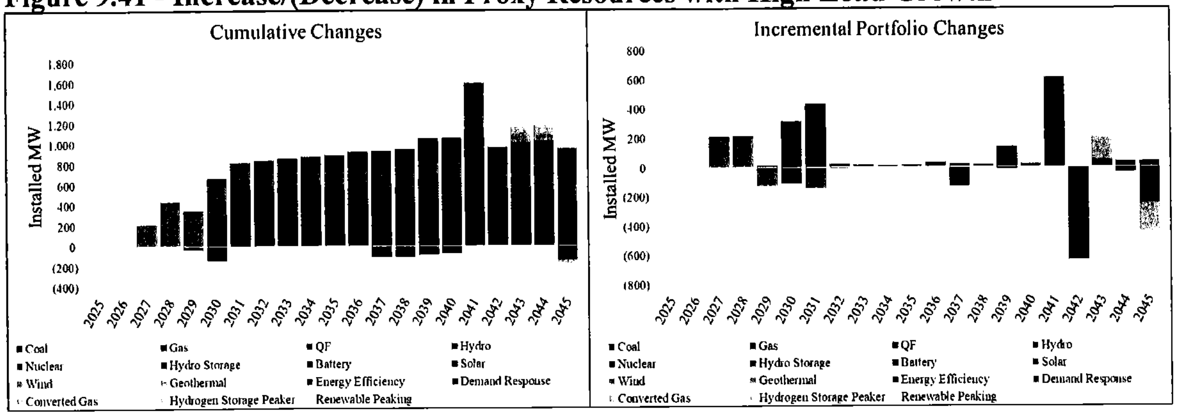
High Load Growth

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

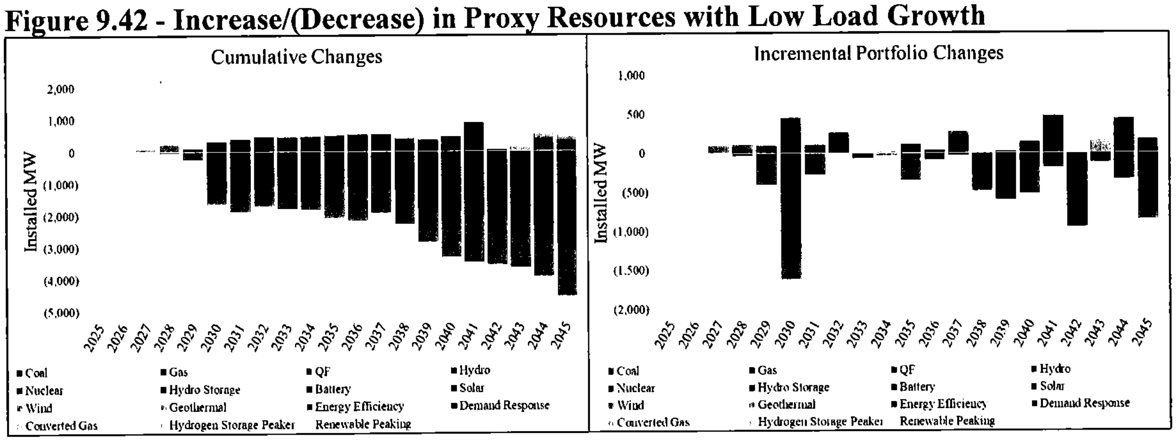


Low Load Growth

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

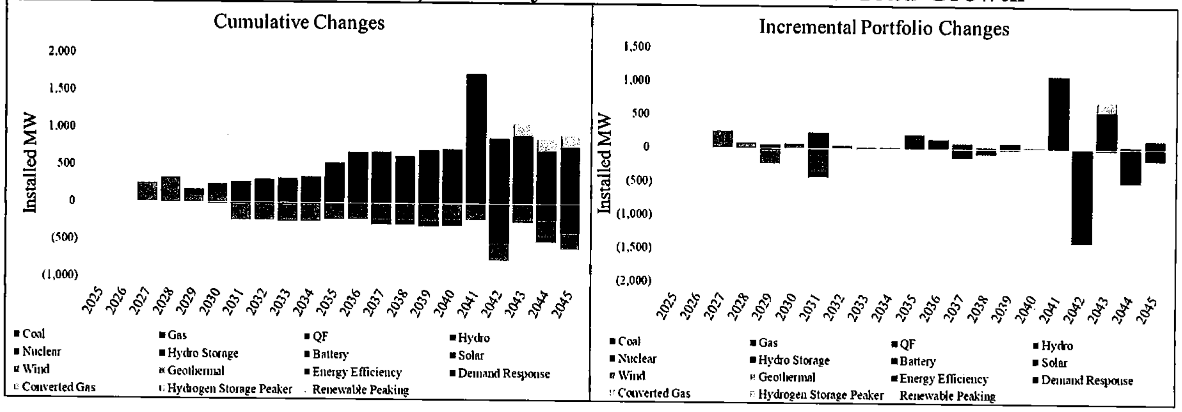


1-in-20 Peak Load Growth

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

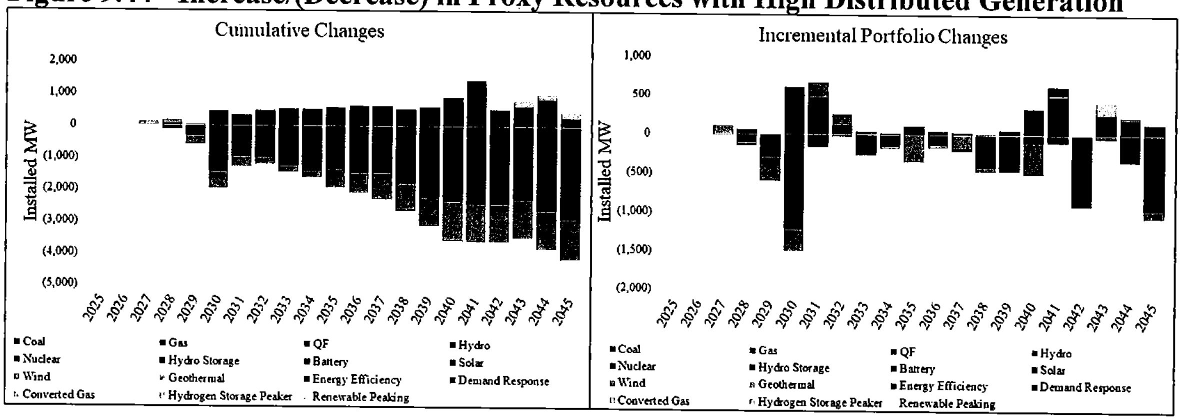


High Distributed Generation Growth

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

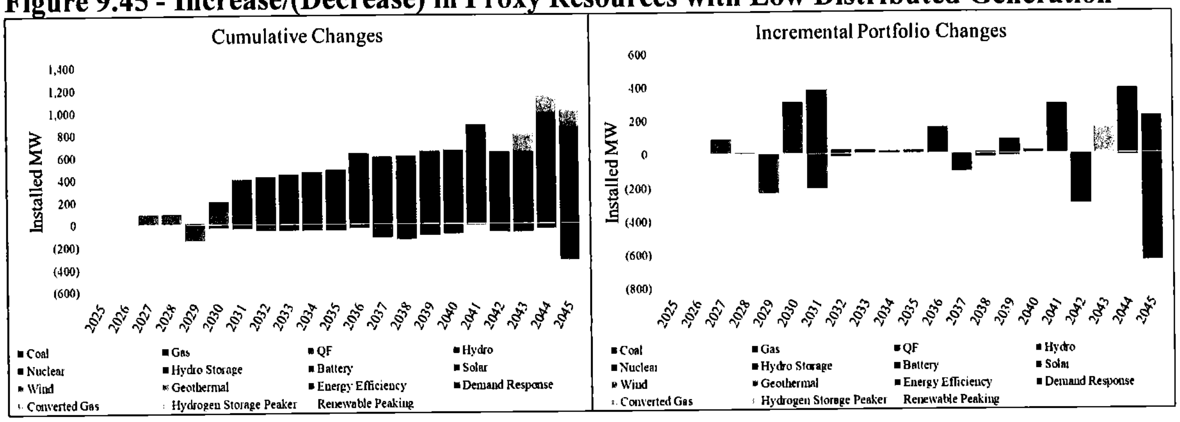


Low Distributed Generation Growth

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

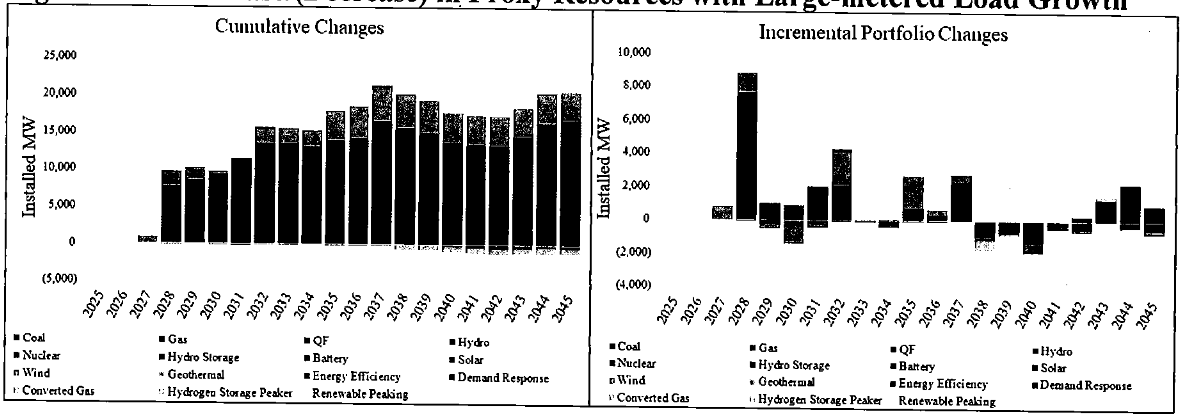
The large-metered load growth sensitivity evaluates what selections of both resources and transmission would be required to serve all large-metered load that could potentially come online in PacifiCorp service territory. The purpose of this study is to identify which resources might be needed if the 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

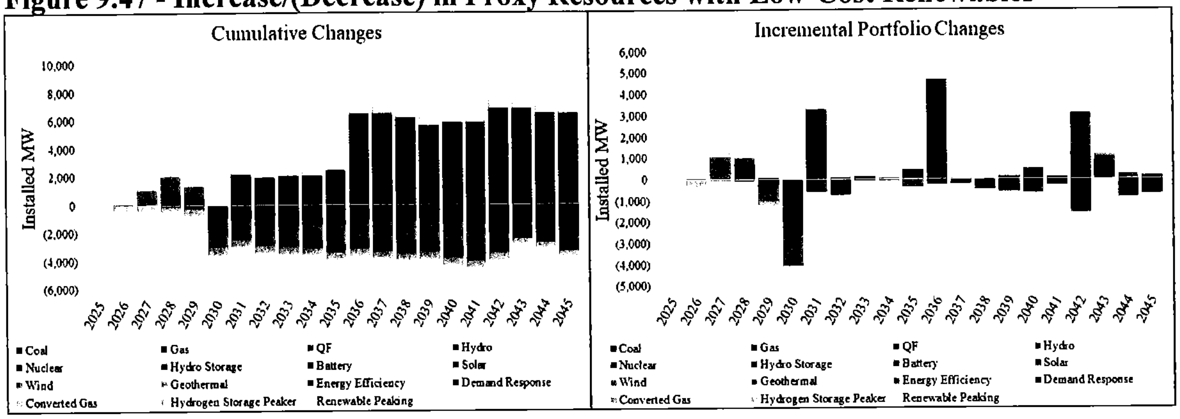


Low-Cost Renewables

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

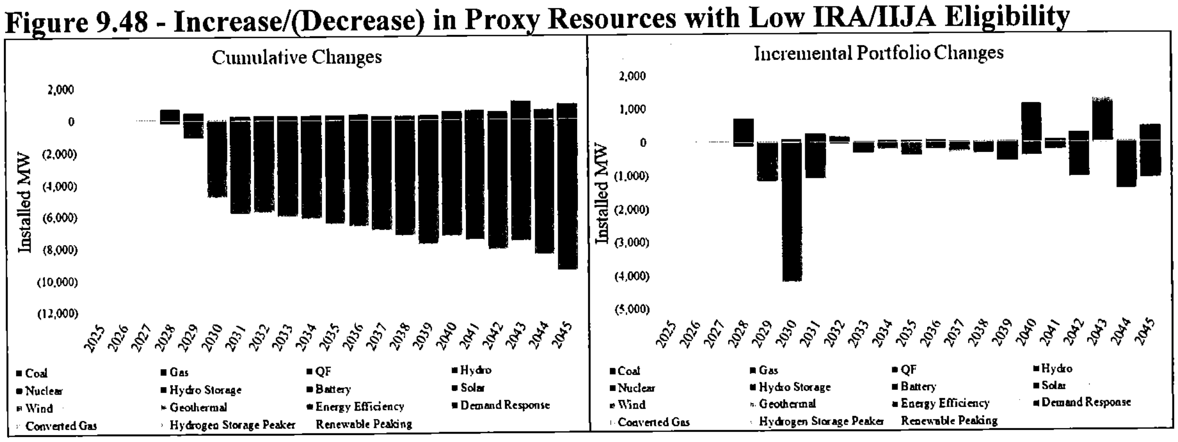


Low IRA/IIJA Eligibility

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

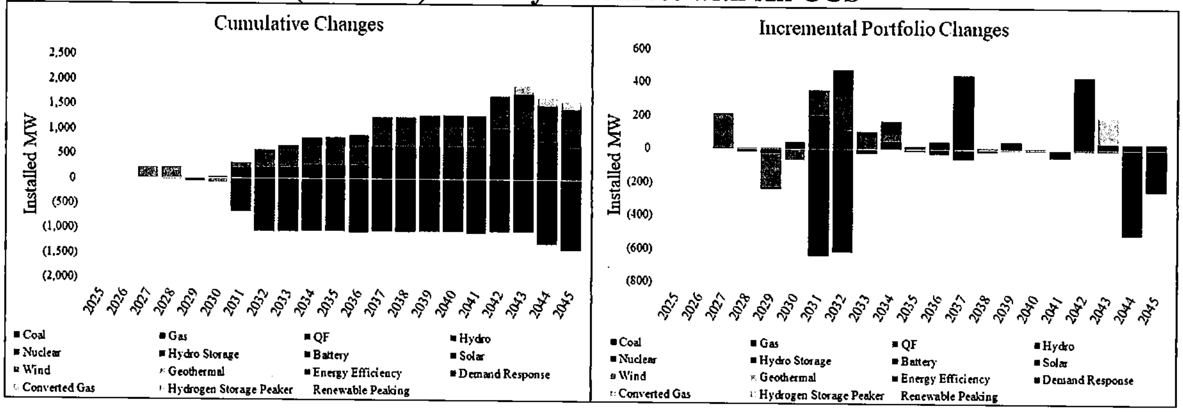


All CCS

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

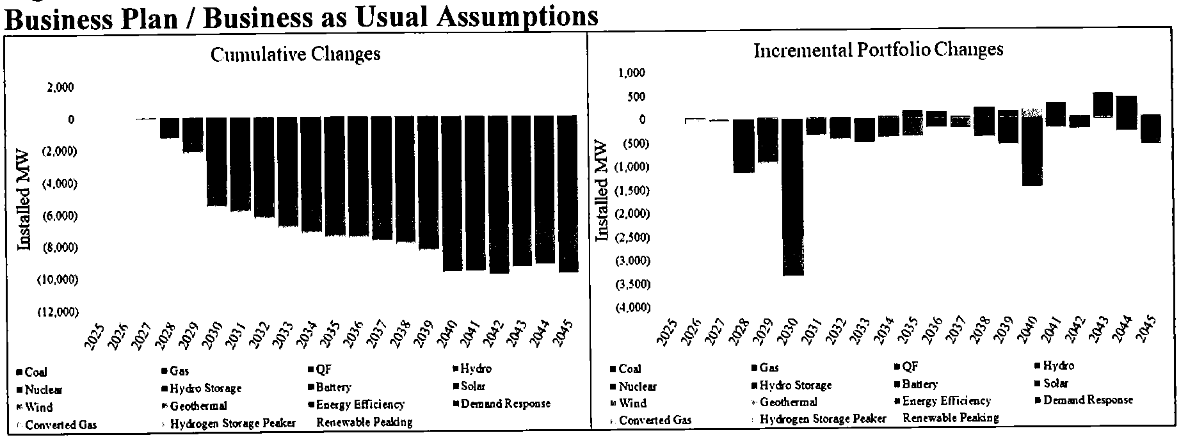


Business as Usual/Business Plan

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

[illegible]	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	**<u>Natrium™ Demonstration Project:</u>** • 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	**<u>Ozone Transport Rule Compliance:</u>** • 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	**<u>Natural Gas Emissions Compliance Strategies</u>** • 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	**<u>Federal Greenhouse Gas Emission Compliance:</u>** • 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	**<u>Dave Johnston Units 1 and 2:</u>** • 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	**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.

	4. Demand-Side Management (DSM) Actions
a	**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

[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.

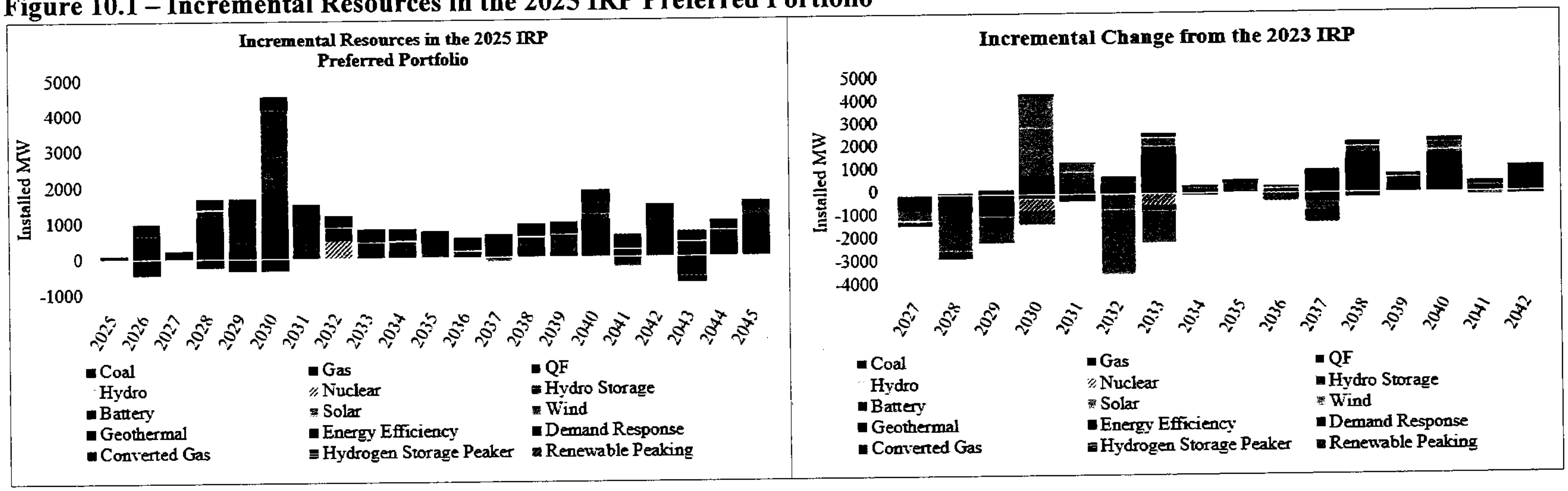
Action Item	6. Renewable Energy Credit (REC) Actions
6a	**Renewable Portfolio Standards (RPS):** • PacifiCorp may pursue unbundled REC RFPs and purchases to meet its state RPS compliance requirements. • PacifiCorp will issue RFPs seeking unbundled RECs that will qualify in meeting California RPS targets 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.

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	**Ozone Transport Rule Compliance:** • 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	**<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 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	**<u>2025 All-Source Request for Proposals:</u>** • 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	**Energy Gateway South Segment F (Aeolus-Clover 500 kV transmission line):** • 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	**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 in Q4 2024 •	The Energy Gateway West Sub-Segment D1 transmission project is in-service.
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.	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.

<table>
<tr><td></td><td>Continue negotiations for plan of service post B2H for parties to the permitting agreement.</td><td></td></tr>
<tr><td>3d</td><td>Initiate Local Reinforcement Projects as identified with the addition of new resources per the preferred portfolio, and follow-on requests for proposal successful bids</td><td>Reinforcements have been identified. A final assessment of upgrades is pending signed agreements.</td></tr>
<tr><td>3e</td><td>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.</td><td>PacifiCorp continues permitting efforts on both segments D.3 and E, maintaining the record of decision on each segment.</td></tr>
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<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.
<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></td><td>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.</td></tr>
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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.

[redacted]	
2023	72
2024	39
2025	152
2026	109

</td><td></td></tr>
<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.

</td></tr>
</table>

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

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

[illegible]	[illegible]	[illegible]	[illegible]
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.

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.

[illegible]	[illegible]	[illegible]	[illegible]
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.