# Utah 2025
## Integrated Resource Plan

Volume II - 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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# APPENDIX A – LOAD FORECAST

## Introduction

This appendix reviews the load forecast used in the modeling and analysis of the 2025 Integrated Resource Plan ("IRP"), including scenario development for case sensitivities. The load forecast used in the IRP is an estimate of the energy sales and peak demand over a 20-year period. The 20-year horizon is important to anticipate electricity demand to develop a timely response of resources.

In the development of its load forecast PacifiCorp employs econometric models that use historical data and inputs such as regional and national economic growth, weather, seasonality, and other customer usage and behavior changes. The forecast is divided into classes that use energy for similar purposes and at comparable retail rates. These separate customer classes include residential, commercial, industrial, irrigation, and lighting customer classes. The classes are modeled separately using variables specific to their usage patterns. For residential customers, typical energy uses include space heating, air conditioning, water heating, lighting, cooking, refrigeration, dish washing, laundry washing, televisions, and various other end-use appliances. Commercial and industrial customers use energy for production and manufacturing processes, space heating, air conditioning, lighting, computers, and other office equipment.

Jurisdictional peak load forecasts are developed using econometric equations that relate observed monthly peak loads, peak producing weather and the weather-sensitive loads for all classes. The system coincident peak forecast, which is used in portfolio development, is the maximum load required on the system in any hourly period and is extracted from the hourly forecast model.

### Summary Load Forecast

PacifiCorp updated its load forecast in May 2024. The primary driver to changes in PacifiCorp's 2025 IRP load forecast are due to the exclusion of specific new large customers who are expected to provide or pay for the resources and transmission necessary to support their load. These customers are expected to acquire their own resources; therefore, their loads have been excluded so that the PLEXOS capacity expansion optimization model does not plan Company resources to serve them.

The compound annual load growth rate for the 10-year period (2025 through 2034) is 1.28 percent. Relative to the load forecast prepared for the 2023 IRP, PacifiCorp's 2034 forecast load requirement decreased in all states other than Washington resulting in PacifiCorp system load requirement to decline 13.35 percent in 2034. Figure A.1 provides a comparison of the 2025 IRP and the 2023 IRP load forecasts.

**Figure A.1 – PacifiCorp System Load Forecast Change, at Generation, pre-DSM**

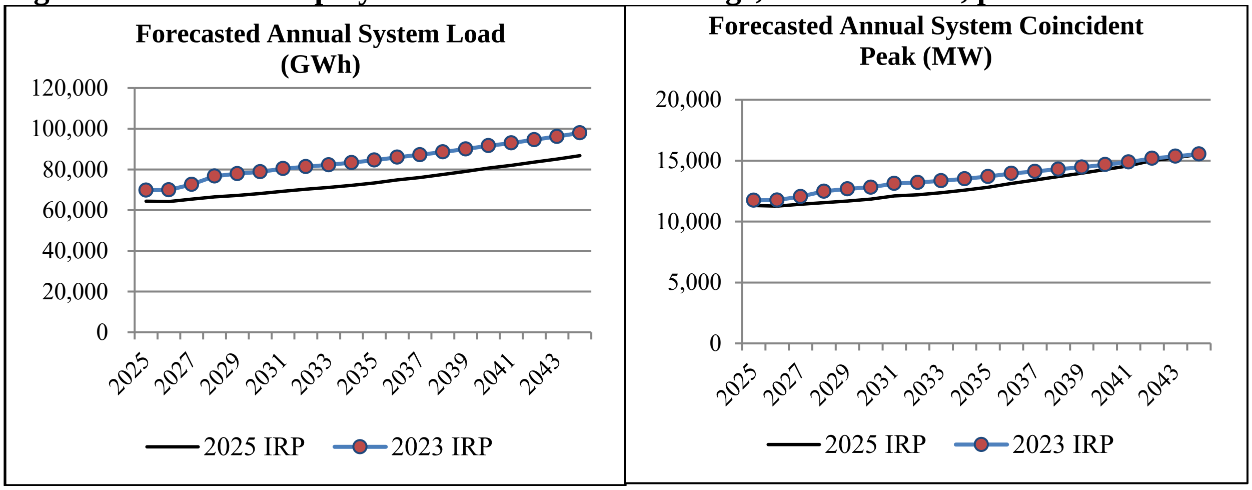



Table A.1 and Table A.2 show the annual load and coincident peak load forecast when not reducing load projections to account for new energy efficiency measures.[1] Table A.3 and Table A.4 show the forecast changes relative to the 2023 IRP load forecast for loads and coincident system peak, respectively.

**Table A.1 – Forecasted Annual Load, 2025 through 2034 (Megawatt-hours), at Generation, pre-DSM**

| Year | Total | OR | WA | CA | UT | WY | ID |
|---|---|---|---|---|---|---|---|
| **2025** | 64,414,790 | 16,114,060 | 4,545,410 | 844,170 | 29,396,700 | 9,662,750 | 3,851,700 |
| **2026** | 64,231,880 | 16,396,610 | 4,573,810 | 844,790 | 28,904,240 | 9,640,700 | 3,871,730 |
| **2027** | 65,395,390 | 16,601,790 | 4,761,850 | 844,380 | 29,627,340 | 9,666,940 | 3,893,090 |
| **2028** | 66,504,260 | 16,824,670 | 4,957,640 | 845,780 | 30,272,410 | 9,684,200 | 3,919,560 |
| **2029** | 67,262,990 | 16,995,130 | 4,967,740 | 842,310 | 30,839,670 | 9,686,200 | 3,931,940 |
| **2030** | 68,211,820 | 17,210,630 | 4,993,880 | 841,360 | 31,535,430 | 9,681,100 | 3,949,420 |
| **2031** | 69,249,310 | 17,432,090 | 5,018,660 | 840,620 | 32,295,080 | 9,696,570 | 3,966,290 |
| **2032** | 70,277,070 | 17,697,980 | 5,055,940 | 842,410 | 32,986,240 | 9,704,760 | 3,989,740 |
| **2033** | 71,146,810 | 17,911,130 | 5,071,770 | 839,820 | 33,621,250 | 9,700,290 | 4,002,550 |
| **2034** | 72,221,110 | 18,187,210 | 5,100,920 | 839,770 | 34,378,540 | 9,691,460 | 4,023,210 |
| **Compound Annual Growth Rate** | | | | | | | |
| **2025-34** | **1.28%** | **1.35%** | **1.29%** | **-0.06%** | **1.75%** | **0.03%** | **0.49%** |

[1] Energy efficiency load reductions are included as resources in the PLEXOS model.

**Table A.2 – Forecasted Annual Coincident Peak Load (Megawatts) at Generation, pre-DSM**

| Year | Total | OR | WA | CA | UT | WY | ID |
|---|---|---|---|---|---|---|---|
| **2025** | 11,318 | 2,752 | 830 | 146 | 5,597 | 1,233 | 760 |
| **2026** | 11,270 | 2,769 | 841 | 147 | 5,546 | 1,211 | 756 |
| **2027** | 11,425 | 2,803 | 880 | 147 | 5,631 | 1,211 | 753 |
| **2028** | 11,553 | 2,834 | 886 | 148 | 5,733 | 1,213 | 739 |
| **2029** | 11,690 | 2,869 | 891 | 148 | 5,829 | 1,214 | 739 |
| **2030** | 11,844 | 2,908 | 895 | 148 | 5,936 | 1,218 | 740 |
| **2031** | 12,104 | 3,011 | 898 | 148 | 6,058 | 1,220 | 769 |
| **2032** | 12,193 | 2,993 | 901 | 148 | 6,167 | 1,218 | 765 |
| **2033** | 12,363 | 3,072 | 933 | 152 | 6,229 | 1,208 | 770 |
| **2034** | 12,575 | 3,135 | 941 | 152 | 6,364 | 1,210 | 773 |
| **Compound Annual Growth Rate** | | | | | | | |
| **2025-34** | **1.18%** | **1.46%** | **1.40%** | **0.44%** | **1.44%** | **-0.21%** | **0.18%** |

**Table A.3 – Annual Load Change: May 2024 Forecast less May 2022 Forecast (Megawatt-hours) at Generation, pre-DSM**

| Year | Total | OR | WA | CA | UT | WY | ID |
|---|---|---|---|---|---|---|---|
| **2025** | (5,390,270) | (3,616,260) | (155,350) | (11,050) | (964,520) | (412,110) | (230,980) |
| **2026** | (5,706,540) | (4,061,040) | (147,950) | (8,180) | (783,240) | (472,540) | (233,590) |
| **2027** | (7,254,380) | (5,159,500) | 5,020 | (8,800) | (1,407,080) | (450,000) | (234,020) |
| **2028** | (10,176,860) | (6,621,290) | 146,440 | (10,700) | (2,911,330) | (544,910) | (235,070) |
| **2029** | (10,656,290) | (6,957,650) | 126,430 | (12,850) | (3,021,690) | (553,770) | (236,760) |
| **2030** | (10,600,020) | (6,855,430) | 108,530 | (14,430) | (2,948,470) | (651,450) | (238,770) |
| **2031** | (11,131,380) | (7,389,600) | 87,960 | (15,980) | (2,904,810) | (667,550) | (241,400) |
| **2032** | (11,044,710) | (7,462,900) | 65,540 | (17,550) | (2,614,110) | (771,970) | (243,720) |
| **2033** | (11,075,420) | (7,508,650) | 45,520 | (18,880) | (2,540,700) | (807,980) | (244,730) |
| **2034** | (11,130,430) | (7,554,380) | 23,940 | (20,350) | (2,466,790) | (868,020) | (244,830) |

**Table A.4 – Annual Coincident Peak Change: May 2024 Forecast less May 2022 Forecast (Megawatts) at Generation, pre-DSM**

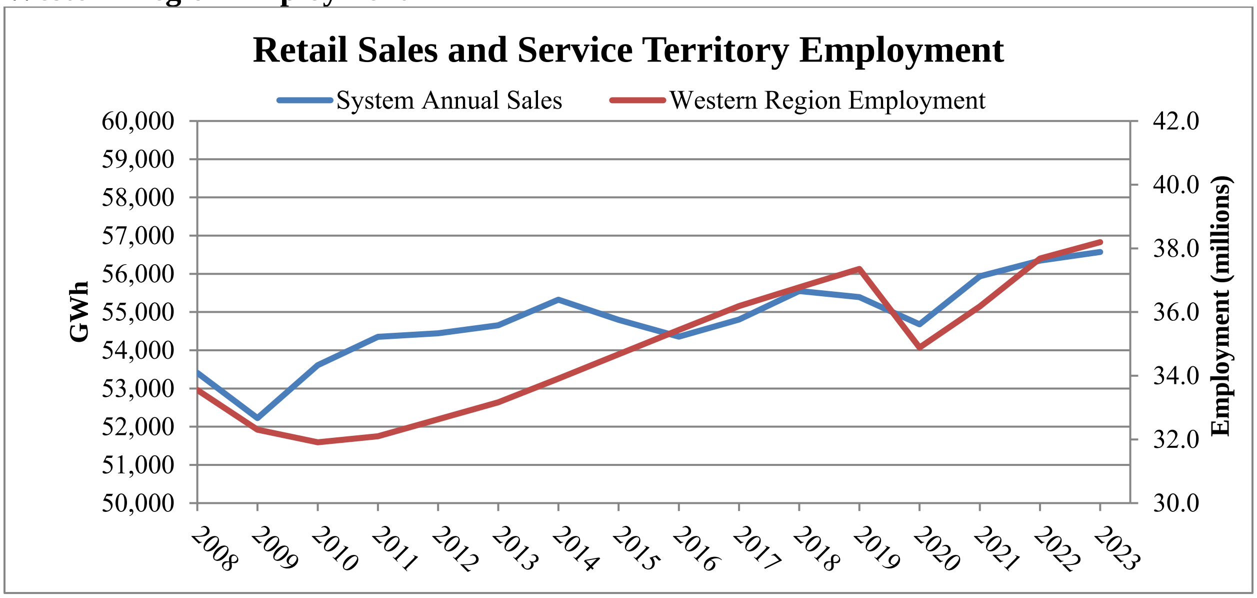
| Year | Total | OR | WA | CA | UT | WY | ID |
|---|---|---|---|---|---|---|---|
| **2025** | (429) | (259) | (26) | (1) | (31) | (68) | (43) |
| **2026** | (488) | (284) | (30) | (1) | (27) | (94) | (52) |
| **2027** | (626) | (386) | (7) | (2) | (76) | (95) | (60) |
| **2028** | (931) | (489) | (19) | (4) | (260) | (105) | (55) |
| **2029** | (992) | (618) | (36) | (9) | (194) | (77) | (59) |
| **2030** | (971) | (599) | (51) | (10) | (165) | (83) | (63) |
| **2031** | (1,019) | (620) | (68) | (12) | (156) | (91) | (72) |
| **2032** | (1,016) | (639) | (84) | (13) | (101) | (97) | (82) |
| **2033** | (984) | (599) | (73) | (10) | (128) | (115) | (60) |
| **2034** | (937) | (575) | (85) | (11) | (83) | (121) | (62) |

# Load Forecast Assumptions

## Regional Economy by Jurisdiction

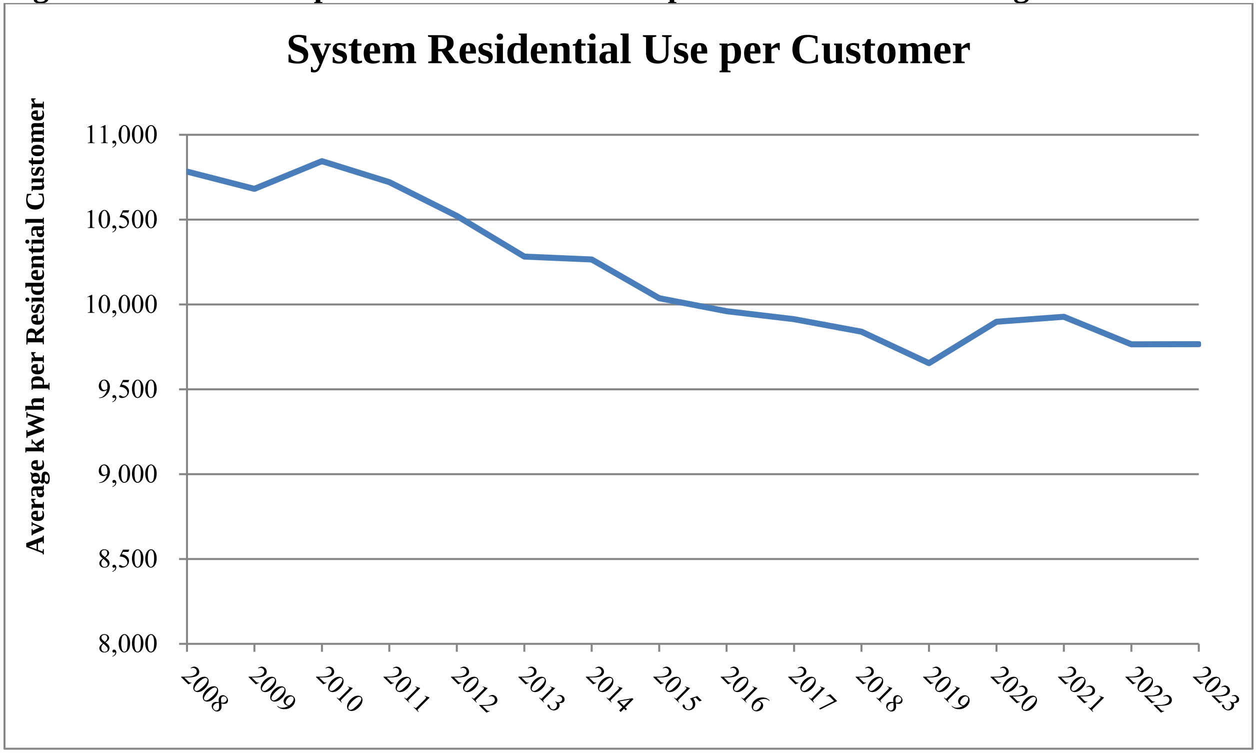
The PacifiCorp electric service territory is comprised of six states and within these states the Company serves customers in a total of 90 counties. The level of retail sales for each state and county is correlated with economic conditions and population statistics in each state. PacifiCorp uses both economic data, such as employment, and population data, to forecast its retail sales. Looking at historical sales and employment data for PacifiCorp's service territory, 2008 through 2023, in Figure A.2, it is apparent that PacifiCorp's retail sales are correlated to economic conditions in its service territory, and most recently the economic downturn and rebound from the COVID-19 pandemic.

**Figure A.2 – PacifiCorp Annual Retail Sales 2008 through 2023 and Western Region Employment**




The 2025 IRP forecast utilizes the February 2024 release of S&P Global Market Intelligence (formerly known as IHS Markit) economic driver forecast, whereas the 2023 IRP relied on the March 2022 release from S&P Global Market Intelligence. Figure A.3 shows the weather normalized average system residential use per customer.

**Figure A.3 – PacifiCorp Annual Residential Use per Customer 2008 through 2023**




## Weather

PacifiCorp'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.

The climate change weather target temperature relies on actual 1990 average temperatures and projected temperature increases over 1990 average temperatures as determined by the United States Bureau of Reclamation (Reclamation) in the West-Wide Climate Risk Assessments: Hydroclimate Projections Study (Study).[2] PacifiCorp determined daily average temperatures and peak producing temperatures that correspond to the midpoint of the projected temperature increase between the Representative Concentration Pathway (RCP) 4.5 and RCP 8.5 ranges in the Study.

[2] United States Bureau of Reclamation, March 2021, Managing Water in the West, Technical Memorandum No. ENV-2021-001, West-Wide Climate Risk Assessments: Hydroclimate Projections. https://www.usbr.gov/climate/secure/docs/2021secure/westwidesecurereport1-2.pdf

**Table A.5 – Projected Range of Temperature Change in the 2020s and 2050s relative to the 1990s**[3]

| Bureau of Reclamation Site | PacifiCorp Jurisdiction Assumption | Projected Range of Temperature Change (°F)* | |
|---|---|---|---|
| | | 2020s | 2050s |
| Klamath River near Klamath | California | 1.7 to 2.6 | 3.6 to 5.2 |
| Snake River Near Heise | Idaho | 1.6 to 3.0 | 4.1 to 5.9 |
| Klamath River near Seiad Valley | Oregon | 1.8 to 2.7 | 3.7 to 5.3 |
| Green River near Greendale | Utah | 1.8 to 3.3 | 4.2 to 6.3 |
| Yakima River at Parker | Washington | 1.8 to 2.8 | 3.6 to 5.6 |
| Green River near Greendale | Wyoming | 1.8 to 3.3 | 4.2 to 6.3 |

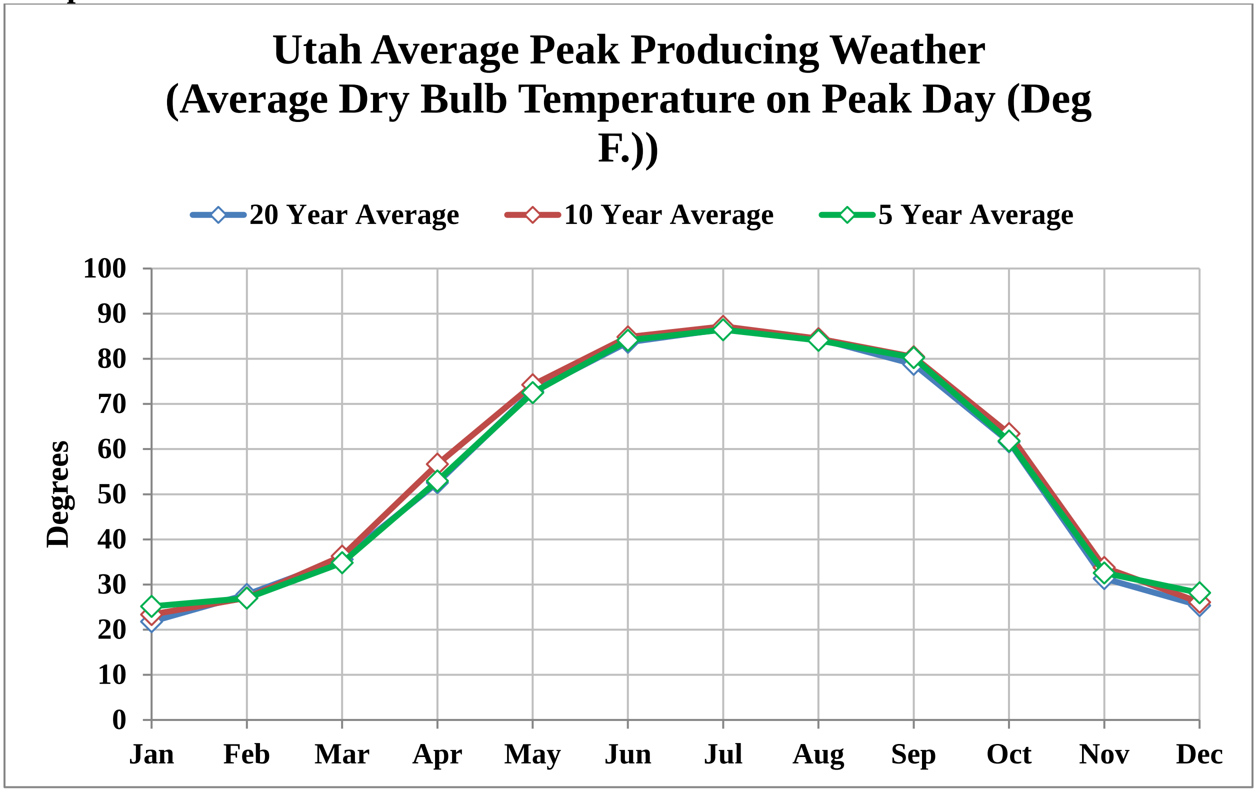
*Lower bound of temperature projections based on RCP 4.5, while upper bound based on RCP 8.5

In addition to climate change weather discussed above, PacifiCorp has reviewed the appropriateness of using the average weather from a shorter time period as its “normal” peak weather. Figure A.4 indicates that peak producing weather does not change significantly when comparing five, 10, or 20-year average weather.

PacifiCorp also updated its temperature spline models to the five-year time period of October 2018 – September 2023. PacifiCorp’s spline models are used to model the commercial, residential and irrigation class temperature sensitivity at varying temperatures.

[3] Ibid.

**Figure A.4 – Comparison of Utah 5, 10, and 20-Year Average Peak Producing Temperatures**




## Statistically Adjusted End-Use ("SAE")

PacifiCorp models sales per customer for the residential class using the SAE model, which combines the end-use modeling concepts with traditional regression analysis techniques. Major drivers of the SAE-based residential model are heating and cooling related variables, equipment shares, saturation levels and efficiency trends, and economic drivers such as household size, income, and energy price. PacifiCorp uses ITRON for its load forecasting software and services, as well as the SAE. To predict future changes in the efficiency of the various end uses for the residential class, an Excel spreadsheet model obtained from ITRON was utilized; the model includes appliance efficiency trends based on appliance life as well as past and future efficiency standards. The model embeds all currently applicable laws and regulations regarding appliance efficiency, along with life cycle models of each appliance. The life cycle models, based on the decay and replacement rate are necessary to estimate how fast the existing stock of any given appliance turns over, i.e., newer more efficient equipment replacing older less efficient equipment. The underlying efficiency data is based on estimates of energy efficiency from the US Department of Energy's Energy Information Administration (EIA). The EIA estimates the efficiency of appliance stocks and the saturation of appliances at the national level and for individual Census Regions.

## Individual Customer Forecast

PacifiCorp updated its load forecast for a select group of large industrial customers, self-generation facilities of large industrial customers, and commercial data center forecasts within the respective jurisdictions.

Customer forecasts are provided by the customer to PacifiCorp through a regional business manager ("RBM").

## Actual Load Data

With the exception to the industrial and the street lighting classes, PacifiCorp uses actual load data from January 2006 through February 2024. The historical data period used to develop the industrial monthly sales forecast is from January 2006 through February 2024 in California, Idaho, Utah, Washington and Wyoming. January 2008 through February 2024 is used in Oregon. The historical data period used to develop the street light monthly sales forecast for Oregon is from April 2006 through February 2024 and for Utah it is January 2007 through February 2024.

**Table A.6 – Weather Normalized Jurisdictional Retail Sales 2008 through 2023**

| System Retail Sales - Megawatt-hours (MWh)* | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Year** | California | Idaho | Oregon | Utah | Washington | Wyoming | **System** |
| **2008** | 858,950 | 3,447,815 | 13,143,154 | 22,725,958 | 4,066,187 | 9,166,786 | **53,408,850** |
| **2009** | 821,496 | 2,990,395 | 12,992,344 | 22,160,113 | 4,035,869 | 9,224,533 | **52,224,750** |
| **2010** | 835,316 | 3,482,028 | 13,049,455 | 22,581,496 | 4,036,261 | 9,623,480 | **53,608,035** |
| **2011** | 798,656 | 3,495,853 | 12,883,008 | 23,392,972 | 4,008,345 | 9,771,921 | **54,350,755** |
| **2012** | 778,337 | 3,544,362 | 12,914,227 | 23,731,702 | 4,027,750 | 9,448,692 | **54,445,070** |
| **2013** | 767,445 | 3,573,026 | 12,960,411 | 23,799,941 | 4,038,910 | 9,514,315 | **54,654,048** |
| **2014** | 764,480 | 3,581,617 | 13,062,897 | 24,272,779 | 4,080,862 | 9,562,888 | **55,325,523** |
| **2015** | 734,199 | 3,542,141 | 13,060,948 | 24,045,657 | 4,063,695 | 9,349,334 | **54,795,974** |
| **2016** | 746,449 | 3,503,137 | 13,205,242 | 23,696,002 | 4,014,408 | 9,190,762 | **54,356,000** |
| **2017** | 750,570 | 3,596,265 | 13,229,888 | 23,837,915 | 4,056,911 | 9,331,995 | **54,803,545** |
| **2018** | 734,567 | 3,654,789 | 13,252,578 | 24,627,024 | 4,038,845 | 9,243,048 | **55,550,852** |
| **2019** | 737,603 | 3,529,552 | 13,226,821 | 24,542,645 | 4,036,076 | 9,318,836 | **55,391,533** |
| **2020** | 757,481 | 3,599,853 | 13,179,461 | 24,742,370 | 4,081,180 | 8,317,875 | **54,678,220** |
| **2021** | 788,621 | 3,524,419 | 13,705,078 | 25,309,780 | 4,114,232 | 8,494,548 | **55,936,679** |
| **2022** | 785,410 | 3,661,104 | 13,715,836 | 25,455,539 | 4,023,511 | 8,705,156 | **56,346,557** |
| **2023** | 755,275 | 3,573,339 | 13,988,996 | 25,712,395 | 3,823,307 | 8,718,426 | **56,571,738** |
| **Compound Annual Growth Rate** | | | | | | | |
| **2008-23** | **-0.85%** | **0.24%** | **0.42%** | **0.83%** | **-0.41%** | **-0.33%** | **0.38%** |

*System retail sales do not include sales for resale

**Table A.7 – Non-Coincident Jurisdictional Peak 2008 through 2023**

| Non-Coincident Peak - Megawatts (MW)* | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Year** | California | Idaho | Oregon | Utah | Washington | Wyoming | **System** |
| **2008** | 187 | 759 | 2,921 | 4,479 | 923 | 1,339 | **10,609** |
| **2009** | 193 | 688 | 3,121 | 4,404 | 917 | 1,383 | **10,705** |
| **2010** | 176 | 777 | 2,552 | 4,448 | 893 | 1,366 | **10,213** |
| **2011** | 177 | 770 | 2,686 | 4,596 | 854 | 1,404 | **10,486** |
| **2012** | 159 | 800 | 2,550 | 4,732 | 797 | 1,337 | **10,376** |
| **2013** | 182 | 814 | 2,980 | 5,091 | 886 | 1,398 | **11,351** |
| **2014** | 161 | 818 | 2,598 | 5,024 | 871 | 1,360 | **10,831** |
| **2015** | 157 | 843 | 2,598 | 5,226 | 837 | 1,326 | **10,986** |
| **2016** | 155 | 848 | 2,584 | 5,018 | 819 | 1,300 | **10,724** |
| **2017** | 177 | 830 | 2,920 | 4,932 | 943 | 1,354 | **11,156** |
| **2018** | 158 | 830 | 2,608 | 5,091 | 849 | 1,319 | **10,854** |
| **2019** | 151 | 793 | 2,632 | 5,158 | 895 | 1,363 | **10,993** |
| **2020** | 155 | 806 | 2,562 | 5,336 | 848 | 1,271 | **10,979** |
| **2021** | 149 | 771 | 2,894 | 5,547 | 938 | 1,299 | **11,598** |
| **2022** | 162 | 833 | 2,813 | 5,526 | 895 | 1,314 | **11,543** |
| **2023** | 155 | 769 | 2,924 | 5,431 | 844 | 1,324 | **11,447** |
| **Compound Annual Growth Rate** | | | | | | | |
| **2008-23** | **-1.24%** | **0.08%** | **0.01%** | **1.29%** | **-0.59%** | **-0.08%** | **0.51%** |

*Non-coincident peaks do not include sales for resale

**Table A.8 – Jurisdictional Contribution to Coincident Peak 2008 through 2023**

| Coincident Peak - Megawatts (MW)* | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Year** | California | Idaho | Oregon | Utah | Washington | Wyoming | **System** |
| **2008** | 171 | 682 | 2,521 | 4,145 | 728 | 1,208 | **9,456** |
| **2009** | 153 | 517 | 2,573 | 4,351 | 795 | 987 | **9,375** |
| **2010** | 144 | 527 | 2,442 | 4,294 | 757 | 1,208 | **9,373** |
| **2011** | 143 | 549 | 2,187 | 4,596 | 707 | 1,204 | **9,387** |
| **2012** | 156 | 782 | 2,163 | 4,731 | 749 | 1,225 | **9,806** |
| **2013** | 156 | 674 | 2,407 | 5,091 | 797 | 1,349 | **10,474** |
| **2014** | 150 | 630 | 2,345 | 5,024 | 819 | 1,294 | **10,263** |
| **2015** | 152 | 805 | 2,472 | 5,081 | 833 | 1,259 | **10,601** |
| **2016** | 139 | 575 | 2,462 | 4,940 | 817 | 1,201 | **10,135** |
| **2017** | 152 | 593 | 2,547 | 4,911 | 787 | 1,306 | **10,296** |
| **2018** | 126 | 741 | 2,526 | 5,037 | 790 | 1,295 | **10,514** |
| **2019** | 122 | 731 | 2,276 | 5,158 | 761 | 1,248 | **10,297** |
| **2020** | 127 | 603 | 2,428 | 5,336 | 839 | 1,180 | **10,515** |
| **2021** | 145 | 767 | 2,543 | 5,319 | 839 | 1,214 | **10,827** |
| **2022** | 142 | 730 | 2,726 | 5,250 | 870 | 1,266 | **10,984** |
| **2023** | 140 | 509 | 2,890 | 5,196 | 807 | 1,223 | **10,765** |
| **Compound Annual Growth Rate** | | | | | | | |
| **2008-23** | **-1.33%** | **-1.93%** | **0.92%** | **1.52%** | **0.69%** | **0.08%** | **0.87%** |

*Coincident peaks do not include sales for resale

## System Losses

Line loss factors are derived using the five-year average of the percent difference between the annual system load by jurisdiction and the retail sales by jurisdiction. System line losses were updated to reflect actual losses for the five-year period ending December 31, 2023.

# Forecast Methodology Overview

## Demand-side Management Resources in the Load Forecast

PacifiCorp models demand-side management (DSM) as a resource option to be selected as part of a cost-effective portfolio resource mix using the PLEXOS capacity expansion optimization model. The load forecast used for IRP portfolio development excluded forecasted load reductions from energy efficiency; PLEXOS then determines the amount of energy efficiency—expressed as supply curves that relate incremental DSM quantities with their costs—given the other resource options and inputs included in the model. The use of energy efficiency supply curves, along with the economic screening provided by PLEXOS, determines the cost-effective mix of energy efficiency for a given scenario.

## Modeling overview

The load forecast is developed by forecasting the monthly sales by customer class for each jurisdiction. The residential sales forecast is developed as a use-per-customer forecast multiplied by the forecasted number of customers.

The customer forecasts are based on a combination of regression analysis and exponential smoothing techniques using historical data from January 2006 to February 2024. For the residential class, PacifiCorp forecasts the number of customers using S&P Global Market Intelligence forecast of each state's population or number of households as the major driver.

PacifiCorp uses a differenced model approach in the development of the residential customer forecast. Rather than directly forecasting the number of customers, the differenced model predicts the monthly change in number of customers.

PacifiCorp models sales per customer for the residential class using the SAE model discussed above, which combines the end-use modeling concepts with traditional regression analysis techniques.

For the commercial class, PacifiCorp forecasts sales using regression analysis techniques with non-manufacturing employment and non-farm employment designated as the major economic drivers, in addition to weather-related variables. Monthly sales for the commercial class are forecast directly from historical sales volumes, not as a product of the use per customer and number of customers. The development of the forecast of monthly commercial sales involves an additional step; to reflect the addition of a large "lumpy" change in sales such as a new data center, monthly commercial sales are increased based on input from PacifiCorp's RBM's. The treatment of large commercial additions is like the methodology for large industrial customer sales, which is discussed below.

Monthly sales for irrigation and street lighting are forecast directly from historical sales volumes, not as a product of the use per customer and number of customers.

Many industrial sales are modeled using regression analysis with trend and economic variables. Manufacturing employment is used as the major economic driver in all states with exception of Utah and West Wyoming, in which an Industrial Production Index and mining employment, respectively, is used. For a small number of the very largest industrial customers, PacifiCorp prepares individual forecasts based on input from the customer and information provided by the RBM's.

After PacifiCorp develops the forecasts of monthly energy sales by customer class, a forecast of hourly loads is developed in two steps. First, monthly peak forecasts are developed for each state. The monthly peak model uses historical peak-producing weather for each state and incorporates the impact of weather on load above baseload through several weather variables that drive heating and cooling usage. The weather variables include the average temperature on the peak day and lagged average temperatures from up to two days before the day of the forecast. The peak forecast is based on the climate change peak-producing weather discussed above.

Second, PacifiCorp develops hourly load forecasts for each state using hourly load models that include state-specific hourly load data, daily weather variables, the 20-year average temperatures for the 20-year period 2004 through 2023, a typical annual weather pattern, and day-type variables such as weekends and holidays as inputs to the model. The hourly loads are adjusted to match the monthly peaks from the first step above. Hourly loads are then adjusted so the monthly sum of hourly loads equals monthly sales plus line losses.

After the hourly load forecasts are developed for each state, hourly loads are aggregated to the total system level. The system coincident peaks can then be identified, as well as the contribution of each jurisdiction to those monthly peaks.

## Electrification Adjustments

The load forecast used for 2025 IRP portfolio development includes PacifiCorp's expectations for transportation electrification based on current and expected electric-vehicle (EV) adoption trends. These projections were incorporated as a post-model adjustment to the residential and commercial sales forecasts.

Electric vehicle adoption and load impacts vary by state depending on a variety of socioeconomic factors and policies particular to each state. To develop a prospective forecast of EV adoption, PacifiCorp developed a model to assess trends for light-duty EVs and medium-duty EVs. To develop a future EV adoption curve, PacifiCorp reviewed three national EV forecasts, each representing varying degrees of aggressiveness. While these forecasts represent national trends, the adoption curves themselves can be applied and adapted to state-specific parameters to reflect current market conditions in the state. PacifiCorp calibrates each adoption curve source to base inputs from EIA's Annual Energy Outlook (AEO) projections and estimated historical vehicle actuals. The AEO inputs include estimated shares of battery electric vehicles and plug-in hybrid electric vehicles as well as light-duty vehicles and light-duty trucks. Each of the national adoption curve sources is discussed below to help contextualize the various sources reviewed for this plan's EV adoption forecast.[4]

2025 IRP is based on a specific EV shape for EV loads. Historically, EV loads were added to jurisdictional loads and shaped based on jurisdictional load shape. While electric vehicle loads were small, this approach generated satisfactory results, but with growth drivers such as state and federal mandates and the Inflation Reduction Act of 2022, EV loads have an increasing potential

[4] Transportation electrification impacts for Oregon and Washington may differ slightly from estimated impacts provided in transportation electrification plans as result of the vintage associated with data inputs.

impact on loads and peaks. It is important that this growing impact on loads be modeled correctly both so that PacifiCorp can plan for the load effectively and so that programs to mitigate for this growth, such as time-of-use (TOU) rates can be introduced and their benefits correctly quantified.

The load forecast also incorporates PacifiCorp's expectations for building electrification initiatives. In the near-term, building electrification is relatively minor share of load but is expected to grow over time as state and national policies encouraging fuel substitution and electrification become more prevalent. PacifiCorp's building electrification forecast is based on expected fuel shares for space heating and water heating equipment at the end of its useful life and future new construction shares of electric fuel for these end-uses over time. Adoption curves are calibrated to expected equipment turnover and new construction rates in alignment with assumptions used in the Conservation Potential Assessment. Adoption curves and timing of building electrification is estimated based on the state specific policies or known market trends supporting advancement of building electrification.

PacifiCorp continually assesses both transportation and building electrification market trends, policies, and adoptions levels in each state. As these markets evolve, PacifiCorp will continue to update forecasts to reflect new trends as they occur.

## Private Generation

The 2025 IRP load forecast relies on private generation adoption expectations as determined by third-party vendor, DNV. The Distributed Generation Forecast Behind-the-Meter Resource Assessment was developed by DNV for Utah, Oregon, Idaho, Wyoming, California, and Washington. The study evaluated the expected adoption of behind-the-meter (BTM) technologies including photovoltaic solar, photovoltaic solar coupled with battery storage, small scale wind, small scale hydro, reciprocating engines, and microturbines for a 20-year forecast horizon. The study provided projections for three cases, which includes the base, high, and low adoption projections.

Please refer to Appendix L – Distributed Generation Study for additional information regarding the methodology and assumptions used to develop the Distributed Generation Forecast Behind-the-Meter Resource Assessment.

# Sales Forecast at the Customer Meter

This section provides total system and state-level forecasted retail sales summaries measured at the customer meter by customer class including load reduction projections from new energy efficiency measures from the Preferred Portfolio.

**Table A.9 – System Annual Retail Sales Forecast 2025 through 2034, post-DSM**

| System Retail Sales – Megawatt-hours (MWh) | | | | | | |
|---|---|---|---|---|---|---|
| **Year** | Residential | Commercial | Industrial | Irrigation | Lighting | **Total** |
| **2025** | 18,192,073 | 21,909,908 | 17,371,196 | 1,435,667 | 100,845 | **59,009,688** |
| **2026** | 18,478,238 | 22,063,280 | 16,214,788 | 1,431,485 | 99,108 | **58,286,900** |
| **2027** | 18,800,131 | 22,197,849 | 16,450,828 | 1,423,054 | 97,668 | **58,969,530** |

| | | | | | | |
|---|---|---|---|---|---|---|
| **2028** | 19,190,567 | 22,091,187 | 16,738,021 | 1,413,274 | 96,623 | **59,529,672** |
| **2029** | 19,491,361 | 21,871,170 | 16,772,389 | 1,401,328 | 95,019 | **59,631,266** |
| **2030** | 19,875,324 | 21,698,175 | 16,845,920 | 1,389,305 | 93,664 | **59,902,389** |
| **2031** | 20,306,301 | 21,596,410 | 16,980,838 | 1,378,814 | 92,340 | **60,354,704** |
| **2032** | 20,772,055 | 21,432,263 | 16,902,580 | 1,365,336 | 91,412 | **60,563,647** |
| **2033** | 21,157,523 | 21,190,484 | 16,787,515 | 1,350,595 | 90,171 | **60,576,289** |
| **2034** | 21,622,660 | 21,050,123 | 16,673,196 | 1,338,528 | 89,435 | **60,773,943** |
| **Compound Annual Growth Rate** | | | | | | |
| **2025-34** | **1.94%** | **-0.44%** | **-0.45%** | **-0.78%** | **-1.33%** | **0.33%** |

## State Summaries

### Oregon

Table A.10 summarizes Oregon state forecasted retail sales growth by customer class. Growth in Oregon retail sales are driven by expectations for the residential class.

**Table A.10 – Forecasted Retail Sales Growth in Oregon, post-DSM**

| **Oregon Retail Sales – Megawatt-hours (MWh)** | | | | | | |
|---|---|---|---|---|---|---|
| **Year** | Residential | Commercial | Industrial | Irrigation | Lighting | **Total** |
| **2025** | 5,952,780 | 6,715,632 | 1,367,320 | 250,920 | 30,121 | **14,316,773** |
| **2026** | 6,010,181 | 6,758,288 | 1,371,878 | 250,815 | 29,642 | **14,420,803** |
| **2027** | 6,051,304 | 6,729,400 | 1,341,400 | 250,332 | 29,255 | **14,401,692** |
| **2028** | 6,108,184 | 6,691,531 | 1,319,069 | 249,914 | 29,049 | **14,397,746** |
| **2029** | 6,135,339 | 6,638,809 | 1,290,269 | 249,222 | 28,749 | **14,342,388** |
| **2030** | 6,193,330 | 6,589,995 | 1,270,861 | 248,611 | 28,592 | **14,331,390** |
| **2031** | 6,252,656 | 6,543,338 | 1,251,491 | 247,971 | 28,479 | **14,323,935** |
| **2032** | 6,336,181 | 6,509,261 | 1,225,849 | 247,033 | 28,480 | **14,346,805** |
| **2033** | 6,412,705 | 6,464,445 | 1,194,298 | 245,438 | 28,340 | **14,345,226** |
| **2034** | 6,528,806 | 6,446,045 | 1,161,233 | 244,342 | 28,298 | **14,408,725** |
| **Compound Annual Growth Rate** | | | | | | |
| **2025-34** | **1.03%** | **-0.45%** | **-1.80%** | **-0.29%** | **-0.69%** | **0.07%** |

### Washington

Table A.11 summarizes Washington state forecasted retail sales growth by customer class. Growth in Washington retail sales are driven by expectations for the industrial class.

| Table A.11 – Forecasted Retail Sales Growth in Washington, post-DSM **Washington Retail Sales – Megawatt-hours (MWh)** | | | | | | |
|---|---|---|---|---|---|---|
| **Year** | Residential | Commercial | Industrial | Irrigation | Lighting | **Total** |
| **2025** | 1,617,779 | 1,529,202 | 724,050 | 157,018 | 3,978 | **4,032,026** |

| | | | | | | |
|---|---|---|---|---|---|---|
| **2026** | 1,626,189 | 1,530,187 | 711,068 | 156,285 | 3,985 | **4,027,715** |
| **2027** | 1,626,300 | 1,529,021 | 849,486 | 155,619 | 3,985 | **4,164,411** |
| **2028** | 1,624,874 | 1,527,690 | 989,969 | 154,616 | 3,997 | **4,301,146** |
| **2029** | 1,611,783 | 1,516,912 | 985,982 | 153,651 | 3,985 | **4,272,314** |
| **2030** | 1,604,064 | 1,509,197 | 985,768 | 152,587 | 3,985 | **4,255,601** |
| **2031** | 1,597,678 | 1,502,852 | 984,776 | 151,790 | 3,985 | **4,241,082** |
| **2032** | 1,592,476 | 1,494,420 | 981,491 | 150,169 | 3,997 | **4,222,553** |
| **2033** | 1,580,259 | 1,477,848 | 972,546 | 148,565 | 3,985 | **4,183,203** |
| **2034** | 1,574,975 | 1,467,106 | 964,432 | 147,149 | 3,985 | **4,157,648** |
| **Compound Annual Growth Rate** | | | | | | |
| **2025-34** | **-0.30%** | **-0.46%** | **3.24%** | **-0.72%** | **0.02%** | **0.34%** |

## California

Table A.12 summarizes California state forecasted sales growth by customer class. Decrease in California retail sales are driven by expectations for the commercial class.

**Table A.12 - Forecasted Retail Sales Growth in California, post-DSM**

| **California Retail Sales – Megawatt-hours (MWh)** | | | | | | |
|---|---|---|---|---|---|---|
| **Year** | Residential | Commercial | Industrial | Irrigation | Lighting | **Total** |
| **2025** | 378,690 | 236,019 | 52,824 | 91,016 | 1,664 | **760,212** |
| **2026** | 379,100 | 233,017 | 52,181 | 91,302 | 1,649 | **757,249** |
| **2027** | 378,764 | 230,241 | 51,589 | 90,842 | 1,639 | **753,075** |
| **2028** | 379,366 | 228,367 | 51,192 | 90,209 | 1,636 | **750,769** |
| **2029** | 377,307 | 225,092 | 50,631 | 89,407 | 1,625 | **744,062** |
| **2030** | 376,535 | 222,645 | 50,296 | 88,589 | 1,621 | **739,686** |
| **2031** | 375,811 | 220,270 | 49,978 | 87,753 | 1,618 | **735,430** |
| **2032** | 376,378 | 218,509 | 49,758 | 86,776 | 1,621 | **733,042** |
| **2033** | 374,716 | 214,981 | 49,210 | 85,561 | 1,615 | **726,082** |
| **2034** | 374,457 | 212,245 | 48,841 | 84,488 | 1,613 | **721,644** |
| **Compound Annual Growth Rate** | | | | | | |
| **2025-34** | **-0.12%** | **-1.17%** | **-0.87%** | **-0.82%** | **-0.34%** | **-0.58%** |

## Utah

Table A.13 summarizes Utah state forecasted sales growth by customer class. Growth in Utah retail sales are driven by expectations for the residential class.

**Table A.13 – Forecasted Retail Sales Growth in Utah, post-DSM**

| Utah Retail Sales – Megawatt-hours (MWh) | | | | | | |
|---|---|---|---|---|---|---|
| **Year** | Residential | Commercial | Industrial | Irrigation | Lighting | **Total** |
| **2025** | 8,376,501 | 11,476,530 | 7,286,541 | 236,606 | 50,688 | **27,426,867** |
| **2026** | 8,594,571 | 11,601,196 | 6,192,020 | 233,425 | 49,770 | **26,670,982** |
| **2027** | 8,874,055 | 11,787,852 | 6,332,359 | 229,689 | 49,224 | **27,273,180** |
| **2028** | 9,204,255 | 11,741,914 | 6,525,760 | 225,303 | 49,038 | **27,746,270** |
| **2029** | 9,506,156 | 11,621,980 | 6,609,541 | 220,255 | 48,708 | **28,006,641** |
| **2030** | 9,849,880 | 11,532,865 | 6,729,616 | 214,774 | 48,597 | **28,375,731** |
| **2031** | 10,237,731 | 11,508,017 | 6,890,399 | 210,111 | 48,532 | **28,894,792** |
| **2032** | 10,629,198 | 11,412,798 | 6,871,721 | 203,493 | 48,632 | **29,165,842** |
| **2033** | 10,968,166 | 11,270,916 | 6,831,483 | 196,715 | 48,473 | **29,315,754** |
| **2034** | 11,330,944 | 11,189,384 | 6,805,015 | 190,863 | 48,461 | **29,564,668** |
| **Compound Annual Growth Rate** | | | | | | |
| **2025-34** | **3.41%** | **-0.28%** | **-0.76%** | **-2.36%** | **-0.50%** | **0.84%** |

## Idaho

Table A.14 summarizes Idaho state forecasted sales growth by customer class. Decrease in Idaho retail sales are driven by expectations for the commercial class.

**Table A.14 - Forecasted Retail Sales Growth in Idaho, post-DSM**

| Idaho Retail Sales – Megawatt-hours (MWh) | | | | | | |
|---|---|---|---|---|---|---|
| **Year** | Residential | Commercial | Industrial | Irrigation | Lighting | **Total** |
| **2025** | 811,032 | 557,096 | 1,587,100 | 669,538 | 2,639 | **3,627,405** |
| **2026** | 815,973 | 551,568 | 1,583,461 | 669,118 | 2,584 | **3,622,705** |
| **2027** | 822,198 | 549,212 | 1,581,458 | 666,172 | 2,502 | **3,621,543** |
| **2028** | 829,646 | 547,613 | 1,580,474 | 662,984 | 2,394 | **3,623,112** |
| **2029** | 829,200 | 541,094 | 1,578,348 | 658,733 | 2,236 | **3,609,612** |
| **2030** | 830,437 | 535,557 | 1,577,652 | 654,831 | 2,058 | **3,600,534** |
| **2031** | 831,025 | 528,787 | 1,576,746 | 651,325 | 1,869 | **3,589,752** |
| **2032** | 834,627 | 522,879 | 1,575,943 | 648,136 | 1,698 | **3,583,284** |
| **2033** | 832,920 | 514,181 | 1,572,933 | 644,763 | 1,545 | **3,566,342** |
| **2034** | 835,354 | 508,041 | 1,570,309 | 642,274 | 1,433 | **3,557,411** |
| **Compound Annual Growth Rate** | | | | | | |
| **2025-34** | **0.33%** | **-1.02%** | **-0.12%** | **-0.46%** | **-6.56%** | **-0.22%** |

Table A.15 summarizes Wyoming state forecasted sales growth by customer class. Decrease in Wyoming retail sales are driven by expectations for the industrial and commercial classes.

**Table A.15 – Forecasted Retail Sales Growth in Wyoming, post-DSM**

| Wyoming Retail Sales – Megawatt-hours (MWh) | | | | | | |
|---|---|---|---|---|---|---|
| **Year** | Residential | Commercial | Industrial | Irrigation | Lighting | **Total** |
| **2025** | 1,055,290 | 1,395,430 | 6,353,361 | 30,568 | 11,755 | **8,846,405** |
| **2026** | 1,052,223 | 1,389,024 | 6,304,181 | 30,541 | 11,476 | **8,787,446** |
| **2027** | 1,047,511 | 1,372,121 | 6,294,536 | 30,400 | 11,062 | **8,755,629** |
| **2028** | 1,044,242 | 1,354,072 | 6,271,558 | 30,247 | 10,509 | **8,710,629** |
| **2029** | 1,031,575 | 1,327,283 | 6,257,618 | 30,059 | 9,714 | **8,656,249** |
| **2030** | 1,021,079 | 1,307,918 | 6,231,727 | 29,913 | 8,810 | **8,599,448** |
| **2031** | 1,011,399 | 1,293,146 | 6,227,447 | 29,865 | 7,856 | **8,569,713** |
| **2032** | 1,003,195 | 1,274,396 | 6,197,819 | 29,728 | 6,984 | **8,512,122** |
| **2033** | 988,757 | 1,248,112 | 6,167,046 | 29,553 | 6,213 | **8,439,681** |
| **2034** | 978,125 | 1,227,302 | 6,123,365 | 29,412 | 5,644 | **8,363,848** |
| **Compound Annual Growth Rate** | | | | | | |
| **2025-34** | **-0.84%** | **-1.42%** | **-0.41%** | **-0.43%** | **-7.83%** | **-0.62%** |

## Alternative Load Forecast Scenarios

The purpose of providing alternative load forecast cases is to determine the resource type and timing impacts resulting from a change in the economy or system peaks as a result of varying temperatures and economic conditions.

### High and Low Private Generation Scenarios

As noted above, DNV's Distributed Generation Forecast Behind-the-Meter Resource Assessment included results for three private generation scenarios, which includes the base, high, and low adoption projections. The high and low private generation load forecast scenarios rely on the high and low private generation adoption scenarios produced by DNV. Please refer to Appendix L – Distributed Generation Study for additional information regarding the methodology and assumptions used in the study.

### Optimistic and Pessimistic Scenarios

The May 2024 forecast is the baseline scenario. For the high and low load growth scenarios, optimistic and pessimistic economic driver assumptions from S&P Global Market Intelligence were applied to the economic drivers in PacifiCorp's load forecasting models. These growth assumptions were extended for the entire forecast horizon. Further, the high and low load growth scenarios also incorporate the standard error bands for the energy and the peak forecast to determine a 95% prediction interval around the base IRP forecast. The high scenario incorporates PacifiCorp's low private generation forecast, while the low scenario incorporates the high private generation forecast. Lastly, the high scenario incorporates high climate change temperatures, which are based on RCP 8.5 and the low scenario incorporate low climate change temperatures, which are based on RCP 4.5 (see Table A.5).

The 95% prediction interval is calculated at the system level and then allocated to each state and class based on their contribution to the variability of the system level forecast. The standard error bands for the jurisdictional peak forecasts were calculated in a similar manner. The final high load growth scenario includes the optimistic economic forecast and low private generation forecast plus the monthly energy adder and the monthly peak forecast with the peak adder. The final low load growth scenario includes the pessimistic economic forecast and high private generation forecast minus the monthly energy adder and monthly peak forecast minus the peak adder.

### 1-in-20 Year Scenario

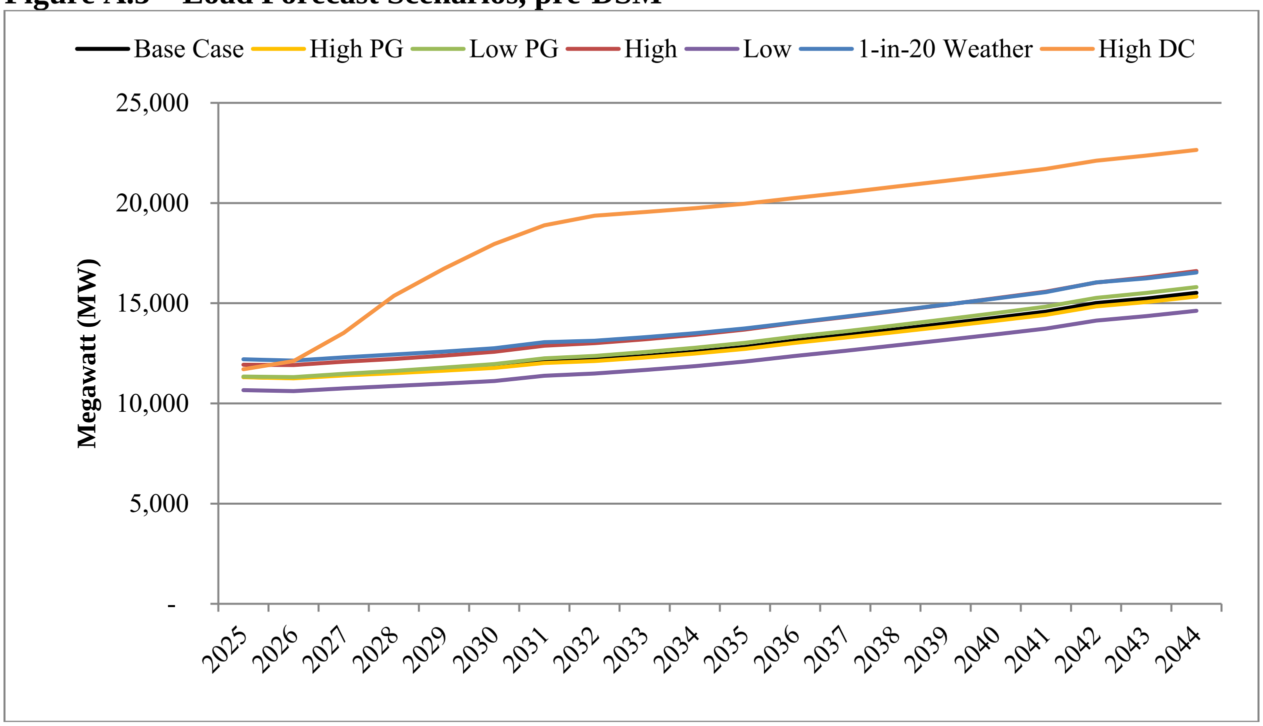
For the 1-in-20 year (5 percent probability) extreme weather scenario, PacifiCorp used 1-in-20 year peak weather for summer (July) months for each state. The 1-in-20 year peak weather is defined as the year for which the peak has the chance of occurring once in 20 years.

### High Data Center Scenario

The 2025 IRP incorporates a high data center scenario given that center load potential is emerging as a key driver to incremental resource and transmission needs across the industry. The high data center scenario accounts for all active data center requests from prospective data center customers assuming the demand materializes as requested by the customer.

Figure A.5 show the comparison of the above scenarios relative to the Base Case scenario.

**Figure A.5 – Load Forecast Scenarios, pre-DSM**



# APPENDIX B - REGULATORY COMPLIANCE

## Introduction

This appendix describes how PacifiCorp's 2025 Integrated Resource Plan (IRP) complies with (1) the various state commission IRP standards and guidelines, (2) specific analytical requirements stemming from acknowledgment orders for the company's 2023 Integrated Resource Plan, and other ongoing IRP acknowledgement order requirements as applicable, and (3) state commission IRP requirements stemming from other regulatory proceedings.

Included in this appendix are the following tables:

- Table B.1 - Provides an overview and comparison of the rules in each state for which an IRP submission is required.[1] The table is divided into topical subsections as follows:
  - (a) Source
  - (b) Filing Requirements
  - (c) Frequency
  - (d) Commission Response
  - (e) Process
  - (f) Focus
  - (g) Elements
- Table B.2 - Provides a description of how PacifiCorp addressed the 2023 IRP acknowledgement order requirements and other commission directives.[2]
- Table B.3 - Provides an explanation of how this plan addresses each of the items contained in the Oregon IRP guidelines.
- Table B.4 - Provides an explanation of how this plan addresses each of the items contained in the Public Service Commission of Utah IRP Standard and Guidelines issued in June 1992.
- Table B.5 - Provides an explanation of how this plan addresses each of the items contained in the Washington Utilities and Transportation Commission IRP rules issued in RCW 19.280.030 and WAC 480-100-620 through WAC 480-100-630 issued in December 2020.
- Table B.6 - Provides an explanation of how this plan addresses each of the items contained in the Wyoming Public Service Commission IRP guidelines updated in March 2016.

## General Compliance

PacifiCorp prepares the IRP on a biennial basis and files the IRP with state commissions. The preparation of the IRP is done in an open public process with consultation from all interested parties, including commissioners and commission staff, customers, and other stakeholders. This open process

[1] California Public Utilities Code Section 454.5 allows utility with less than 500,000 customers in the state to request an exemption from filing an IRP. However, PacifiCorp files its IRP and IRP supplements with the California Public Utilities Commission to address the company plan for compliance with the California RPS requirements.
[2] "Other commission directives" includes orders relevant to previous IRPs that contain ongoing requirements.

provides parties with a substantial opportunity to contribute information and ideas in the planning process and serves to inform all parties on the planning issues and approach. The public input process for this IRP is described in Chapter 2 (Introduction), as well as Appendix C (Public Input).

The IRP provides a framework and plan for future actions to ensure PacifiCorp continues to provide reliable and least-cost electric service to its customers. The IRP evaluates, over a twenty-year planning period, the future load of PacifiCorp customers and the resources required to meet this load.

To fill any gap between changes in loads and existing resources, while taking into consideration potential early retirement of existing coal units as an alternative to investments that achieve compliance with environmental regulations, the IRP evaluates a broad range of available resource options, as required by state commission rules. These resource options include supply-side, demand-side, and transmission alternatives. The evaluation of the alternatives in the IRP, as detailed in Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection Results) meets this requirement and includes the impact to system costs, system operations, supply and transmission reliability, and the impacts of various risks, uncertainties and externality costs that could occur.

To perform the analysis and evaluation, PacifiCorp employs a suite of models that simulate the complex operation of the PacifiCorp system and its integration within the Western interconnection. The models allow for a rigorous testing of a broad range of commercially feasible resource alternatives available to PacifiCorp on a consistent and comparable basis. The analytical process, including the risk and uncertainty analysis, fully complies with IRP standards and guidelines, and is described in detail in Chapter 8.

The IRP analysis is designed to define a resource plan that is least-cost, after consideration of risks and uncertainties. To evaluate resource alternatives and identify a least-cost, risk adjusted plan, portfolio resource options were developed and tested against each other. This testing included examination of various tradeoffs among the portfolios, such as average cost versus risk, reliability, customer rate impacts, and average annual carbon dioxide ($CO_2$) emissions. This portfolio analysis and the results and conclusions drawn from the analysis are described in Chapter 9.

Consistent with the IRP standards and guidelines of Oregon, Utah, and Washington, this includes an Action Plan in Chapter 10. The Action Plan details near-term actions that are necessary to ensure PacifiCorp continues to provide reliable and least-cost electric service after considering risk and uncertainty. The Action Plan also provides a progress report on action items contained in the 2023 IRP.

The 2025 IRP and related Action Plan are filed with each commission with a request for acknowledgment or acceptance, as applicable. Acknowledgment or acceptance means that a commission recognizes the IRP as meeting all regulatory requirements at the time of acknowledgment. In a case where a commission acknowledges the IRP in part or not at all, PacifiCorp may modify and seek to re-file an IRP that meets their acknowledgment standards or address any deficiencies in the next plan.

State commission acknowledgment orders or letters typically stress that an acknowledgment does not indicate approval or endorsement of IRP conclusions or analysis results. Similarly, an acknowledgment does not imply that favorable ratemaking treatment for resources proposed in the IRP will be given.

## California

Public Utilities Code Section 454.52, mandates that the California Public Utilities Commission (CPUC) adopt a process for load serving entities to file an IRP beginning in 2017. In February 2016, the CPUC opened a rulemaking to adopt an IRP process and address the scope of the IRP to be filed with the CPUC (Docket R.16-02-007).

Decision (D.) 18-02-018 directed PacifiCorp to file an alternative IRP consisting of any IRP submitted to another public regulatory entity within the previous calendar year (Alternative Type 2 Load Serving Entity Plan) along with an adequate description of treatment of disadvantaged communities, as well as a description of how planned future procurement is consistent with the 2030 Greenhouse Gas Benchmark.

PacifiCorp also provides its IRP and an IRP Supplement in lieu of providing a Renewables Portfolio Standard Procurement Plan, as authorized by Public Utilities Code Section 399.17(d). Requirements for PacifiCorp's IRP Supplement are outlined in an annual Assigned Commissioner's Ruling from the CPUC[3] and D.23-12-008. On March 7, 2024, PacifiCorp filed its 2023 IRP Supplement (2023 On-Year Supplement to its 2021 IRP) in Docket R.18-07-003. The Plan was approved in Decision 24-12-035, adopted December 19, 2024.

On October 18, 2019, PacifiCorp submitted its 2019 IRP in compliance with D.18-02-018.

On April 6, 2020, the CPUC issued D.20-03-028, which reiterated PacifiCorp's ability to file an alternative IRP.

On September 1, 2021, PacifiCorp filed its 2021 IRP in Docket R.18-07-003 in compliance with D.08-05-029.

On November 1, 2022, PacifiCorp filed its 2021 IRP in Docket R.20-05-003 in compliance with D.18-02-018, D.20-03-028, and D.22-02-004.

The California Public Utilities Commission is anticipated to issue IRP requirements in May 2025, with the Company's next Alternative IRP filing due November 2025.

California Public Utilities Code Section 454.5 allows utility with less than 500,000 customers in the state to request an exemption from filing an IRP. However, PacifiCorp files its IRP and IRP supplements with the California Public Utilities Commission to address the company plan for compliance with the California RPS requirements.

[3] The most recent Assigned Commissioner's Ruling is the *Assigned Commissioner and Assigned Administrative Law Judge's Ruling Identifying issues and Schedules of Review for 2022 Renewables Portfolio Standard Procurement Plans and Denying Joint IOU's Motion to File Advice Letters for Market Offer Process, Rulemaking 18-07-003 (April 11, 2022).*

## Idaho

The Idaho Public Utilities Commission's (Idaho PUC) Order No. 22299, issued in January 1989, specifies integrated resource planning requirements. This order mandates that PacifiCorp submit a Resource Management Report (RMR) on a biennial basis. The intent of the RMR is to describe the status of IRP efforts in a concise format, and cover the following areas:

> *Each utility's RMR should discuss any flexibilities and analyses considered during comprehensive resource planning, such as: (1) examination of load forecast uncertainties; (2) effects of known or potential changes to existing resources; (3) consideration of demand and supply side resource options; and (4) contingencies for upgrading, optioning and acquiring resources at optimum times (considering cost, availability, lead time, reliability, risk, etc.) as future events unfold.*

This IRP is submitted to the Idaho PUC as the Resource Management Report for 2025 and fully addresses the above report components.

## Oregon

This IRP is submitted to the Oregon Public Utility Commission (OPUC) in compliance with its planning guidelines issued in January 2007 (Order No. 07-002 as amended by Order No. 07-047). The Oregon PUC's IRP guidelines consist of substantive requirements (Guideline 1), procedural requirements (Guideline 2), plan filing, review, and updates (Guideline 3), plan components (Guideline 4), transmission (Guideline 5), conservation (Guideline 6), demand response (Guideline 7), environmental costs (Guideline 8, Order No. 08-339), direct access loads (Guideline 9), multi-state utilities (Guideline 10), reliability (Guideline 11), distributed generation (Guideline 12), resource acquisition (Guideline 13), flexible resource capacity (Order No. 12-013 ), and renewable portfolio standard planning (HB 3161 ORS 469A.075). Consistent with the earlier guidelines (Order 89-507[4]), the Oregon PUC notes that acknowledgment does not guarantee favorable ratemaking treatment, only that the plan seems reasonable at the time acknowledgment is given. Table B.3 provides detail on how this plan addresses each of the requirements.[5]

## Utah

This IRP is submitted to the Public Service Commission of Utah in compliance with its 1992 Order on Standards and Guidelines for Integrated Resource Planning (Docket No. 90-2035-01, "Report and Order on Standards and Guidelines"). Table B.4 documents how PacifiCorp complies with each of these standards.

## Washington

This IRP is submitted to the Washington Utilities and Transportation Commission (WUTC) in compliance with its required four-year filing cadence. In its report, the rule requires PacifiCorp to

[4] Public Utility Commission of Oregon, Order No. 12-013, Docket No. 1461, January 19, 2012.

[5] During the 2025 IRP public input meeting series, an inquiry was made regarding the requirement to provide an IRP Update in between major IRP filings. See Appendix M, stakeholder feedback form #8 (Western Resource Advocates) for discussion of this requirement.

include: a range of load forecasts; assessments of distributed and supply-side resources, renewable resource integration, regional generation and transmission, resource adequacy, and comparative resource evaluation; evaluation of economic, health, and environmental burdens and benefits; scenarios and sensitivities; and portfolio analysis including the development of a preferred portfolio. In addition, Washington requires the inclusion of a Clean Energy Action Plan per Washington RCW 19.280.030 and WAC 480-100-620, which is provided as Appendix O (Clean Energy Action Plan). Table B.5 documents how PacifiCorp complies with each of these standards.

## Wyoming

Currently Chapter 3, Section 33 of the Wyoming Public Service Commission rules outlines the requirements on filing IRPs for any utility serving Wyoming customers. The rule, shown below, went into effect in March 2016.

> ***Section 33. Integrated Resource Plan (IRP).*** *Each utility serving in Wyoming that files an IRP in another jurisdiction shall file that IRP with the Commission. The Commission may require any utility to file an IRP.*

In August 2024, the Wyoming Public Service Commission issued a Notice of Technical Conference and Call for Comments to consider engaging in a rulemaking to determine if additional rule requirements are necessary to comply with newly enacted Wyoming Statute § 37-2-135 that went into effect on July 1, 2024, which requires the Commission to review IRP action plans. PacifiCorp is participating in the public rulemaking process.

Table B.6 documents how PacifiCorp complies with Wyoming guidelines.

**Table B.1 – Integrated Resource Planning Standards and Guidelines Summary by State**

| B.1(a) IRP Guidelines - Source | | | | |
|---|---|---|---|---|
| **Oregon** | **Utah** | **Washington** | **Idaho** | **Wyoming** |
| Order No. 07-002, *Investigation into Integrated Resource Planning*, January 8, 2007, as amended by Order No. 07-047.<br><br>Order No. 08-339, *Investigation into the Treatment of CO2 Risk in the Integrated Resource Planning Process*, June 30, 2008.<br><br>Order No. 09-041, New Rule OAR 860-027-0400, implementing Guideline 3, "Plan Filing, Review, and Updates".<br><br>Order No. 12-013, "Investigation of Matters related to Electric Vehicle Charging", January 19, 2012<br><br>Order No. 23-061, "Reconsideration of Order No. 22-390 Granted in Part; Reconsideration of Order Nos. 22-446 and 22-477 Denied, February 24, 2023. | Docket 90-2035-01 *Standards and Guidelines for Integrated Resource Planning* June 18, 1992. | WAC 480-100-620 *Content of an integrated resource plan. Filed 12/28/20, effective 12/31/20.*<br><br>WAC 480-100-625 *Integrated resource plan development and timing. Filed 12/28/20, effective 12/31/20.*<br><br>WAC 480-100-630 *Integrated resource planning advisory groups. Filed 12/28/20, effective 12/31/20.* | Order 22299 *Electric Utility Conservation Standards and Practices* January 1989. | Wyoming Electric, Gas and Water Utilities, Chapter 3, Section 33, March 21, 2016. |

| B.1(b) IRP Guidelines - Filing Requirements | | | | |
|---|---|---|---|---|
| **Oregon** | **Utah** | **Washington** | **Idaho** | **Wyoming** |
| Least-cost plans must be filed with the Oregon PUC, including a Clean Energy Plan. | An IRP is to be submitted to commission. | Submit a least-cost plan to the WUTC every four years, including a Clean Energy Action Plan. Plan to be developed with consultation of WUTC staff, and with public involvement. | Submit Resource Management Report on planning status. Also, file progress reports on conservation, low-income programs, lost opportunities and capability building. | Each utility serving in Wyoming that files and IRP in another jurisdiction, shall file the IRP with the commission. |

| B.1(c) IRP Guidelines - Frequency | | | | |
|---|---|---|---|---|
| **Oregon** | **Utah** | **Washington** | **Idaho** | **Wyoming** |
| Plans filed biennially, within two years of its previous IRP acknowledgment order. An annual update to the most recently acknowledged IRP is required to be filed on or before the one-year anniversary of the acknowledgment order date. While informational only, utilities may request acknowledgment of proposed changes to the action plan. | File biennially. | Unless otherwise ordered by the commission, each electric utility must file an integrated resource plan (IRP) with the commission by January 1, 2021, and every four years thereafter.<br><br>At least every two years after the utility files its IRP, beginning January 1, 2023, the utility must file a two-year progress report. | RMR to be filed at least biennially. Conservation reports to be filed annually. Low income reports to be filed at least annually. Lost Opportunities reports to be filed at least annually. Capability building reports to be filed at least annually. | The commission may require any utility to file an IRP. |

| B.1(d) IRP Guidelines - Commission Response | | | | |
|---|---|---|---|---|
| **Oregon** | **Utah** | **Washington** | **Idaho** | **Wyoming** |
| Least-cost plan (LCP) *acknowledged* if found to comply with standards and guidelines. A decision made in the LCP process does not guarantee favorable rate-making treatment. The OPUC may direct the utility to revise the IRP or conduct additional analysis before an acknowledgment order is issued. | IRP acknowledged if found to comply with standards and guidelines. Prudence reviews of new resource acquisitions will occur during rate making proceedings.<br><br>Note, however, that Rate Plan legislation allows pre-approval of near-term resource investments. | The plan will be considered, with other available information, when evaluating the performance of the utility in rate proceedings.<br><br>WUTC no longer acknowledges IRPs. | Report does not constitute pre-approval of proposed resource acquisitions.<br><br>Idaho sends a short letter stating that they accept the filing and acknowledge the report as satisfying commission requirements. | Commission advisory staff reviews the IRP as directed by the Commission and drafts a memo to report its findings to the commission in an open meeting or technical conference. |

| B.1(e) IRP Guidelines - Process | | | | |
|---|---|---|---|---|
| **Oregon** | **Utah** | **Washington** | **Idaho** | **Wyoming** |
| The public and other utilities are allowed significant involvement in the preparation of the plan, with opportunities to contribute and receive information. Order 07- 002 requires that the utility present IRP results to the Oregon PUC at a public meeting prior to the deadline for written public comments.<br>Commission staff and parties should complete their comments and recommendations within six months after IRP filing. Competitive secrets must be protected. | Planning process open to the public at all stages. IRP developed in consultation with the commission, its staff, with ample opportunity for public input. | In consultation with WUTC staff, develop and implement a public involvement plan.<br><br>PacifiCorp is required to submit a work plan for informal commission review not later than 15 months prior to the due date of the plan.<br><br>The utility must file its draft IRP with the commission four months prior to the filing of an IRP. (a) The commission will hear public comment on the draft IRP at an open meeting once filed. (b) The utility must file draft IRP presentation materials at least five business days prior to the open meeting. | Utilities to work with commission staff when reviewing and updating RMRs. Regular public workshops should be part of process. | The review may be conducted in accordance with guidelines set from time to time as conditions warrant.<br><br>The Public Service Commission of Wyoming, in its Letter Order on PacifiCorp's 2008 IRP (Docket No. 20000-346- EA-09) adopted commission Staff's recommendation to expand the review process to include a technical conference, an expanded public comment period, and filing of reply comments. |

| B.1(f) IRP Guidelines - Focus | | | | |
|---|---|---|---|---|
| **Oregon** | **Utah** | **Washington** | **Idaho** | **Wyoming** |
| 20-year plan, with end-effects, and a short-term (two-year) action plan. The IRP process should result in the selection of that mix of options which yields, for society over the long run, the best combination of expected costs and variance of costs. | 20-year plan, with short- term (four-year) action plan. Specific actions for the first two years and anticipated actions in the second two years to be detailed. The IRP process should result in the selection of the optimal set of resources given the expected combination of costs, risk and uncertainty. | 20-year plan, which describes mix of resources sufficient to meet current and future loads and CETA standards at "lowest reasonable" cost. Resource cost, market volatility risks, demand-side resource uncertainty, resource dispatchability, ratepayer risks, policy impacts, environmental risks, and equitable distribution of benefits must be considered. Utilities must develop a ten-year clean energy action plan for implementing RCW 19.405.030 through 19.405.050. | 20-year plan to meet load obligations at least-cost, with equal consideration to demand side resources. Plan to address risks and uncertainties. Emphasis on clarity, understandability, resource capabilities and planning flexibility. | Identification of least-cost/least-risk resources and discussion of deviations from least-cost resources or resource combinations. |

| B.1(g) IRP Guidelines - Elements | | | | |
|---|---|---|---|---|
| **Oregon** | **Utah** | **Washington** | **Idaho** | **Wyoming** |
| Basic elements include:<br>• Consistent and comparable resource evaluation.<br>• Risk and uncertainty must be considered.<br>• Least cost planning, consistent with the long-run public interest.<br>• Consistent with Oregon and federal energy policy.<br>• External costs must be considered, and quantified where possible. OPUC specifies environmental adders (Order No. 93-695, Docket UM 424).<br>• Multi-state utilities should plan their generation and transmission systems on an | IRP will include:<br>• Range of forecasts of future load growth<br>• Evaluation of all present and future resources, including demand side, supply side and market, on a consistent and comparable basis.<br>• Analysis of the role of competitive bidding<br>• A plan for adapting to different paths as the future unfolds.<br>• A cost effectiveness methodology.<br>• An evaluation of the financial, competitive, | Basic elements:<br>• A range of forecasts that examine the effect of economic forces on the consumption of electricity.<br>• An assessment of conservation and load management, and policies and programs to achieve conservation.<br>• Assessment of a wide range of generating technologies.<br>• Assessment of transmission system capability and reliability.<br>• Evaluation of energy supply resources (including transmission and distribution) using "lowest reasonable cost" criteria. | Discuss analyses considered including:<br>• Load forecast uncertainties.<br>• Changes to existing resources.<br>• Equal consideration of demand and supply side resources.<br>• Contingencies for upgrading, optioning and acquiring resources at optimum times.<br>• Report on existing resource stack, load forecast and additional resource menu. | Commission IRP guidelines cover:<br>• Sufficiency of the public comment process.<br>• Utility strategic goals, resource planning goals and preferred resource portfolio.<br>• Resource need over the near-term and long- term planning horizons.<br>• Types of resources considered.<br>• Changes in expected resource acquisitions and load growth from the previous IRP.<br>• Environmental impacts considered.<br>• Market purchase |

| B.1(g) IRP Guidelines - Elements | | | | |
|---|---|---|---|---|
| **Oregon** | **Utah** | **Washington** | **Idaho** | **Wyoming** |
| integrated-system basis.<br>• Construction of resource portfolios over the range of identified risks and uncertainties.<br>• Portfolio analysis shall include fuel transportation and transmission requirements.<br>• Plan includes conservation potential study, demand response resources, environmental costs, and distributed generation technologies.<br>• Avoided cost filing required within 30 days of acknowledgment.<br>• IRP includes a description of the electric company's plan for meeting the requirements of the renewable portfolio standard. | reliability and operational risks associated with resource options, and how the action plan addresses these risks.<br>• Definition of how risks are allocated between ratepayers and shareholders | • Resource adequacy metrics.<br>• Energy and nonenergy benefits and reductions of burdens to vulnerable populations and highly impacted communities; health and environmental benefits, costs, and risks.<br>• Long-range plan (10+ years).<br>• Progress report compared to the previously filed plan.<br>• Clean energy action plan for implementing RCW 19.405.030 through 19.405.050.<br>• Summary of changes to modeling methodologies or inputs compared to the utility's previous IRP.<br>• Analysis and summary of avoided costs; list of nonenergy costs and benefits and how they accrue.<br>• Summary of public comments and utility responses. | | evaluation.<br>• Reserve margin analysis.<br>• Demand-side management and conservation options. |

**Table B.2 – Handling of Previous IRP Acknowledgments and Other IRP Requirements**

| B.2(a) - Idaho | | |
|---|---|---|
| **Reference** | **Requirement or Recommendation** | **2025 IRP Approach** |
| Order No. 35514 p. 17 | …we encourage the Company to continue exploring an approach in its IRP process that allows for a reasonable and accurate selection of cost-effective natural gas resources in a portfolio. | As a consequence of changing exogenous risks, new natural gas resources are included for selection in the 2025 IRP. |
| Order No. 35514 p. 17 | Finally, we acknowledge the inherent complexities with the Natrium project and direct the Company to continue to assess the risks of technology viability and potential delays with Natrium and plan accordingly. | In this cycle, Natrium is anticipated to come online in the fall of 2031 (modeled as 1/1/2032). Consistent with the 2023 IRP, the 2025 IRP includes variant analysis with no Natrum project as described in Chapters 8 and 9, designed to inform alternative path analysis and potential costs and benefits. PacifiCorp continues to evaluate nuclear resources within the context of an evolving planning environment. |
| Order 35977 p. 3 | …the Company explained that it expects that its 2025 IRP will include discussion of the impacts of WRAP compliance and will include appropriate modeling of planning reserve margin and resource requirements. | For the 2025 IRP, PacifiCorp meets these expectations with the inclusion of WRAP compliance, planning reserve margin and resource requirements as described in Chapters 6, 7 and 8. |

| B.2(b) - Oregon | | |
|---|---|---|
| **Reference** | **Requirement or Recommendation** | **2025 IRP Approach** |
| Order No. 22-178, p. 13 | In order to connect new resources to the grid, it is critical not only that transmission be built, but that the right transmission be built; the Commission and stakeholders need to have sufficient information to verify that ratepayers are getting the benefits they are paying for at each stage of development. Going forward, we expect PacifiCorp to provide information that allows that assessment at the outset. We also expect the company to actively encourage key stakeholders like Commission Staff and consumer advocates to participate and provide | IRP modeling accounts for cost, location, total transfer capability and resource enabled by transmission options. Options are modeled endogenously, and selections are driven primarily by the need to increase interconnection to allow efficient system transfer and to serve load. In the 2025 IRP, costs, descriptions, and transfer capabilities are defined, and in addition near-term transfer options are rooted in cluster study and queue analysis and informed by surplus resource options which allow for transmission costs to be avoided where appropriate. The transmission option modeling strategy was discussed at three public input meetings spanning May 2, 2024 through August 15, 2024 with opportunities for feedback and recommendations. PacifiCorp also responded to stakeholder comments in stakeholder feedback forms during the public input process.[6] Also, modeling of small scale renewable resources for both the IRP and CEP assumes there are no accompanying transmission requirements, providing an additional |

[6] See Appendix M, stakeholder feedback form #17 (OPUC), stakeholder feedback form #17 (OPUC), stakeholder feedback form #40 (RNW).

| B.2(b) - Oregon | | |
|---|---|---|
| **Reference** | **Requirement or Recommendation** | **2025 IRP Approach** |
| | a larger window into its own transmission planning processes. | opportunity to evaluate transmission avoidance beyond the native core functionality of the PLEXOS model. See Chapter 4 (Transmission), and Chapter 8 (Modeling and Portfolio Evaluation). |
| Order No. 22-178, p. 15; Appx B p. 1 | We expect PacifiCorp to engage in the company's local transmission planning process as appropriate and to request that sufficient information to inform consideration of offshore wind in future IRPs is made available in this local transmission study cycle. | PacifiCorp, in April 2023, completed an Economic Study Request ("ESR"), submitted by the Oregon Public Utility Commission ("OPUC") Staff to have PacifiCorp evaluate the effects of 1.0 GW of Offshore Wind (OSW) generation in southern Oregon, assumed to be interconnected to PacifiCorp's Del Norte substation located in Del Norte, California. PacifiCorp participated in the Technical Focus Group for the October 2023 Northern California and Southern Oregon Offshore Wind Transmission Study led by Schatz Energy Research Center and is Contributor in the U.S. Department of Energy led West Coast Offshore Wind Transmission Study, currently underway as of 2025. These efforts inform both the local transmission plan and transmission modeling options available to the IRP model. |
| Order No. 22-178, p. 18; Appx B p. 1 | PacifiCorp to provide a map of resources in the IRP Executive Summary, which PacifiCorp agrees to do. | This requirement is met by the preferred portfolio map provided in Appendix I (Capacity Expansion Results). |
| Order No. 22-178, Appx B p. 2 | In future IRPs or during future RFP processes, potential RFP bidders should be given access to a 12x24 Loss of Load Probability matrix for one out of every five years in the IRP planning timeframe. | Following the completion of the 2021 IRP and in advance of bid submissions in the 2022 All-Source RFP, PacifiCorp prepared the requested information and provided it to stakeholders in its January 25, 2022, filing in docket UM 2011. Following the completion of the 2025 IRP, PacifiCorp will develop comparable information for use in future RFP processes. |
| Order No. 24-073 | Direct PacifiCorp to provide specific baseline metrics in the 2025 IRP/CEP to allow for measured progress towards CBI goals. | PacifiCorp anticipates including any available and applicable baseline metrics for its community benefit indicators (CBIs) goals in its forthcoming 2025 Clean Energy Plan. |
| Order No. 24-073 | In the 2025 IRP/CEP, direct PacifiCorp to update Natrium assumptions to reflect actual events. | For the 2025 IRP, Natrium assumptions have been updated to the extent possible as described in Chapter 7 (Resource Options). |

| B.2(b) - Oregon | | |
|---|---|---|
| **Reference** | **Requirement or Recommendation** | **2025 IRP Approach** |
| Order No. 24-073 | In the 2025 IRP/CEP model, PacifiCorp must: (1) demonstrate that simultaneous compliance with all state-level policies is feasible with the least-cost, least-risk Preferred Portfolio and with the Preferred Portfolio variants tested in the IRP under multiple allocations. | In the 2025 IRP, each jurisdiction's resources are optimally selected in compliance with its unique requirements and then integrated into the preferred portfolio. Existing resources are assumed to be allocated consistent with what is currently approved in each states' rates for cost-allocations. Proxy resource selections, as they are driven by a jurisdictions' specific need and obligations, are generally assumed to be situs cost allocated. Allocation strategies were not used to demonstrate compliance with HB 2021 in the creation of the preferred portfolio. Additional cost-allocation strategies or variants will be tested in the 2025 CEP. |
| Order No. 24-073 | In the 2025 IRP/CEP, PacifiCorp shall include an analysis of forecasted costs and annual emissions of the Preferred Portfolio using only actual carbon prices in effect in 2025 through the 20-year planning horizon. | In the 2025 IRP, this requirement is met through the base assumptions of the medium gas price / no carbon price (MN) scenario. PacifiCorp also models other price-policy scenarios considering alternative carbon price futures. |
| Order No. 24-073 | In the 2025 IRP/CEP, PacifiCorp shall calculate and report the costs and GHG emissions associated with each portfolio assuming that GHG prices are not reflected in dispatch decisions but still included in investment and retirement decisions. | The base or 'expected' case assumption in the 2025 IRP for the preferred portfolio and all variants has no GHG cost adder for Oregon (and system) resource selections or dispatch. Other jurisdictions' modeling requirements include GHG emissions as a cost-adder for the selection of their resources. Other price policies (as indicated by their names) may have GHG emissions costs which impact dispatch, but these portfolios are for analytics and not selectable as the preferred portfolio. |
| Order No. 24-073 | In the 2025 IRP/CEP PacifiCorp shall provide an explanation of renewable cost assumptions and a comparison to recent pricing information from such organizations as National Renewable Energy Lab and Lazard. | The 2025 IRP provides an expanded explanation of resource cost determinations and data sourcing. See Chapter 7 (Resource Options). |
| Order No. 24-073 | In the 2025 IRP/CEP, PacifiCorp shall confirm that coal generator cost assumptions reasonably reflect the structure and terms of any associated fuel supply agreements or fuel supply plans. Categorize variable costs that affect dispatch as variable costs in the model with as much accuracy as reasonably possible. | PacifiCorp updated coal costs and assumptions in September 2024 leveraging the most current future cost and performance estimates available to the company. Any items which are based on generation (fuel, emissions, variable O&M etc.) have been confirmed with subject matter experts for accuracy. |

| B.2(b) - Oregon | | |
|---|---|---|
| **Reference** | **Requirement or Recommendation** | **2025 IRP Approach** |
| Order No. 24-073 | In the 2025 IRP/CEP PacifiCorp shall report on steps that the Company took to reduce the magnitude of reliability and granularity adjustments, how the Company engaged with stakeholders on adjustments, and describe the methodology and report the resulting reliability and granularity adjustments by resource. Include any supporting work papers demonstrating the granularity/reliability adjustments in the Data Disk. | As in the 2023 IRP and 2023 IRP Update, all workpapers for granularity/reliability adjustments are included in the 2025 IRP workpaper filing.[7] PacifiCorp engaged with stakeholders regarding granularity/reliability adjustments in five public input meetings spanning January 25, 2024 through September 25, 2024. PacifiCorp also provided additional detail in response to stakeholder feedback forms.[8]<br><br>The enhancements of the iterative approach to modeling have led to more efficient model outcomes. All resources included in jurisdictional portfolios were endogenously selected by the model, and the integrated portfolios only include resources selected in the best of the compliant jurisdictional portfolios. |
| Order No. 24-073 | In the 2025 IRP/CEP PacifiCorp shall provide an update on PacifiCorp's efforts to secure Energy Infrastructure Reinvestment (EIR) financing from the DOE Loan Program Office. Assume EIR financing through the DOE Loan Program Office in the Preferred Portfolio or include a variant portfolio that optimizes resource additions and retirements under the assumption of EIR financing. | PacifiCorp has been selected for a $3.52 billion conditional DOE federal loan through Project WIRE to support multiple transmission projects across four states, benefiting customers in California, Idaho, Oregon and Utah.[9]<br><br>The High IRA adoption sensitivity fulfills the study request in this order. |
| Order No. 24-073 | Acknowledge updated avoided costs from the 2023 IRP planning and direct PacifiCorp to work with Staff and Stakeholders to update avoided costs for use in UM 1893 considering HB 2021 constraints. | PacifiCorp's November 2024 energy efficiency avoided cost submittal in docket UM 1893 included incremental value associated with the need for clean energy resources for compliance with HB 2021. PacifiCorp's submittal in response to Staff's proposal for qualifying facility avoided costs in docket UM 2000 also includes incremental value related to HB 2021. PacifiCorp expects this concept to be further developed in its 2025 CEP, and to continue to evolve as it applied in specific programs and rates. |
| Order No. 24-297 | PacifiCorp's next Clean Energy Plan filing must contain an executable action plan. | The 2025 IRP, Appendix P includes a near-term action plan to work towards meeting Oregon states obligations and HB 2021 compliance. This near-term action plan will be executed upon and/or further refined in the 2025 CEP. |

[7] Note that 'data disk' is a carry-over from the days of providing physical media, and Pacific is transitioning to refer to public, confidential and highly confidential 'workpapers'.
[8] Refer to Appendix M, stakeholder feedback form #17 (OPUC) and stakeholder feedback form #36 (Sierra Club).
[9] PacifiCorp Lands $3.5B Federal Loan for Transmission Projects in Four States | Clearing Up | newsdata.com

| B.2(b) - Oregon | | |
|---|---|---|
| **Reference** | **Requirement or Recommendation** | **2025 IRP Approach** |
| HB 3162, ORS 469A.075 | IRP includes a description of the electric company's plan for meeting the requirements of the renewable portfolio standard | See Appendix R (Renewable Portfolio Implementation Plan). |

| B.2(c) - Utah | | |
|---|---|---|
| **Reference** | **Requirement or Recommendation** | **2025 IRP Approach** |
| Docket No. 90-2035-01 p. 33-37 | The forecasts will be made by jurisdiction and by general class and will differentiate energy and capacity requirements. The Company will include in its forecasts all on-system loads and those off-system loads which they have a contractual obligation to fulfill. Non-firm off-system sales are uncertain and should not be explicitly incorporated into the load forecast that the utility then plans to meet. However, the Plan must have some analysis of the off-system sales market to assess the impacts such markets will have on risks associated with different acquisition strategies. | PacifiCorp's load forecast is developed for each jurisdiction and by customer class. Further, this forecast includes off-system wholesale customers for which the Company has a contractual obligation to fulfill. To plan for non-firm off-system customer impacts returning to PacifiCorp's system, 1-year and 3-year option direct access customers in Oregon are incorporated into the forecast assuming they will return once their opt-out period expires. |
| Docket No. 90-2035-01 p. 33-39 | Analyses of how various economic and demographic factors, including the prices of electricity and alternative energy sources, will affect the consumption of electric energy services, and how changes in the number, type and efficiency of end-uses will affect future loads. | PacifiCorp has evaluated these market conditions to inform a least-cost, least-risk preferred portfolio outcome. Changes to consumer behavior are also outlined under the suite of existing demand-side management, energy efficiency and load forecast projections at the disposal of the Company. |
| Docket No. 90-2035-01 p. 33-39 | An evaluation of all present and future resources, including future market opportunities (both demand-side and supply-side), on a consistent and comparable basis. | PacifiCorp has included a wide range of potential resource options within its supply-side table and has included reasonable cost estimates for all resource types. Where costs and operating characteristics are similar, as with different lithium-ion chemistries, the IRP does not attempt to differentiate. Differences in performance are expected to be well within the normal range of offers from bidders. Even non-emitting peaking and nuclear resources are ultimately proxies for their particular combinations of costs, operating characteristics, and risks. Many types of risks are expected to evolve over the next few planning cycles including risks associated with these new technologies, and those associated with emitting technologies. |

| B.2(c) - Utah | | |
|---|---|---|
| **Reference** | **Requirement or Recommendation** | **2025 IRP Approach** |
| Docket No. 90-2035-01 p. 33-37 | An assessment of all technically feasible and cost-effective improvements in the efficient use of electricity, including load management and conservation. | PacifiCorp has evaluated all technically feasible and cost-effective energy efficiency, conservation, and load management through the Conservation Potential Assessment to compete with other resources in the IRP modeling. |
| Docket No. 90-2035-01 p. 33-39 | An assessment of all technically feasible generating technologies including: renewable resources, cogeneration, power purchases from other sources, and the construction of thermal resources. | PacifiCorp has evaluated all known technically feasible generating technologies including renewable resources, cogeneration, and the construction of thermal resources. The IRP does not represent ownership structures for proxy resources. Procurement for any resource could result in a Build Transfer Agreement (BTA), Power Purchase Agreement (PPA), self-build, or other contract structure. |
| Docket No. 90-2035-01 p. 33-39 | The resource assessments should include: life expectancy of the resources, the recognition of whether the resource is replacing/adding capacity or energy, dispatchability, lead-time requirements, flexibility, efficiency of the resource and opportunities for customer participation. | The resource assessments include life expectancy of the resources, the recognition of whether the resource is replacing/adding capacity or energy, dispatchability, lead-time requirements, flexibility, and efficiency of the resource and opportunities for customer participation. |
| Docket No. 90-2035-01 p. 33-39 | An analysis of the role of competitive bidding for demand-side and supply-side resource acquisitions. | Demand side resources are evaluated as part of the IRP modeling to evaluate overall competitiveness with other resources. |
| Docket No. 90-2035-01 p. 33-39 | A 20-year planning horizon. | The 2025 IRP covers a 21-year horizon from 2025 through 2045. This is an exception to the standard coverage requirement of 20 years and was extended in this cycle to meet a 2045 requirement pertaining to Washington Docket UE-210829, Order 06. |
| Docket No. 90-2035-01 p. 33-39 | A two-year action plan outlining the specific resource decisions intended to implement the integrated resource plan in a manner consistent with the Company's strategic business plan. | This requirement is met in Chapter 10 (Action Plan). |
| Docket No. 90-2035-01 p. 33-39 | An action plan outlining the specific resource decisions intended to implement the integrated resource plan in a manner consistent with the Company's strategic business plan. The action plan will span a four-year horizon and will describe specific actions to be taken in the first two years and outline actions anticipated in the last two years. The action plan will include a status report of the specific actions contained in the previous action plan. | This requirement is met in Chapter 10 (Action Plan). |

| B.2(c) - Utah | | |
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| **Reference** | **Requirement or Recommendation** | **2025 IRP Approach** |
| Docket No. 90-2035-01 p. 33-39 | Load forecasts integrated with resource options in a manner which rationalizes the choice of resources under a variety of economic circumstances. | Modeling for the 2025 IRP incorporates multiple load forecasts and price-policy scenarios under which resources compete on an optimized basis for the selection of resource options, retirements, unit conversions, transmission options, market purchases and sales, and other elements. See Chapters 7, 8 and 9. |
| Docket No. 90-2035-01 p. 33-39 | A plan of different resource acquisition paths for different economic circumstances with a decision mechanism to select among and modify these paths as the future unfolds. | PacifiCorp presents its alternative path analysis in Chapter 10 (Action Plan). |
| Docket No. 90-2035-01 p. 33-39 | An evaluation of the cost-effectiveness of the resource options from a variety of perspectives and society as a whole. | PacifiCorp's 2025 IRP evaluates risk via a risk-adjustment metric based on stochastic modeling results, provides a set of competitive variant portfolios, and includes studies assuming a social cost of greenhouse gas cost-adder as a price-policy scenario. |
| Docket No. 90-2035-01 p. 33-39 | An evaluation of the risks associated with various resource options and how the action plan addresses these risks in the context of both the Business Plan and the 20-year Integrated Resource Plan. | PacifiCorp's 2025 IRP evaluates risk via a risk-adjustment metric based on stochastic modeling results and includes a Business Plan sensitivity. The 2025 IRP will be used to inform the Business Plan. |
| Docket No. 90-2035-01 p. 33-39 | An evaluation of the financial, competitive, reliability, and operational risks associated with various resource options and how the action plan addresses these risks in the context of both the Business Plan and the 20-year Integrated Resource Plan. The Company will identify who should bear such risk, the ratepayer or the stockholder. | The 2025 IRP endogenously evaluates the attributes of competing resource options through its input data, which is reflective of the costs, operational characteristics, technology type, location, interconnection availability and other factors. In addition, the RFP non-price scoring process evaluates, in coordination with several independent evaluators representing three states, the project and reliability risks and scores these results accordingly. The assumptions in the Business Plan and 20-year Integrated Resource Plan are ultimately modified and realized through actual generating projects that are either owned or under contract and represent ratepayer risk, not shareholder risk, except to the extent that the commitments or actions of the Company are deemed imprudent in a future ratemaking proceeding. During RFP procurements, the terms of contracts are also reviewed by independent evaluators and are available and submitted to regulatory staff upon request or by order or statute. These contracts include performance guarantees to balance the risk between the project owner and the Company on behalf of ratepayers. |

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| **Reference** | **Requirement or Recommendation** | **2025 IRP Approach** |
| Docket No. 90-2035-01 p. 33-39 | Considerations permitting flexibility in the planning process so that the Company can take advantage of opportunities and can prevent the premature foreclosure of options. | PacifiCorp assesses the potential value of resources against risk and the expense of time and resources in the development of its supply side resources. The 2025 IRP public input process included materials and discussion of supply side resources in six meetings spanning January 2024 through September 2024. Resources were a topic of interest in numerous stakeholder feedback forms submitted during the 2025 IRP development process. Refer to Appendix M for a full list of publicly available feedback and responses. |
| Docket No. 90-2035-01 p. 33-39 | An analysis of tradeoffs; for example, between such conditions of service as reliability and the acquisition of lowest cost resources. | The 2025 IRP inherently evaluates trade-offs between reliability and resource cost, as well as operational costs incurred during dispatch as part of the core functionality of optimization modeling. Additional analysis is provided in narrative form where salient trade-offs are indicated in portfolio outcomes. See Chapter 9 (Modeling and Portfolio Selection Results). |
| Docket No. 90-2035-01 p. 33-39 | A range, rather than attempts at precise quantification, of estimated external costs which may be intangible, in order to show how explicit consideration of them might affect selection of resource options. The Company will attempt to quantify the magnitude of the externalities, for example, in terms of the amount of emissions released and dollar estimates of the costs of such externalities. | Future environmental and safety regulation has an almost unfathomable potential range of outcomes, many of which may be contradictory with other rules or policy goals, as in restrictions on non-emitting resources. What is certain, is that compliance may involve costs dramatically in excess of even the social cost of greenhouse gases price-policy scenario. As an example, coal ash handling and water treatment is only partly related to ongoing operations, but the costs could offset years of possible operational benefits depending on the circumstances. Environmental and safety regulation is not limited to fossil fuel resources, a few very basic examples include:<br><br>Very few battery chemistries have significant history in utility-scale operations, and some examples of fire hazards have been identified.<br><br>Wind turbines present risks related to birds and bats.<br>Cadmium telluride solar panels include two toxic chemicals, which while significantly less harmful in compound form, do not have well documented long-term effects.<br><br>The above is not intended to be comprehensive - all technologies have trade-offs and risks though some technologies have more unknown unknowns than others. The largest externality of which the Company is currently aware is the impact of greenhouse gases on the climate. A |

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| **Reference** | **Requirement or Recommendation** | **2025 IRP Approach** |
| | | price-policy scenario with an estimate of the social cost of greenhouse gases is used to quantify that particular externality, and analysis including those costs is presented for the preferred portfolio and selected variant portfolios. |
| Docket No. 90-2035-01 p. 33-39 | The public, state agencies and other interested parties will have the opportunity to make formal comment to the Commission on the adequacy of the Plan. The Commission will review the Plan for adherence to the principles stated herein and will judge the merit and applicability of the public comment. If the Plan needs further work the Commission will return it to the Company with comments and suggestions for change. This process should lead more quickly to the Commission's acknowledgement of an acceptable Integrated Resource Plan. The Company will give an oral presentation of its report to the Commission and all interested public parties. Formal hearings on the acknowledgement of the Integrated Resource Plan might be appropriate but are not required. 7. Acknowledgement of an acceptable Plan will not guarantee favorable ratemaking treatment of future resource acquisitions. | PacifiCorp will participate fully in the described process. |
| Docket No. 21-035-09, UPSC June 2, 2022 Order p. 5-8 | PacifiCorp must comply with Guidelines 4(b) and 4(i) by not constraining its model to preclude selection of new natural gas resources | The 2025 IRP included natural gas resource options, which had been excluded in the 2021 IRP and restricted in the 2023 IRP. |
| Docket No. 21-035-09, UPSC June 2, 2022 Order p. 9-18 | PacifiCorp will provide information to stakeholders three business days in advance of public meetings | PacifiCorp consistently provided meeting materials to stakeholders via email and public website postings within the parameters of this requirement. See Appendix C (Public Input). |
| Docket No. 90-2035-01 p. 33-37 | The Integrated Resource Plan will be used in rate cases to evaluate the performance of the utility and to review avoided cost calculations. | PacifiCorp is compliant with this standard. |
| Docket No. 23-035-10 p. 15 | For the 2025 IRP cycle, PacifiCorp shall:<br>1) incorporate all model inputs into the model by September 1, 2024; | Not applicable to the 2025 IRP.<br><br>This requirement was suspended on September 24, 2024 for the 2025 IRP cycle, which was scheduled and well under way by the time of the original Order. The 2025 IRP has been developed on its previously |

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| **Reference** | **Requirement or Recommendation** | **2025 IRP Approach** |
| | 2) reveal modeling results up to and including the ranking of the portfolios at a PIM to be held on or before October 15, 2024. If new model inputs cannot be incorporated into the model without jeopardizing compliance with this deadline, PacifiCorp must wait to incorporate the late-breaking data until the 2025 IRP Update;<br>3) hold a subsequent PIM to present updated modeling results and the preferred portfolios to stakeholders, by no later than November 15, 2024; and,<br>4) file a preliminary IRP with the PSC by January 1, 2025. | updated schedule which had already been compressed and adapted to allow for a draft filing, which was distributed on December 31, 2024.<br><br>Under this schedule, data was locked down at the end of September, and draft results provided in the December draft filing, with discussion of feedback scheduled for two public input meetings held January 22-23, 2025, and February 25-26, 2025. |
| Docket No. 23-035-10 IRP Timing Order | PacifiCorp shall not make changes to the modeling assumptions used to produce the modeling results it intends to disclose on January 1, 2025, after disclosure of those modeling results. Any new or changing model inputs that cannot be incorporated into the modeling results disclosed January 1, 2025, must wait to be incorporated into PacifiCorp's 2025 IRP Update. | This order requires that for Utah, subsequent corrections and updates are not available for further development of the IRP, and consequently the IRP filed in Utah will differ from the version files in other jurisdictions. Inputs that have remained under development include loads, stochastics, corrections to supply-side resource data and the Natrium commercial online date.<br><br>The Utah 2025 IRP includes three Utah-specific chapters to address the Order:<br>• Chapter 11 (Utah Executive Summary)<br>• Chapter 12 (Utah Model Results)<br>• Chapter 13 (Utah Action Plan) |
| Docket No. 23-035-10 p. 15 | Beginning with the 2027 IRP cycle and beyond, PacifiCorp shall:<br><br>1) prior to ranking resource portfolios, present indicative resource portfolios to stakeholders at a PIM at least five months before the planned filing date of any IRP. If new model inputs cannot be incorporated into the model without jeopardizing compliance with this deadline, PacifiCorp must wait to incorporate the late-breaking data until the subsequent IRP Update filing:<br>2) present updated modeling results, including final evaluations and preferred portfolio selections, to stakeholders at a PIM meeting to be held at least two months before the planned filing date of any IRP. | Not applicable to the 2025 IRP. |

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| **Reference** | **Requirement or Recommendation** | **2025 IRP Approach** |
| Docket UE-210829, Order 06 Appendix A: Full Multi-Party Settlement Agreement, p. 9 | Transparency Condition 1. PacifiCorp will provide a copy of its PLEXOS model database files in native file format upon request by any intervenor with a signed confidentiality agreement, subject to relevant and appropriate confidentiality concerns. The compressed version will include the PLEXOS database file (with a .xml extension) or the functional equivalent, and all data input files (with .csv extensions), organized using a structure that will allow a party knowledgeable in PLEXOS to load, execute, and run the Company's CEIP portfolio model via PLEXOS. Additionally, PacifiCorp will include a "readme" file with instructions for how interested parties that are knowledgeable in PLEXOS can load, execute, and run the compressed CEIP portfolio model using the PLEXOS long-term capacity expansion software. PacifiCorp will also file a version of the same PLEXOS input and output files in an easily accessible format, such as Excel. Due Date: 2025 CEIP. | Not due until the 2025 CEIP. However, PacifiCorp is streamlining the process to provide these materials and has confirmed with Energy Exemplar that a version of the .xml formatted database can be made available on a highly confidential basis in future filings. |
| Docket UE-210829, Order 06 Appendix A: Full Multi-Party Settlement Agreement, p. 10 | Transparency Condition 2. PacifiCorp will make a meaningful effort to review each workpaper file for sensitive commercial information and to the extent reasonable ensure that any non-confidential information within a workpaper designated as confidential is also provided in a non-confidential workpaper. With this understanding, PacifiCorp will not file with confidential designation any information that is not commercially sensitive, including (but not limited to) information filed with the Commission in other dockets without confidential designation, and information reported to the Commission or any other regulatory body that is reported without confidential designation. Due Date: 2025 CEIP. | Not due until the 2025 CEIP, however, PacifiCorp's 2025 IRP is committed to transparency and continues the commitments to provide an expanded set of public workpapers in which commercially sensitive data has either been aggregated or removed. |

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| **Reference** | **Requirement or Recommendation** | **2025 IRP Approach** |
| Docket UE-210829, Order 06 Appendix A: Full Multi-Party Settlement Agreement, p. 10 | Transparency Condition 3. PacifiCorp's workpaper index will include a parenthetical, naming convention, taxonomy, or other description that is intuitive and makes it easy to tell what is in each file and how one file connects with another. Due Date: 2025 CEIP.<br>Transparency Condition 5. PacifiCorp will include a read-me tab at the beginning of each summary report Excel workpaper that explains what information or data is in each subsequent tab, and PacifiCorp's workpaper index will crosswalk how that data flows through to other tabs and other workpapers (i.e., analytic files) that may depend on data from the given file. Due Date: 2025 CEIP. | Not due until the 2025 CEIP, however, the 2025 IRP meets these conditions. |
| Docket UE-210829, Order 06 Appendix A: Full Multi-Party Settlement Agreement, p. 10 | Transparency Condition 6. PacifiCorp will: (1) fund the purchase of four (4) full or partial licenses for Staff to use the PLEXOS model, including reasonable development, training, and support provided by Energy Exemplar to train Staff how contract negotiations with Energy Exemplar; and (3) provide live PLEXOS support to Staff regarding PacifiCorp's CEIP modeling, not to exceed 4 hours each month, that includes but is not limited to, live demonstration of portfolio runs, and review of file inputs for all relevant models used in PacifiCorp's CEIP (if relying on screen shots of PLEXOS files or email question-and-answer support is not sufficient). This support provided by PacifiCorp shall not include general PLEXOS development, training, or support. The parties do not object to the Company seeking full cost-recovery of these PLEXOS-related licensing costs, expenses, and support. Due Date: Contract discussions to begin within 60 days of the date of the Commission's final order in this case. | PacifiCorp has entered into an agreement with Washington Commission staff and Energy Exemplar to fulfill a modified version of this condition. |
| Docket UE-210829, Order 06 Appendix A: Full Multi-Party Settlement Agreement, p. 10 | Transparency Condition 7. As part of its CEIP workpapers, PacifiCorp will provide a list of all the resources (including generating units, conservation, demand response, and any other resource types) that it allocates to serve Washington customers throughout that CEIP, the fuel source for each resource, and a yearly breakdown of the forecasted MWh allocated to Washington from that resource. Due date: 2024 Filing and 2025 CEIP. | Not due until the 2025 CEIP. |
| Docket UE-210829, Order 06 Appendix A: Full Multi- | Incremental Cost Condition 2. The workpapers that PacifiCorp supplies to support its incremental cost calculation will list all | Not due until the 2025 CEIP. |

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| **Reference** | **Requirement or Recommendation** | **2025 IRP Approach** |
| Party Settlement Agreement, p. 11 | investments and expenses that the utility plans to make during the period in order to comply with the requirements of RCW 19.405.040 and 19.405.050, and demonstrate that those investments and expenses are directly attributable to actions necessary to comply with, or make progress towards, the same RCW provisions. Due Date: 2025 CEIP. | |
| Docket UE-210829, Order 06 Appendix A: Full Multi-Party Settlement Agreement, p. 11 | Incremental Cost Condition 3. PacifiCorp will participate in any further discussions and/or workshops regarding incremental cost calculations and incorporate any changes necessary to their methodology. Due Date: As applicable. | PacifiCorp is not aware of additional discussions or workshops applicable to this requirement. |
| Docket UE-210829, Order 06 Appendix A: Full Multi-Party Settlement Agreement, p. 12 | Interim Target Condition 3. PacifiCorp will optimize its resource portfolio at lowest reasonable cost, when accounting for risk, using its long-term capacity expansion portfolio optimization software (PLEXOS) to model its CEIP targets for the entire compliance period through 2045, and not linearly interpolate its 2041-2045 targets from its modeling of the 2021-2040 time period. Due Date: 2025 CEIP. | Not due until the 2025 CEIP, however the 2025 IRP meets this requirement by running 21-year models. |
| Docket UE-210829, Order 06 Appendix A: Full Multi-Party Settlement Agreement, p. 12 | Interim Target Condition 4. In future CEIPs, PacifiCorp will continue to include descriptions of quantitative (i.e., cost based) and qualitative (e.g., equity considerations) analyses that support interim targets to comply with CETA's 2030 and 2045 clean energy standards. Due Date: 2025 CEIP. | Not due until the 2025 CEIP, however this condition is met by the IRP analysis and information provided in Appendix O regarding the CEAP, including specific discussion of energy equity. |
| Docket UE-210829, Order 06 Appendix A: Full Multi-Party Settlement Agreement, p. 12 | Interim Target Condition 5. In its 2025 CEIP, PacifiCorp will continue to advance the application of Non-Energy Impacts and Customer Benefit Indicators to all resource and program selections in determining its Washington resource strategy and will incorporate any guidance given by the Commission on how to best utilize CBIs in CEIP planning and evaluation. PacifiCorp agrees to engage and consult with its applicable advisory groups (including the IRP, demand-side management, and Equity advisory groups) regarding an appropriate methodology for including NEIs and CBIs in its resource selection. Due Date: 2025 CEIP. | Not due until the 2025 CEIP. |
| Docket UE-210829, Order 06 Appendix A: Full Multi- | Interim Target Condition 6. PacifiCorp will update its CEIP with accurate and up-to-date cost information for all its specific actions, | Not due until the 2025 CEIP, however the 2025 IRP provides sensitivities regarding high and low potential for IRA impacts. See |

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| **Reference** | **Requirement or Recommendation** | **2025 IRP Approach** |
| Party Settlement Agreement, p. 12 | including incorporating applicable provisions of the Inflation Reduction Act (IRA). At a minimum, PacifiCorp should incorporate, from the IRA, assumptions pertaining to bonus tax credits for replacement generation in "energy communities," the availability of low-cost financing from the U.S. Department of Energy under the Energy Infrastructure Reinvestment (EIR) program, and make adjustments to the Company's load forecast to account for the Greenhouse Gas Reduction Fund and the High-Efficiency Electric Home Rebate Program, if warranted. Due Date: 2025 CEIP. | Chapter 8 and 9. |
| Docket UE-210829, Order 06 Appendix A: Full Multi-Party Settlement Agreement, p. 14 | Miscellaneous Condition 4. PacifiCorp will evaluate methods to improve the alignment of the Company's planning and procurement processes and provide a narrative description of how it plans to align the planning and procurement processes in the 2025 CEIP. Due Date: 2025 CEIP. | Not due until the 2025 CEIP. |
| Docket UE-210829, Order 06 Appendix A: Full Multi-Party Settlement Agreement, p. 14 | Miscellaneous Condition 5. PacifiCorp will incorporate its ongoing climate analysis into the 2025 CEIP and future CEIPs. Due Date: 2025 CEIP. | Not due until the 2025 CEIP, however the 2025 IRP meets this condition with the inclusion of climate change in its base assumptions. |
| Docket UE-210829, Order 06 Appendix A: Full Multi-Party Settlement Agreement, p. 14 | Miscellaneous Condition 6. PacifiCorp will prepare a sensitivity PLEXOS model run that excludes non-commercialized resources from the candidate resource list and relies upon clean resources, including offshore wind, demand response, enhanced geothermal, iron-air batteries or similar long duration storage, and high-capacity factor solar plus storage (among other resources), to meet identified reliability gaps. Due Date: 2025 CEIP. | Not due until the 2025 CEIP, however the 2025 IRP meets this condition with its 'no nuclear' and 'no future technology' variants, as described in Chapter 8. |
| Docket UE-210830, Order 01, Attachment A, condition 11a | During CPA development, demonstrate progress towards identifying, researching, and properly valuing NEIs. Docket UE-210830, Order 01, Attachment A, condition 11a | . <br>Starting with the 2021 IRP cycle, PacifiCorp has been discussing with the DSM Advisory Group and EAG its research, findings, and ongoing progress with NEI. Since that time, PacifiCorp has also been incorporating NEIs into planning: specifically, the 2023 and 2025 CPAs have both included measure-specific NEI adjustments. Please see the CPA Appendix E for further information. |
| WUTC v. Cascade Natural | Commission issues preliminary guidance on equity at a high-level, | PacifiCorp discusses the four tenets of energy justice in its |

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| **Reference** | **Requirement or Recommendation** | **2025 IRP Approach** |
| Gas Corporation, Docket UG-210755 Order 09 (August 23, 2022) | clarifying definitions and expectations that should be applied to utility planning and rate making. Integral to this work is the concept of energy justice and its core tenets to advance the goal of achieving equity in Washington energy regulation. | Appendix O: Clean Energy Action Plan and offers a qualitative discussion of how these four tenets are applied and exemplified by ongoing PacifiCorp actions. |

| B.2(e) - Wyoming | | |
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| **Reference** | **Requirement or Recommendation** | **2025 IRP Approach** |
| Order, Docket No. 90000-144-XI-19 (Record No. 15280) | 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 using environmental investments or costs only required by current law. For example, the reference case will not include an estimate or assumed price or cost for carbon emissions absent an existing legal requirement. | PacifiCorp has complied with this requirement by the inclusion of the "Business as Usual" sensitivity. Additional information on the specified reference case can be found in Chapter 8 and 9. |
| Order, Docket No. 90000-144-XI-19 (Record No. 15280) | Conduct a more extensive analysis of the impact of alternative price-policy scenarios on the resource plan. | The impact of price-policy scenarios on the resource plan is summarized in Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection). |
| Order, Docket No. 90000-144-XI-19 (Record No. 15280) | Conduct a sensitivity analysis on top performing portfolio cases and the reference case. | PacifiCorp has complied with this requirement. All candidate portfolios are evaluated under other price-policies. Additional information on sensitivity analyses can be found within Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection). |
| Order, Docket No. 90000-144-XI-19 (Record No. 15280) | Demonstrate rate impacts over the planning period between preferred portfolio and the reference case. | The 2025 IRP includes comparative analysis in Chapter 9 for all cases including the Business as Usual reference case and the preferred portfolio, using present value revenue requirement as indicative of rate pressure. |

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| **Reference** | **Requirement or Recommendation** | **2025 IRP Approach** |
| Order, Docket No. 90000-144-XI-19 (Record No. 15280) | Investigate alternative methodologies to integrate different reliability analyses including regional analysis of resource adequacy; analysis of power flow issues caused by retiring coal units; study of potential weather-related outages on intermittent generation; and an analysis of wildfire risk. | Chapter 5 (Reliability and Resiliency) includes regional analyses of resource adequacy, a discussion of power flow issues caused by baseload resource retirements and how PacifiCorp Transmission is planning for those retirements, an assessment of weather-related outages, and a discussion of wildfire risk and mitigation. |
| Order, Docket No. 90000-144-XI-19 (Record No. 15280) | Include additional analysis on operational experience, if any, with battery acquisition and operations and include a review of capabilities learned from other utilities. | PacifiCorp has included a description of procurement and operational experience since the previous IRP with battery acquisition and operations as part of Chapter 7 (Resource Options). |
| Order, Docket No. 90000-144-XI-19 (Record No. 15280) | Include an analysis that demonstrates how the Company will maximize the use of dispatchable and reliable low-carbon electricity pursuant to HB200. | PacifiCorp has included Carbon Capture and Sequestration analysis within the portfolio modeling process. Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection Results)5 |
| Order, Docket No. 90000-144-XI-19 (Record No. 15280) | Incorporate an analysis of any agreed upon change to the MSP and to the extent there are outstanding material disagreements regarding cost allocation at the time of filing, quantify those risks and potential impact to Wyoming ratepayers. | 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 and implementation in 2025. PacifiCorp addresses the multi-state process in Chapter 3. |
| Order, Docket No. 90000-144-XI-19 (Record No. 15280) | Include a broader analysis of all generation types including nuclear and natural gas. | PacifiCorp has continued to expand and update the generation types included in the supply-side table as part of the 2025 IRP. Advanced nuclear and natural gas resources have both been updated and analyzed in all studies in the 2025 IRP (unless excluded to develop a specific sensitivity or variant). New to the 2025 IRP is the combined gas plant with electrolyzer option, and a renewable peaking resource assumed to be fueled by renewable biodiesel. |
| Order, Docket No. 90000-144-XI-19 (Record No. 15280) | Include a narrative discussing impacts and regulatory framework for renewable generation. | PacifiCorp has added this narrative analysis to the Planning Environment discussion in Chapter 3 (Planning Environment). |
| Order, Docket No. 90000-144-XI-19 (Record No. 15280) | Include an acknowledgement that each of these requirements are Addressed in the 2025 IRP to ensure compliance. | PacifiCorp acknowledges these requirements and has addressed each within the 2025 IRP. |

<table>
<tr><th colspan="3">B.2(f) - California</th></tr>
<tr><th>Reference</th><th>Requirement or Recommendation</th><th>2025 IRP Approach</th></tr>
<tr><td>D.18-02-018<br><br>D.22-02-004<br><br>Public Utilities Code §§ 399.13(a)(7), 454.5, 454.52</td><td>Addressing Disadvantaged Communities<br><br>Provide supplemental information about disadvantaged communities, including “a demonstration of how disadvantaged communities were considered.” (D.18-02-018, p. 135.)<br><br>“PacifiCorp is required to supplement its multi-state IRP with … specific information on … a separate demonstration that satisfies the requirements for disadvantaged communities.” (D.22-02-004, p. 22.)<br><br>“At a minimum, all LSEs shall provide the following information in their IRPs:<br>i. A description of which disadvantaged communities, if any, it serves (LSEs will be expected to make the determination of what is considered “disadvantaged” every two years);<br>ii. What current and planned LSE activities/programs, if any, impact disadvantaged communities; and<br>iii. A qualitative description of the demographics of the customers it serves and how it is currently addressing or plans to comply with the requirement to minimize air pollutants.” (D.18-02-018, p. 68.)<br><br>If we wish to provide additional information, we can address how PacifiCorp is:<br>• strengthening “the diversity, sustainability, and resilience of the bulk transmission and distribution systems, and local communities.” (D.18-02-018, p. 66; Pub. Util. Code § 454.52.)<br>• minimizing “localized air pollutants and other greenhouse gas emissions, with early priority on disadvantaged communities.” (D.18-02-018, p. 66; Pub. Util. Code § 454.52.)<br>• giving “preference to renewable energy projects that</td><td>PacifiCorp serves fewer than 50,000 customers in mostly rural northern California, with a significant number of customers on energy assistance programs. PacifiCorp’s California customers are geographically-dispersed, with approximately four customers per square mile.[10]<br><br>PacifiCorp is committed to affordability to protect disadvantaged communities. In PacifiCorp’s most recent general rate case filed with the California Public Utilities Commission, the company requested recovery of costs associated with the addition of investments in renewable generation resources. Those resources reduce overall emissions and provide zero-fuel cost energy and production tax credits that benefit our customers. PacifiCorp also proposed an increase to its California Alternative Rates for Energy discount from 20 percent to 25 percent, new time varying rate options, and paperless bill credit, among other changes, to support customers during increased costs for wholesale energy and wildfire mitigation.<br><br>In 2024, PacifiCorp transitioned its Home Energy Savings residential energy efficiency program from a resource acquisition program to an equity program targeting Hard-to-Reach and Tribal customers. In addition, PacifiCorp filed an advice filing requesting approval to offer Home Energy Reports as an equity program targeting only Hard-to-Reach and Tribal customers.<br><br>PacifiCorp IRP identifies increased investment in non-emitting resources to service all of its customers. Further, PacifiCorp does not own or operate any thermal generation in California that would negatively impact communities in the California service area.</td></tr>
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[10] SB 535 Disadvantaged Communities | OEHHA (ca.gov)

| B.2(f) - California | | |
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| **Reference** | **Requirement or Recommendation** | **2025 IRP Approach** |
| | provide environmental and economic benefits to communities afflicted with poverty or high unemployment, or that suffer from high emission levels of toxic air contaminants, criteria pollutants, and greenhouse gases." (D.18-02-018, p. 67; Pub. Util. Code § 399.13(a)(7).)<br><br>In soliciting bids for new gas-fired generating units, PacifiCorp should "actively seek bids for resources that are not gas-fired generating units located in communities that suffer from cumulative pollution burdens, including, but no [sic] limited to, high emission levels of toxic air contaminants, criteria air pollutants, and greenhouse gases." (D.18-02-018, p. 67; Pub. Util. Code § 454.5(b)(9)(D).) | |
| D.19-04-040<br><br>D.22-02-004<br><br>ALJ Ruling Finalizing Load Forecasts and Greenhouse Gas Emissions Benchmarks for 2022 Integrated Resource Plan Filings | GHG Emissions Accounting<br><br>"PacifiCorp should consult with Commission staff and describe an alternative [to the CNS/CSP Calculator] methodology that addresses its share of the 2030 GHG emissions reduction responsibility." (D.19-04-040, p. 74.)<br><br>"PacifiCorp is required to supplement its multi-state IRP with … specific information on … another (non-CSP calculator) method to fulfill requirements that would otherwise have required the CSP tool and justification for the choice." (D.22-02-004, p. 22.)<br><br>PacifiCorp's GHG benchmarks are available here: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2022-irp-cycle-events-and-materials/2022-final-ghg-emission-benchmarks-for-lses_public.xlsx | PacifiCorp met with CPUC staff in 2020 and agreed upon an alternative methodology to address GHG benchmarks using the company's IRP. This methodology has been used and approved in subsequent IRP filings.<br><br>PacifiCorp's IRP supplement will include the results of the emissions forecast in California, relative to the Company's GHG Benchmark. |

### Table B.3 – Oregon Public Utility Commission IRP Standards and Guidelines

| B.3 - Oregon Standards and Guidelines | | |
|---|---|---|
| **1. Substantive Requirements** | | |
| **Reference** | **Requirement** | **2025 IRP Approach** |
| 1.a.1 | All resources must be evaluated on a consistent and comparable basis:<br>All known resources for meeting the utility's load should be considered, including supply- side options which focus on the generation, purchase and transmission of power – or gas purchases, transportation, and storage – and demand-side options which focus on conservation and demand response. | PacifiCorp considered a wide range of resources including renewables, demand-side management, energy storage, power purchases, thermal resources, and transmission. Chapter 4 (Transmission Planning), Chapter 7 (Resource Options), and Chapter 8 (Modeling and Portfolio Evaluation) document how PacifiCorp developed these resources and modeled them in its portfolio analysis. All these resources were established as resource options in the company's capacity expansion optimization model, PLEXOS, and selected by the model based on load requirements, relative economics, resource size, availability dates, and other factors. The supply-side resources were presented and discussed at five public input meetings at various stages of development spanning nine months, and public materials were provided online for examination and discussion. |
| 1.a.2 | All resources must be evaluated on a consistent and comparable basis:<br>Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling. | All portfolios developed with PLEXOS were subjected to stochastic representation. These portfolios contained a variety of resource types with different fuel types (coal, gas, biomass, nuclear fuel, "no fuel" renewables), lead-times (ranging from front office transactions to nuclear plants), in-service dates, operational lives, and locations. See Chapters 7-9, and Appendix I and Appendix J. |
| 1.a.3 | All resources must be evaluated on a consistent and comparable basis:<br>Consistent assumptions and methods should be used for evaluation of all resources. | PacifiCorp fully complies with this requirement. The company developed generic supply-side resource attributes based on a consistent characterization methodology. For Supply Side Resources (SSR's), the National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB) was used as much as possible to maintain consistency. Most of the supply-side resource options rely on the ATB and Energy Information Agency (EIA) reports. Some SSR's contained in the SSR tables are not listed in the ATB, but were developed through other reports, conversations with industry experts, developers and original equipment manufacturers (OEM's). For demand-side resources, the company used the Applied Energy Group's supply curve data developed for this IRP for representation of DSM resources. The study was based on a consistently applied methodology for determining technical, market, and achievable DSM potentials. All portfolio resources were evaluated using the same sets of price and load forecast inputs. These inputs are documented in Chapter 6 (Load and Resource Balance), Chapter 7 (Resource Options), and Chapter 8 (Modeling and Portfolio Evaluation) as well as Appendix D (Demand-Side Management). |

| B.3 - Oregon Standards and Guidelines | | |
|---|---|---|
| **1. Substantive Requirements** | | |
| **Reference** | **Requirement** | **2025 IRP Approach** |
| 1.a.4 | All resources must be evaluated on a consistent and comparable basis: The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs. | PacifiCorp applied its nominal after-tax WACC of 6.77 percent to discount all cost streams. For construction periods of supply side resources, allowance for funds used during construction (AFUDC), capital surcharge, and property taxes were applied per standard confidential Company accounting rules. Care was taken to ensure these costs were not double counted (by any other assumptions) in the underlying assumptions. |
| 1.b.1 | Risk and uncertainty must be considered: At a minimum, utilities should address the following sources of risk and uncertainty:<br>1. Electric utilities: load requirements, hydroelectric generation, plant forced outages, fuel prices, electricity prices, and costs to comply with any regulation of greenhouse gas emissions. | Each of the sources of risk identified in this guideline is treated as a stochastic variable in PacifiCorp's production cost simulation apart from CO2 emission compliance costs, which are treated as a scenario risk and evaluated as part of a CO2 price assumption and a no CO2, a high CO2, and a social cost of carbon price-policy scenario for specific studies. See Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection Results). |
| 1.b.2 | Risk and uncertainty must be considered: Utilities should identify in their plans any additional sources of risk and uncertainty. | Resource risk mitigation is discussed in Chapter 10 (Action Plan). Regulatory and financial risks associated with resource and transmission investments are highlighted in several areas in the IRP document, including Chapter 3 (Planning Environment), Chapter 4 (Transmission), Chapter 8 (Modeling and Portfolio Evaluation), and Chapter 9 (Modeling and Portfolio Selection Results). |
| 1.c | The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers ("best cost/risk portfolio"). | PacifiCorp evaluated cost/risk tradeoffs for each of the portfolios considered as a candidate to be the preferred portfolio. See Chapter 9 (Modeling and Portfolio Selection Results), Chapter 10 (Action Plan), and Appendix I (Capacity Expansion Results) a for the company's portfolio cost/risk analysis and determination of the preferred portfolio. See Appendix H (Stochastic Methodology and Simulation) for a detailed discussion of the historical data used to construct 18 separate stochastic datasets and the performance of every candidate portfolio under a range of possible conditions. |
| 1.c.1 | The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource. | PacifiCorp used a 21-year study period (2025-2045) for portfolio modeling, and a real levelized revenue requirement methodology for treatment of end effects. |

| B.3 - Oregon Standards and Guidelines | | |
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| **1. Substantive Requirements** | | |
| **Reference** | **Requirement** | **2025 IRP Approach** |
| 1.c.2 | Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all long-lived resources such as power plants, gas storage facilities, and pipelines, as well as all short- lived resources such as gas supply and short- term power purchases. | Chapter 8 (Modeling and Portfolio Evaluation) provides a description of the PVRR methodology. |
| 1.c.3.1 | To address risk, the plan should include, at a minimum:<br>1. Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes. | PacifiCorp compares the average production costs across a random sample of stochastic runs to the production costs in normalized runs as the measure of cost variability. For the severity of bad outcomes, the company calculates the 95th percentile PVRR across the random sample of stochastic runs and takes 5% of the difference between this PVRR and the PVRR from the normalized run and adds it to the risk adjustment calculated for each variant portfolio. |
| 1.c.3.2 | To address risk, the plan should include, at a minimum:<br>2. Discussion of the proposed use and impact on costs and risks of physical and financial hedging. | A discussion on hedging is provided in Chapter 10 (Action Plan). |
| 1.c.4 | The utility should explain in its plan how its resource choices appropriately balance cost and risk. | Chapter 9 (Modeling and Portfolio Selection Results) summarizes the results of PacifiCorp's cost/risk tradeoff analysis and describes what criteria the company used to determine the best cost/risk portfolios and the preferred portfolio. |
| 1.d | The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies. | PacifiCorp considered both current and potential state and federal energy/pollutant emission policies in portfolio modeling. Chapter 7 (Modeling and Portfolio Evaluation) describes the decision process used to derive portfolios, which includes consideration of state and federal resource policies and regulations that are summarized in Chapter 3 (Planning Environment). Chapter 9 (Modeling and Portfolio Selection Results) provides the results. Chapter 10 (Action Plan) presents an acquisition path analysis that describes resource strategies based on regulatory trigger events. |

| B.3 - Oregon Standards and Guidelines | | |
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| **2. Procedural Requirements** | | |
| **Reference** | **Requirement** | **2025 IRP Approach** |
| 2.a | The public, which includes other utilities, should be allowed significant involvement in the preparation of the IRP. Involvement includes opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make relevant inquiries of the utility formulating the plan. Disputes about whether information requests are relevant or unreasonably burdensome, or whether a utility is being properly responsive, may be submitted to the Oregon PUC for resolution. | PacifiCorp fully complies with this requirement. Appendix C (Public Input) provides an overview of the public input process, all public-input meetings held for the 2025 IRP, and summarizes public input received throughout the 2025 IRP cycle. PacifiCorp also made use of a Stakeholder Feedback Form for stakeholders to provide comments and offer suggestions. Stakeholder Feedback Forms along with responses and the public-input meeting presentations are included in Appendix M, and also publicly available on PacifiCorp's webpage at: www.pacificorp.com/energy/integrated-resource-plan.html. |
| 2.b | While confidential information must be protected, the utility should make public, in its plan, any non-confidential information that is relevant to its resource evaluation and action plan. Confidential information may be protected through use of a protective order, through aggregation or shielding of data, or through any other mechanism approved by the Oregon PUC. | 2025 IRP Volumes I and II provide non-confidential information used for portfolio evaluation, as well as other data requested by stakeholders. PacifiCorp also provided stakeholders with non-confidential information to support public meeting discussions via email and in response to Stakeholder Feedback Forms. Workpapers will be available with public data. Additionally, workpapers with confidential data will be provided to appropriate parties through use of a general protective order. |
| 2.c | The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Oregon PUC. | PacifiCorp distributed draft IRP materials for external review throughout the process prior to each of the public input meetings and solicited/and received feedback at various times when developing the 2025 IRP. The materials shared with stakeholders at these meetings, outlined in Appendix C and Appendix M, is aligned with the discussion of materials presented in Volumes I and II of the 2025 IRP report.<br><br>PacifiCorp requested and responded to comments from stakeholders when establishing modeling assumptions and throughout its portfolio-development process and sensitivity definitions, and in the 2025 IRP footnoted stakeholder feedback forms to relevant topics throughout the IRP document. |

| B.3 - Oregon Standards and Guidelines | | |
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| **3. Plan Filing, Review, and Updates** | | |
| **Reference** | **Requirement** | **2025 IRP Approach** |
| 3.a | A utility must file an IRP within two years of its previous IRP acknowledgment order. If the utility does not intend to take any significant resource action for at least two years after its next IRP is due, the utility may request an extension of its filing date from the Oregon PUC. | The 2025 IRP complies with this requirement. |
| 3.b | The utility must present the results of its filed plan to the Oregon PUC at a public meeting prior to the deadline for written public comment. | This activity will be conducted following the filing of this IRP. |
| 3.c | Commission staff and parties should complete their comments and recommendations within six months of IRP filing. | This activity will be conducted following the filing of this IRP. |
| 3.d | The Commission will consider comments and recommendations on a utility's plan at a public meeting before issuing an order on acknowledgment. The Commission may provide the utility an opportunity to revise the IRP before issuing an acknowledgment order. | This activity will be conducted following the filing of this IRP. |
| 3.e | The Commission may provide direction to a utility regarding any additional analyses or actions that the utility should undertake in its next IRP. | Not applicable. |
| 3.f | (a) Each energy utility must submit an annual update on its most recently acknowledged IRP. The update is due on or before the acknowledgment order anniversary date. Once a utility anticipates a significant deviation from its acknowledged IRP, it must file an update with the Oregon PUC, unless the utility is within six months of filing its next IRP. The utility must summarize the update at an Oregon PUC public meeting. The utility may request acknowledgment of changes in proposed actions identified in an update. | Not applicable to this filing; this activity will be conducted following the filing of this IRP. |

| B.3 - Oregon Standards and Guidelines | | |
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| **3. Plan Filing, Review, and Updates** | | |
| **Reference** | **Requirement** | **2025 IRP Approach** |
| 3.g | Unless the utility requests acknowledgment of changes in proposed actions, the annual update is an informational filing that:<br>• Describes what actions the utility has taken to implement the plan;<br>• Provides an assessment of what has changed since the acknowledgment order that affects the action plan to select best portfolio of resources, including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource acquisitions, resource costs, and transmission availability; and<br>• Justifies any deviations from the acknowledged action plan. | Not applicable to this filing; this activity will be conducted following the filing of this IRP. |

| B.3 - Oregon Standards and Guidelines | | |
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| **4. Plan Components** | | |
| **Reference** | **Requirement** | **2025 IRP Approach** |
| 4.a | An explanation of how the utility met each of the substantive and procedural requirements. | The intent of this table is to comply with this guideline. |
| 4.b | Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions. | PacifiCorp developed low, high, and extreme peak temperature (one-in-twenty probability) load growth forecasts for scenario analysis using the PLEXOS model. The Company developed factors incorporating the percentage difference between daily average actual load and monthly average weather-normalized load for each state and included these factors in stochastic analysis. See Chapters 6 (Load and Resource Balance), Chapter 8 (Modeling and Portfolio Evaluation), Appendix A (Load Forecast), and Appendix H (Stochastics). |
| 4.c | For electric utilities, a determination of the levels of peaking capacity and energy capability expected for each year of the plan, given existing resources; identification of capacity and energy needed to bridge the gap between expected loads and resources; modeling of all existing transmission rights, as well as future transmission additions associated with the resource portfolios tested. | See Chapter 6 (Load and Resource Balance) for details on annual capacity and energy balances. Existing transmission rights are reflected in the IRP model topologies. Future transmission additions used in analyzing portfolios are summarized in Chapter 4 (Transmission) and Chapter 8 (Modeling and Portfolio Evaluation). |
| 4.d | For gas utilities only. | Not applicable. |

| B.3 - Oregon Standards and Guidelines | | |
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| **4. Plan Components** | | |
| **Reference** | **Requirement** | **2025 IRP Approach** |
| 4.e | Identification and estimated costs of all supply-side and demand side resource options, considering anticipated advances in technology. | Chapter 7 (Resource Options) identifies the resources included in this IRP and provides their detailed cost and performance attributes. Additional information on energy efficiency resource characteristics is available in Appendix D (Demand-Side Management Resources) referencing additional information on PacifiCorp's IRP website. |
| 4.f | Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs. | All portfolios incorporate planning reserve margins modeled after the Western Resource Adequacy Program (WRAP) specifications. The cost-risk tradeoffs of providing reliable service are examined in stochastic analysis, where portfolios are evaluated under various load and resource conditions and ranked based on their performance in these conditions. Refer to Appendix H (Stochastics) for details of this stochastic analysis. |
| 4.g | Identification of key assumptions about the future (e.g., fuel prices and environmental compliance costs) and alternative scenarios considered. | Chapter 8 (Modeling and Portfolio Evaluation) describes the key assumptions and alternative scenarios used in this IRP. Appendix I (Capacity Expansion Results) includes summaries of assumptions used for each case definition analyzed in the 2025 IRP. |
| 4.h | Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations - system-wide or delivered to a specific portion of the system. | This IRP documents the development and results of portfolios designed to determine resource selection under a variety of input assumptions in Chapters 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection Results). |
| 4.i | Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties. | Chapter 9 (Modeling and Portfolio Selection Results) incorporates the stochastic portfolio modeling results as described in Chapter 8 (Modeling and Portfolio Evaluation) and describes portfolio attributes that explain relative differences in cost and risk performance. |
| 4.j | Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results. | Chapter 9 (Modeling and Portfolio Selection Results) provides tables and charts with performance measure results, including rank ordering. |
| 4.k | Analysis of the uncertainties associated with each portfolio evaluated. | See responses to 1.b.1 and 1.b.2 above. |
| 4.l | Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers. | See 1.c above. |
| 4.m | Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation. | This IRP is designed to avoid inconsistencies with state and federal energy policies and therefore none are currently identified. |

| B.3 - Oregon Standards and Guidelines | | |
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| 4. Plan Components | | |
| Reference | Requirement | 2025 IRP Approach |
| 4.n | An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing. | Chapter 10 (Action Plan) presents the 2025 IRP action plan. |

| B.3 - Oregon Standards and Guidelines | | |
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| 5. Transmission | | |
| Reference | Requirement | 2025 IRP Approach |
| 5 | Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving reliability. | Resource and transmission costs and attributes are endogenously optimized as part of PLEXOS functionality. Where new resources would require additional transmission facilities, the associated costs are factored into the analysis. Fuel transportation costs are also factored into resource costs. Also, modeling of small-scale renewable resources for both the IRP and CEP assumes there are no accompanying transmission requirements, providing an additional opportunity to evaluate transmission avoidance beyond the native core functionality of the PLEXOS model. See Chapter 4 (Transmission), Chapter 7 (Resource Options), and Chapter 8 (Modeling and Portfolio Evaluation). |

| B.3 - Oregon Standards and Guidelines | | |
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| 6. Conservation | | |
| Reference | Requirement | 2025 IRP Approach |
| 6.a | Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory. | PacifiCorp's conservation potential study is available on the company's webpage, and the most recent results from the conservation potential assessment have been incorporated into the IRP modeling process. |
| 6.b | To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets. | PacifiCorp's energy efficiency supply curves incorporate Oregon resource potential. Oregon potential estimates were provided by the Energy Trust of Oregon. See the demand-side resource section in Chapter 7 (Resource Options), the results in Chapter 9 (Modeling and Portfolio Selection Results), the targeted amounts in Chapter 10 (Action Plan) and the implementation steps outlined in Appendix D (DSM Resources. |

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| 6.c | To the extent that an outside party administers conservation programs in a utility's service territory at a level of funding that is beyond the utility's control, the utility should:<br>1. Determine the amount of conservation resources in the best cost/risk portfolio without regard to any limits on funding of conservation programs; and<br>2. Identify the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition. | See the response for 6.b above. |

| B.3 - Oregon Standards and Guidelines | | |
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| **7. Demand Response** | | |
| **Reference** | **Requirement** | **2025 IRP Approach** |
| 7 | Plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity, and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities). | PacifiCorp evaluated demand response resources (DSM) on a consistent basis with other resources. |

| B.3 - Oregon Standards and Guidelines | | |
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| **8. Environmental Costs** | | |
| **Reference** | **Requirement** | **2025 IRP Approach** |
| 8.b | Testing alternative portfolios against the compliance scenarios: The utility should estimate, under each of the compliance scenarios, the present value revenue requirement (PVRR) costs and risk measures, over at least 20 years, for a set of reasonable alternative portfolios from which the preferred portfolio is selected. The utility should incorporate end-effect considerations in the analyses to allow for comparisons of portfolios containing resources with economic or physical lives that extend beyond the planning period. The utility should also modify | Chapter 9 (Modeling and Portfolio Selection Results) provides the risk adjustments calculated for each variant portfolio. Chapter 9 also reports PVRRs for each portfolio that incorporate end-effect considerations to forecast streams of revenues and costs that occur outside the 21-year horizon.<br><br>Early retirement and gas conversion alternatives to coal unit environmental investments were considered in the development of all resource portfolios. A range of compliance scenarios was also considered, with implications on the allowed lifetime of thermal resources in those scenarios. |

| B.3 - Oregon Standards and Guidelines | | |
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| **8. Environmental Costs** | | |
| **Reference** | **Requirement** | **2025 IRP Approach** |
| | projected lifetimes as necessary to be consistent with the compliance scenario under analysis. In addition, the utility should include, if material, sensitivity analyses on a range of reasonably possible regulatory futures for nitrogen oxides, sulfur oxides, and mercury to further inform the preferred portfolio selection. | |
| 8.c | Trigger point analysis: The utility should identify at least one CO2 compliance "turning point" scenario, which, if anticipated now, would lead to, or "trigger" the selection of a portfolio of resources that is substantially different from the preferred portfolio. The utility should develop a substitute portfolio appropriate for this trigger-point scenario and compare the substitute portfolio's expected cost and risk performance to that of the preferred portfolio – under the base case and each of the above CO2 compliance scenarios. The utility should provide its assessment of whether a CO2 regulatory future that is equally or more stringent that the identified trigger point will be mandated. | See Chapter 8 (Modeling and Portfolio Evaluation) for a description of initial portfolio development definitions. Comparative analysis of these case results is included in Chapter 9 (Modeling and Portfolio Selection Results). Also see Appendix P for additional description of these varying $CO_2$ futures. |
| 8.d | Oregon compliance portfolio: If none of the above portfolios is consistent with Oregon energy policies (including state goals for reducing greenhouse gas emissions) as those policies are applied to the utility, the utility should construct the best cost/risk portfolio that achieves that consistency, present its cost and risk parameters, and compare it to those in the preferred and alternative portfolios. | The 2025 IRP preferred portfolio presents a path that is compliant with all Oregon state requirements, including HB 2021 greenhouse gas emissions standards. For more in-depth discussion on Oregon compliance, see Appendix P: Oregon Clean Energy Plan Update. |

| B.3 - Oregon Standards and Guidelines | | |
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| 9. Direct Access Loads | | |
| Reference | Requirement | 2025 IRP Approach |
| 9 | An electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier. | Oregon Docket UE 267 established a long-term opt-out option for eligible PacifiCorp customers. Going forward PacifiCorp will cease planning for customers who elect direct-access service on a long-term basis (i.e. five-year opt out customers). |

| B.3 - Oregon Standards and Guidelines | | |
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| 10. Multi-state Utilities | | |
| Reference | Requirement | 2025 IRP Approach |
| 10 | Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated system basis that achieves a best cost/risk portfolio for all their retail customers. | The 2025 IRP conforms to the multi-state planning approach as stated in Chapter 2 (Introduction) under the section "The Role of PacifiCorp's Integrated Resource Planning". The company notes the challenges in complying with multi-state integrated planning given differing state energy policies and resource preferences. |

| B.3 - Oregon Standards and Guidelines | | |
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| **11. Reliability** | | |
| **Reference** | **Requirement** | **2025 IRP Approach** |
| 11 | Electric utilities should analyze reliability within the risk modeling of the actual portfolios being considered. Loss of load probability, expected planning reserve margin, and expected and worst-case unserved energy should be determined by year for top-performing portfolios. Natural gas utilities should analyze, on an integrated basis, gas supply, transportation, and storage, along with demand-side resources, to reliably meet peak, swing, and base-load system requirements.<br>Electric and natural gas utility plans should demonstrate that the utility's chosen portfolio achieves its stated reliability, cost and risk objectives. | See the response to 1.c.3.1 above. Chapter 9 (Modeling and Portfolio Selection Results) walks through the role of reliability, cost, and risk measures in determining the preferred portfolio. All portfolios included planning reserve margins modeled after the WRAP specifications. The performance of variant portfolios under adverse conditions was evaluated in stochastic analysis. Refer to Appendix H for details of the stochastic analysis. |

| B.3 - Oregon Standards and Guidelines | | |
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| **12. Distributed Generation** | | |
| **Reference** | **Requirement** | **2025 IRP Approach** |
| 12 | Electric utilities should evaluate distributed generation technologies on par with other supply-side resources and should consider, and quantify where possible, the additional benefits of distributed generation. | PacifiCorp contracted with DNV to provide estimates of expected distributed generation penetration. The study was incorporated in the analysis as a deduction to load. Sensitivities looked at both high and low penetration rates for distributed generation. The study is included in Appendix L (Distributed Generation Study). |

| B.3 - Oregon Standards and Guidelines | | |
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| **13. Resource Acquisition** | | |
| **Reference** | **Requirement** | **2025 IRP Approach** |
| 13.a | An electric utility should, in its IRP:<br>1. Identify its proposed acquisition strategy for each resource in its action plan.<br>2. Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party.<br>Identify any Benchmark Resources it plans to consider in competitive bidding. | Chapter 10 (Action Plan) outlines the procurement approaches for resources identified in the preferred portfolio.<br><br>A discussion of the advantages and disadvantages of owning a resource instead of purchasing it is included in Chapter 10 (Action Plan).<br><br>PacifiCorp has not at this time identified any specific benchmark resources it plans to consider in the competitive bidding process summarized in the 2025 IRP action plan. |
| 13.b | For gas utilities only. | Not Applicable. |

| B.3 - Oregon Standards and Guidelines | | |
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| **Flexible Capacity Resources** | | |
| **Reference** | **Requirement** | **2025 IRP Approach** |
| 1 | Forecast the Demand for Flexible Capacity: The electric utilities shall forecast the balancing reserves needed at different time intervals (e.g. ramping needed within 5 minutes) to respond to variation in load and intermittent renewable generation over the 20- year planning period. | PacifiCorp as met this requirement in Appendix F (Flexible Reserve Study). |
| 2 | Forecast the Supply of Flexible Capacity: The electric utilities shall forecast the balancing reserves available at different time intervals (e.g. ramping available within 5 minutes) from existing generating resources over the 20-year planning period. | PacifiCorp as met this requirement in Appendix F (Flexible Reserve Study). |
| 3 | Evaluate Flexible Resources on a Consistent and Comparable Basis: In planning to fill any gap between the demand and supply of flexible capacity, the electric utilities shall evaluate all resource options, including the use of EVs, on a consistent and comparable basis. | PacifiCorp as met this requirement in Appendix F (Flexible Reserve Study). |

## Table B.4 – Utah Public Service Commission IRP Standards and Guidelines

| B.4 – Utah Standards and Guidelines | | |
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| **Procedural Issues** | | |
| **Reference** | **Requirement** | **2025 IRP Approach** |
| 1 | The Commission has the legal authority to promulgate Standards and Guidelines for integrated resource planning. | Not addressed; this is a Public Service Commission of Utah responsibility. |
| 2 | Information Exchange is the most reasonable method for developing and implementing integrated resource planning in Utah. | Information exchange has been conducted throughout the 2023 IRP process. |
| 3 | Prudence reviews of new resource acquisitions will occur during ratemaking proceedings. | Not an IRP requirement as the Commission acknowledges that prudence reviews will occur during ratemaking proceedings, outside of the IRP process. |
| 4 | PacifiCorp's integrated resource planning process will be open to the public at all stages. The Commission, its staff, the Division, the Committee, appropriate Utah state agencies, and other interested parties can participate. The Commission will pursue a more active-directive role if deemed necessary, after formal review of the planning process. | PacifiCorp's public process is described in Chapter 2 (Introduction). Appendix C (Public Input) provides an overview of the public input process, all public-input meetings held for the 2025 IRP, and summarizes public input received throughout the 2025 IRP cycle. PacifiCorp also made use of a Stakeholder Feedback Form for stakeholders to provide comments and offer suggestions. Stakeholder Feedback Forms along with responses and the public-input meeting presentations are included in Appendix M, and also publicly available on PacifiCorp's webpage at: www.pacificorp.com/energy/integrated-resource-plan.html. |
| 5 | Consideration of environmental externalities and attendant costs must be included in the integrated resource planning analysis. | PacifiCorp used a scenario analysis approach along with cost adders to model environmental externality costs. See Chapter 8 (Modeling and Portfolio Evaluation) for a description of the methodology employed, including how $CO_2$ cost uncertainty is factored into the determination of relative portfolio performance through a base case planning assumption and other price-policy scenarios. |
| 6 | The integrated resource plan must evaluate supply-side and demand-side resources on a consistent and comparable basis. | Supply, transmission, and demand-side resources were evaluated on a comparable basis using PLEXOS optimization models. Also see the response to number 4.b.ii below. |
| 7 | Avoided cost should be determined in a manner consistent with the company's Integrated Resource Plan. | Consistent with Utah rules, PacifiCorp determination of avoided costs in Utah will be handled in a manner consistent with the IRP, with the caveat that the costs may be updated if better information becomes available. |
| 8 | The planning standards and guidelines must meet the needs of the Utah service area, but since coordination with other jurisdictions is important, must not ignore the rules governing the planning process already in place in other jurisdictions. | This IRP was developed in consultation with parties from all state jurisdictions and meets all formal state IRP guidelines. |

| B.4 – Utah Standards and Guidelines | | |
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| **Procedural Issues** | | |
| **Reference** | **Requirement** | **2025 IRP Approach** |
| 9 | The company's Strategic Business Plan must be directly related to its Integrated Resource Plan. | Chapter 10 (Action Plan) describes the linkage between the 2023 IRP preferred portfolio and 2025 business plan resources. The business plan portfolio was run consistent with requirements outlined in the Order issued by the Utah Public Service Commission on September 16, 2016, Docket No. 15-035-04. |

| B.4 – Utah Standards and Guidelines | | |
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| **Standards and Guidelines** | | |
| **Reference** | **Requirement** | **2025 IRP Approach** |
| 1 | Definition: Integrated resource planning is a utility planning process which evaluates all known resources on a consistent and comparable basis, to meet current and future customer electric energy services needs at the lowest total cost to the utility and its customers, and in a manner consistent with the long-run public interest. The process should result in the selection of the optimal set of resources given the expected combination of costs, risk and uncertainty. | Chapter 8 (Modeling and Portfolio Evaluation) outlines the portfolio performance evaluation and preferred portfolio selection process, while Chapter 9 (Modeling and Portfolio Selection Results) chronicles the modeling and preferred portfolio selection process. This IRP also addresses concerns expressed by Utah stakeholders and the Utah commission concerning comprehensiveness of resources considered, consistency in applying input assumptions for portfolio modeling, and explanation of PacifiCorp's decision process for selecting top-performing portfolios and the preferred portfolio. |
| 2 | The company will submit its Integrated Resource Plan biennially. | The company submitted its last IRP on March 31, 2023. PacifiCorp requested and was granted a 60 day extension of time to file the final 2023 IRP on May 31, 2023, in Docket No. 23-035-10. The 2025 IRP filing date is March 31, 2025. |
| 3 | IRP will be developed in consultation with the Commission, its staff, the Division of Public Utilities, the Committee of Consumer Services, appropriate Utah state agencies and interested parties. PacifiCorp will provide ample opportunity for public input and information exchange during the development of its Plan. | PacifiCorp's public process is described in Chapter 2 (Introduction). A record of public meetings and a summary of feedback and public comments is provided in Appendix C (Public Input). |
| 4.a | PacifiCorp's integrated resource plans will include: a range of estimates or forecasts of load growth, including both capacity (kW) and energy (kWh) requirements. | PacifiCorp implemented a load forecast range for both capacity expansion optimization scenarios as well as for stochastic variability, covering both capacity and energy. Details concerning the load forecasts used in the 2025 IRP are provided in Chapter 6 (Load and Resource Balance) and Appendix |

| B.4 – Utah Standards and Guidelines | | |
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| **Standards and Guidelines** | | |
| **Reference** | **Requirement** | **2025 IRP Approach** |
| | | A (Load Forecast). |
| 4.a.i | The forecasts will be made by jurisdiction and by general class and will differentiate energy and capacity requirements. The company will include in its forecasts all on-system loads and those off- system loads which they have a contractual obligation to fulfill. Non-firm off-system sales are uncertain and should not be explicitly incorporated into the load forecast that the utility then plans to meet. However, the Plan must have some analysis of the off-system sales market to assess the impacts such markets will have on risks associated with different acquisition strategies. | Load forecasts are differentiated by jurisdiction and differentiate energy and capacity requirements. See Chapter 6 (Load and Resource Balance) and Appendix A (Load Forecast). Non-firm off-system sales are not incorporated into the load forecast. Off-system sales markets are included in IRP modeling and are used for system balancing purposes. |
| 4.a.ii | Analyses of how various economic and demographic factors, including the prices of electricity and alternative energy sources, will affect the consumption of electric energy services, and how changes in the number, type and efficiency of end-uses will affect future loads. | Appendix A (Load Forecast) documents how demographic and price factors are used in PacifiCorp's load forecasting methodology. |
| 4.b | An evaluation of all present and future resources, including future market opportunities (both demand-side and supply-side), on a consistent and comparable basis. | Resources were evaluated on a consistent and comparable basis using the PLEXOS optimization models for both supply side and demand side alternatives. Resource options are summarized in Chapter 7 (Resource Options). Also refer to portfolio outcomes in Chapter 9 (Modeling and Portfolio Selection Results). |
| 4.b.i | An assessment of all technically feasible and cost-effective improvements in the efficient use of electricity, including load management and conservation. | PacifiCorp included supply curves for Demand Response (dispatchable/schedulable load control) and Energy Efficiency in its capacity expansion model. Details are provided in Chapter 7 (Resource Options). |
| 4.b.ii | An assessment of all technically feasible generating technologies including renewable resources, cogeneration, power purchases from other sources, and the construction of thermal resources. | PacifiCorp considered a wide range of resources including renewables, cogeneration (combined heat and power), power purchases, thermal resources, energy storage, and Energy Gateway transmission configurations. Newly evaluated resources in this IRP include long-term storage options such as 24-hour Hydrogen storage, 100-hour battery and 20 MW biodiesel peaking units. Chapters 7 (Resource Options) and 8 (Modeling and Portfolio Evaluation) describe the assumptions and process under which PacifiCorp developed and assessed these technologies and resources. |
| 4.b.iii | The resource assessments should include: life expectancy of the resources, the recognition of whether the resource is replacing/adding | PacifiCorp captures these resource considerations in its IRP models. Resources are defined as providing capacity, energy, or both. The DSM |

| B.4 – Utah Standards and Guidelines | | |
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| **Standards and Guidelines** | | |
| **Reference** | **Requirement** | **2025 IRP Approach** |
| | capacity or energy, dispatchability, lead-time requirements, flexibility, efficiency of the resource and opportunities for customer participation. | supply curves used for portfolio modeling explicitly incorporate estimated rates of program and event participation. The distributed generation study, modeled as a reduction to load, also considered rates of participation. Replacement capacity is considered in the case of thermal unit retirements as evaluated in this IRP, and as an alternative to coal unit environmental investments. |
| 4.c | An analysis of the role of competitive bidding for demand-side and supply-side resource acquisitions | A description of the role of competitive bidding and procurement is provided in Chapter 10 (Action Plan). |
| 4.d | A 20-year planning horizon. | This IRP uses a 20-year study horizon (2023-2042). In the 2025 IRP, this was expanded to 21 years to capture a requirement particular to this IRP cycle. |
| 4.e | An action plan outlining the specific resource decisions intended to implement the integrated resource plan in a manner consistent with the company's strategic business plan. The action plan will span a four-year horizon and will describe specific actions to be taken in the first two years and outline actions anticipated in the last two years. The action plan will include a status report of the specific actions contained in the previous action plan. | The IRP action plan is provided in Chapter 10 (Action Plan). A status report of the actions outlined in the previous action plan (2023 IRP Update) is provided in Chapter 10 (Action Plan).<br><br>In Chapter 10 (Action Plan) Table 10.1 identifies actions anticipated in the next two-to-four years. |
| 4.f | A plan of different resource acquisition paths for different economic circumstances with a decision mechanism to select among and modify these paths as the future unfolds. | Chapter 10 (Action Plan) includes an acquisition path analysis that presents broad resource strategies based on regulatory trigger events, change in load growth, changes in federal regulation and incentives, and procurement delays. |
| 4.g | An evaluation of the cost-effectiveness of the resource options from the perspectives of the utility and the different classes of ratepayers. In addition, a description of how social concerns might affect cost effectiveness estimates of resource options. | PacifiCorp provides resource-specific utility and total resource cost information in Chapter 7 (Resource Options).<br>The IRP document addresses the impact of social concerns on resource cost-effectiveness in the following ways:<br>● Portfolios were evaluated using a range of $CO_2$ price-policy scenarios.<br>● A discussion of environmental policy status and impacts on utility resource planning is provided in Chapter 3 (Planning Environment).<br>● State and proposed federal public policy preferences for clean energy are considered for development of the preferred portfolio, which is documented in Chapter 9, Appendix O and Appendix P. In addition, distinct state filings also address clean energy.<br>● Appendix G (Plant Water Consumption Study) reports historical water |

| B.4 – Utah Standards and Guidelines | | |
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| **Standards and Guidelines** | | |
| **Reference** | **Requirement** | **2025 IRP Approach** |
| | | consumption for PacifiCorp's thermal plants. |
| 4.h | An evaluation of the financial, competitive, reliability, and operational risks associated with various resource options and how the action plan addresses these risks in the context of both the Business Plan and the 20-year Integrated Resource Plan. The company will identify who should bear such risk, the ratepayer, or the stockholder. | The handling of resource risks is discussed in Chapter 10 (Action Plan), and covers managing environmental risk for existing plants, risk management and hedging and treatment of customer and investment risk. Transmission expansion risks are discussed in Chapter 4 (Transmission).<br><br>Resource capital cost uncertainty and technological risk is addressed in Chapter 7 (Resource Options).<br><br>For reliability risks, stochastic analysis incorporates the historical volatility of forced outages for existing thermal plants and new conversions, as well as historical annual volatility in new and existing wind and solar shapes and existing hydro availability. These risks are factored into the comparative evaluation of portfolios, and the selection of the preferred portfolio upon which the action plan is based.<br><br>Identification of the classes of risk and how these risks are allocated to ratepayers and investors is discussed in Chapter 10 (Action Plan). |
| 4.i | Considerations permitting flexibility in the planning process so that the company can take advantage of opportunities and can prevent the premature foreclosure of options. | Flexibility in the planning and procurement processes is highlighted in Chapter 7 (Resource Options) and Chapter 10 (Action Plan). |
| 4.j | An analysis of tradeoffs; for example, between such conditions of service as reliability and dispatchability and the acquisition of lowest cost resources. | Trade-off analysis including these elements is intrinsic to core model functionality used to determine and evaluate portfolios in the 2025 IRP. Every portfolio incorporates least-cost, least-risk objectives and provides outcomes for documenting comparative assessments, as provided in Chapter 9. Key trade-offs include cost, reliability, emissions, market reliance, integration and reserve requirements, transmission availability, and relevant differences in technology type, location and timing. |

| B.4 – Utah Standards and Guidelines | | |
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| **Standards and Guidelines** | | |
| **Reference** | **Requirement** | **2025 IRP Approach** |
| 4.k | A range, rather than attempts at precise quantification, of estimated external costs which may be intangible, to show how explicit consideration of them might affect selection of resource options. The company will attempt to quantify the magnitude of the externalities, for example, in terms of the number of emissions released and dollar estimates of the costs of such externalities. | PacifiCorp incorporated a range of externality costs for $CO_2$ and costs for complying with current and proposed U.S. EPA regulatory requirements. For $CO_2$ externality costs, the company used scenarios with various compliance requirements to capture a reasonable range of cost impacts. In addition, sensitivities are included to provide estimates of potential impacts that are not or cannot be directly modeled. These modeling assumptions are described in Chapter 8 (Modeling and Portfolio Evaluation). |
| 4.l | A narrative describing how current rate design is consistent with the company's integrated resource planning goals and how changes in rate design might facilitate integrated resource planning objectives. | See Chapter 3 (Planning Environment). The role of Class 3 DSM (price response programs) at PacifiCorp and how these resources are modeled in the IRP are described in Chapter 7 (Resource Options). |
| 5 | PacifiCorp will submit its IRP for public comment, review and acknowledgment. | PacifiCorp distributed draft IRP materials for external review throughout the process prior to each of the public-input meetings and solicited/and received feedback at various times when developing the 2025 IRP. The materials shared with stakeholders at these meetings, outlined in Chapter 2 (Introduction), is consistent with materials presented in Volumes I and II of the 2025 IRP report. Appendix C (Public Input Process) and Appendix M (Stakeholder Feedback Forms) provide expanded details regarding engagement for the 2025 IRP. Public-input meetings materials can be located on PacifiCorp's website at: www.pacificorp.com/energy/integrated-resource-plan/public-input-process.html.<br><br>PacifiCorp requested and responded to comments from stakeholders in throughout its 2025 IRP process. The company also considered comments received via Stakeholder Feedback Forms that can be located on PacifiCorp's website at: www.pacificorp.com/energy/integrated-resource-plan/comments.html A total of 71 Stakeholder Feedback Forms were received and responded to during the 2025 IRP public-input process. |
| 6 | The public, state agencies and other interested parties will have the opportunity to make formal comment to the Commission on the adequacy of the Plan. The Commission will review the Plan for adherence to the principles stated herein and will judge the merit and applicability of the public comment. If the Plan needs further work the | Not addressed; this is a post-filing activity. |

| B.4 – Utah Standards and Guidelines | | |
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| **Standards and Guidelines** | | |
| **Reference** | **Requirement** | **2025 IRP Approach** |
| | Commission will return it to the company with comments and suggestions for change. This process should lead more quickly to the Commission's acknowledgment of an acceptable Integrated Resource Plan. The company will give an oral presentation of its report to the Commission, and all interested public parties.<br>Formal hearings on the acknowledgment of the Integrated Resource Plan might be appropriate but are not required. | |
| 7 | Acknowledgment of an acceptable Plan will not guarantee favorable ratemaking treatment of future resource acquisitions. | Not addressed; this is not a PacifiCorp activity. |
| 8 | The Integrated Resource Plan will be used in rate cases to evaluate the performance of the utility and to review avoided cost calculations. | Not addressed; this refers to a post-filing activity. |

## Washington IRP Requirements

The 2025 IRP aligns with Washington's four-year cadence for filing a full integrated resource plan, inclusive of IRP requirements stemming from CETA rules. Table B.5 reports CETA requirements for RCW 19.280.030 and WAC 480-100-620 through WAC 480-100-630, per Commission General Order R-601.

**Table B.5 – Washington CETA Standards, Rules and Guidelines**

| B.5 – Washington CETA Standards, Rules and Guidelines | | |
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| **Reference** | **Requirement** | **2025 IRP Approach** |
| RCW 19.280.030(3) | Incorporate the social cost of greenhouse gases (SCGHG) as a cost adder, as required by RCW 19.280.030(3):<br>(i) Evaluating and selecting conservation policies, programs, and targets; (ii) Developing integrated resource plans and clean energy action plans; and (iii) Evaluating and selecting intermediate term and long-term resource options.<br>Provide a narrative illustrating step-by-step how the SCGHG cost adder is applied in modeling logic. | PacifiCorp provides a narrative framework outlining carbon price policy scenario assumptions and nominal electric, natural gas price inputs and DSM modeling. Refer to Chapter 8 (Modeling and Portfolio Evaluation). PacifiCorp incorporates the SCGHG into all resource decisions for Washington customers. |
| RCW 19.280.030(1)(m) | Address how the IRP update meets with the requirement in RCW 19.280.030(1)(m) regarding electric and zero-emission vehicles.<br>RCW 19.280.030(1)(m) An analysis of how the plan accounts for:<br>(I) Modeled load forecast scenarios that consider the anticipated levels of zero emissions vehicle use in a utility's service area, including anticipated levels of zero emissions vehicle use in the utility's service area provided in RCW 47.01.520, if feasible;<br>(ii) Analysis, research, findings, recommendations, actions, and any other relevant information found in the electrification of transportation plans submitted under RCW 35.92.450, 54.16.430, and 80.28.365; and<br>(iii) Assumed use case forecasts and the associated energy impacts. Electric utilities may, but are not required to, use the forecasts generated by the mapping and forecasting tool created in RCW 47.01.520. This subsection (1)(m)(iii) applies only to plans due to be filed after September 1, 2023. | PacifiCorp's load forecast accounts for zero-emission vehicles using the methods to determine utility impacts described in the Company's Washington Transportation Electrification Plan. PacifiCorp develops multiple electric vehicle adoption futures for consideration. PacifiCorp updated its zero-emission vehicle forecast in March 2024 account for impacts from the Inflation Reduction Act and recently adopted ZEV standards. |

| B.5 – Washington CETA Standards, Rules and Guidelines | | |
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| **Reference** | **Requirement** | **2025 IRP Approach** |
| WAC 480-100-625(1) and (4) | Integrated resource plan updated every four years, with a progress report at least every two years. | The PacifiCorp IRP is published every two years with updates in the off cycles. This exceeds Washington State requirements. The mid-cycle report is filed as the "Two-year Progress Report" in Washington. |
| WAC 480-100-620(1) | Unless otherwise stated, all assessments, evaluations, and forecasts comprising the plan should extend over the long-range (e.g., at least ten years; longer if appropriate to the life of the resources considered) planning horizon. | PacifiCorp's 2025 (and prior) IRPs span a 20-year long-term planning horizon. Additional analysis may extend or be extrapolated beyond the 20-year horizon under exceptional circumstances based on available data and model performance. |
| WAC 480-100-620(2) | Plan includes range of forecasts of projected customer demand that reflect effects of economic forces on electricity consumption. | The range of load forecast cases includes high load, low load, 1-in-20 load, high distributed generation, low distributed generation, and large metered load growth scenarios. |
| WAC 480-100-620(2) | Plan includes a range of optimistic and pessimistic assumptions of forecast load growth that address changes in the number, type, and efficiency of electrical end-uses, and electrification adjustments made to the forecast. | PacifiCorp conducts a variety of load forecast scenarios. Also, to account for changes in the number, type and efficiency of end-uses, the Company updates its statistically adjusted end-use model used in the load forecast.<br><br>See Appendix A (Load Forecast) for details regarding the alternative load forecast scenarios. Specifically, the Company's base forecast includes expected climate change impacts on loads, while the 20-year normal load forecast scenario provides the load forecast without explicitly accounting for climate change temperatures. Further, the Company does produce both optimistic and pessimistic load forecast scenarios. Please refer to Appendix A (Load Forecast) for details regarding transportation and building electrification adjustments made to the load forecast.<br><br>PacifiCorp has provided detail on load forecasts in Appendix A (Load Forecast). Information can also be found in Chapter 6 (Load and Resource Balance). |
| WAC 480-100-620(3) | Plan includes load management assessments that are cost-effective and commercially available, including current and new policies and programs to obtain: | The IRP is informed by the company's current conservation potential assessment, which is available on PacifiCorp's website. Additional information on the load management assessments can be found in Appendix D (Demand-Side Management Programs). |
| WAC 480-100-620(3) | - all cost-effective conservation, efficiency, and load management improvements; | IRP modeling optimally selects all cost-effective energy efficiency and demand response in each portfolio as a part of core model |

| B.5 – Washington CETA Standards, Rules and Guidelines | | |
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| **Reference** | **Requirement** | **2025 IRP Approach** |
| | - all demand response (DR) at the lowest reasonable cost; | functionality. Results are reported for portfolios in Chapter 9 (Modeling and Portfolio Selection Results) and Appendix O (Clean Energy Action Plan). |
| WAC 480-100-620(3) | - ten-year conservation potential used in the concurrent biennial conservation plan consistent with RCW 19.285.040(1); | The IRP is informed by the current conservation potential assessment, which is available on PacifiCorp's website. Chapter 6 (Load and Resource Balance) provides additional detail. |
| WAC 480-100-620(3) | - identification of opportunities to develop combined heat and power as an energy and capacity resource; and | Combined heat and power are addressed as a component of the Distributed Generation Study, which is included in Appendix L (Distributed Generation Study). |
| WAC 480-100-620(3)(b) | Distributed energy resource (DER) potential assessments (WAC 480-100-620(3)(b))<br><br>Sub-section (iii) (energy assistance potential assessment): The IRP must include distributed energy programs and mechanisms identified pursuant to RCW 19.405.120, which pertains to energy assistance and progress toward meeting energy assistance need.<br><br>Sub-section (iv) (other DER potential assessments) – The IRP must assess other DERs that may be installed by the utility or the utility's customers including, but not limited to, energy storage, electric vehicles, and photovoltaics. Any such assessment must include the effect of DERs on the utility's load and operations. DER potential assessment(s) must go beyond the utility's legacy approach showing DERs as simply a load forecast decrement | The Company assesses various levels of DER through a variety of methods. PacifiCorp evaluates distributed generation by considering varying levels of technology costs and electricity rate assumptions, which are considered within the Company's high and low distributed generation load forecast sensitivities.<br><br>Regarding the energy assistance potential assessment, PacifiCorp evaluates energy efficiency potential by income level so as to inform how energy efficiency resources can meet energy assistance need.<br><br>The 2023 IRP also assesses other DERs such as energy storage, which is considered within the Company's distributed generation study and the CPA as a demand response resource for acquisition is subsequently incorporated into PacifiCorp's load forecast and IRP modeling. Further, utility scale battery storage is considered as a resource option within the context of portfolio analysis. The Company incorporates electric vehicle demand within the load forecast along with the control of electric vehicle load as a demand response resource in the IRP model. |
| WAC 480-100-620(3)(b) | Plan includes assessments of distributed energy programs and mechanisms pertaining to energy assistance and progress toward meeting energy assistance need, incl<br>ding but not limited to the following:<br>- Energy efficiency and CPA, | IRP modeling considers and selects energy efficiency and demand response potential, and distributed energy programs. Evaluation is detailed in Chapter 8 (Modeling and Portfolio), and Chapter 9 (Modeling and Portfolio Selection Results). See Appendix L for the Distributed Generation study and the IRP Studies webpage for the |

| B.5 – Washington CETA Standards, Rules and Guidelines | | |
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| **Reference** | **Requirement** | **2025 IRP Approach** |
| | - Demand response potential,<br>- Energy assistance potential | CPA report, as well. Since at least the 2021 CPA, EE potential has been estimated at the income segmentation level, including for Washington (see CPA Volume 2 Appendix F).<br><br>Since the 2021 IRP, PacifiCorp has contracted with Empower Dataworks to conduct an energy assistance assessment in compliance with WAC 480-100-620(3) guidelines. PacifiCorp shared the findings with Washington stakeholder groups in June 2022, including the Low Income Advisory Group, the DSM Advisory Group, and the EAG. The findings are posted online.[11] PacifiCorp has also discussed this assessment in prior CEIP filings and submits annual reports to the Washington State Department of Commerce. |
| WAC 480-100-620(3)(b) | Plan assesses a forecast of distributed energy resources (DER) that may be installed by the utility's customers via a planning process pursuant to RCW 19.280.100(2). | PacifiCorp has worked with DNV Consulting to prepare a Distributed Generation Study, which assesses private and customer-sited resources. Customer preference resources are also assessed as part of the portfolio selection process. Additional detail can be found in Chapter 8 (Modeling and Portfolio Evaluation). |
| WAC 480-100-620(3)(b) | Plan includes effect of DERs on the utility's load and operations. | The impacts of DERs on PacifiCorp's utility load and operations are assessed as part of Chapter 8 (Modeling and Portfolio Evaluation). Inputs are assessed as part of Appendix L (Distributed Generation Study). |
| WAC 480-100-620(3)(b) | If utility engages in a DER planning process, which is strongly encouraged, IRP should include a summary of the process planning results. | PacifiCorp summarizes relevant activities in Appendix O (Clean Energy Action Plan). Also, summaries of our DER planning processes can be found in the conservation potential assessment and distributed generation studies posted on our website. |
| WAC 480-100-620(4) | Plan assesses wide range of conventional generating resources. | PacifiCorp considered a wide range of resources including renewables, demand-side management, energy storage, distributed energy resources, power purchases, thermal resources, and transmission. Chapter 7 (Resource Options) provides relevant detail on conventional generating resources. |

[11] The 2022 Energy Burden Assessment is available online: https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificorp/energy/ceip/DSM_Advisory%20Group_Meeting_June_Energy_Burden_Assessment_Slides.pdf

| B.5 – Washington CETA Standards, Rules and Guidelines | | |
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| **Reference** | **Requirement** | **2025 IRP Approach** |
| WAC 480-100-620(5) | An assessment of integrating renewable resources addressing overgeneration. | Cost and performance data for all resource types is evaluated and entered as a model input for the optimal selection of resources. The impacts of integration, saturation and curtailments are evaluated in each study as part of model functionality. Additional information can be found in Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection). |
| WAC 480-100-620(5). Also see WA-UTC energy storage policy statement (UE-151069 & UE-161024 consolidated) | Plan assesses energy storage resources. Include an assessment of battery and pumped storage for integrating renewable resources. The assessment may consider ancillary services at the appropriate granularity required to model such storage resources. | Energy storage resources are considered as part of the supply-side resource table, found in Chapter 7 (Resource Options). Energy storage potential is assessed as part of Appendix N (Energy Storage Potential Evaluation). The 2025 IRP incorporates multiple storage options including lithium-ion, flow and iron-air batteries, and pumped hydro storage. Modeling was conducted at appropriate granularity in the PLEXOS LT and ST models. See Chapters 7 and 8. |
| WAC 480-100-620(5) | Plan assesses nonconventional generating, integration, and ancillary service technologies. | Compressed air storage and nuclear resources are represented in the Supply Resource Table, which is posted on PacifiCorp's IRP website and included as Chapter 7 (Resource Options). All resource types are appropriately subject to integration and ancillary services determination, including transmission upgrade costs, reserve holding capability and additional reserve requirements that are particular to technologies. These factors are inherent to every portfolio optimization run. |
| WAC 480-100-620(6) | Plan assesses the availability of regional generation and transmission capacity for purposes of delivery of electricity to customers. | Regional generation is incorporated into market availability and price forecasts, which are described and analyzed in Chapter 3 (Planning Environment), Chapter 5 (Reliability and Resiliency). Transmission and resource options are described in Chapter 4 (transmission) and Chapter 7 (Resource Options). |
| WAC 480-100-620(6) | Plan assesses utility's regional transmission future needs, and the extent transfer capability limitations may affect the future siting of resources. | Regional transmission is represented through markets and region-based price forecasting, while PacifiCorp's transmission system is represented by firm transmission rights and endogenous transmission upgrade options. These factors are discussed in the Chapter 7 (Resource Options) and Chapter 8 (Modeling and Portfolio Evaluation). |

| B.5 – Washington CETA Standards, Rules and Guidelines | | |
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| **Reference** | **Requirement** | **2025 IRP Approach** |
| WAC 480-100-620(7) | Plan compares benefits and risks of purchasing power or building new resources. | As a component of core modeling functionality, all competing resources are evaluated to determine each optimal portfolio. Additional information can be found in Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection Results). |
| WAC 480-100-620(7) | Compare and evaluate all identified resources and potential changes to existing resources for achieving the clean energy transformation standards in WAC 480-100-610 at the lowest reasonable cost, including a narrative of the decisions it has made. Plan compares all identified resources according to resource costs, including: | The 2025 IRP compares all resource options in its optimized evaluation and provides narratives of comparative analysis of outcomes in Chapter 9, and details regarding resource attributes in Chapter 7. The comparison of resources on a cost-risk basis is core functionality of PacifiCorp's optimization modeling. Additional information can be found in Chapter 8 (Modeling and Portfolio Evaluation). |
| WAC 480-100-620(7) | - transmission and distribution delivery costs; | PacifiCorp's transmission system is represented by firm transmission rights and endogenous transmission upgrade options. Transmission dependencies implying additional resource costs are included in the optimization, resulting in a reasonable comparison of resource costs. Additional information can be found in Chapter 7 (Resource Options), Chapter 8 (Modeling and Portfolio Evaluation), and Chapter 9 (Modeling and Portfolio Selection Results). |
| WAC 480-100-620(7) | - risks, including environmental effects and the social cost of GHG emissions; | All variant studies eligible for the preferred portfolio were evaluated under a social cost of greenhouse gases price-policy scenario and evaluated for environmental effects. A range of additional price future impacts and environmental considerations are examined in the 2025 IRP. Refer to Chapter 8 (Modeling and Portfolio Evaluation) and Appendix O (Washington Clean Energy Action Plan). |
| WAC 480-100-620(7) | - benefits accruing to the utility, customers, and program participants (when applicable); and | Benefits are characterized by present value revenue requirement differentials, emissions, reserve and load deficiencies, robustness across stochastic variances and additional factors as may emerge from modeling results. In addition to modeling outcomes presented in Chapter 8 (Modeling and Portfolio Evaluation), incremental costs, community benefits and energy justice are discussed in Appendix O (Clean Energy Action Plan). |
| WAC 480-100-620(7) | - resource preference public policies adopted by WA | The preferred portfolio selected in the 2025 IRP process meets all |

| B.5 – Washington CETA Standards, Rules and Guidelines | | |
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| **Reference** | **Requirement** | **2025 IRP Approach** |
| | State or the federal government. | anticipated policy requirements and considers alternative futures. A summary of the policy and state environment is included as Chapter 3 (Planning Environment), and a description of compliance policy strategy is included as Chapter 8 (Modeling and Portfolio Evaluation), and supplemented by Appendix O (Clean Energy Action Plan). |
| WAC 480-100-620(7) | Plan includes methods, commercially available technologies, or facilities for integrating renewable resources, including but not limited to battery storage and pumped storage, and addressing overgeneration events. | IRP modeling endogenously considers "overgeneration" in dispatch and curtails resources appropriately. These curtailments are an inherent component of the cost and risk valuation of each portfolio, and is a driver for the optimal size, type and location of selected resources. |
| WAC 480-100-620(8) | Plan assesses and determines resource adequacy metrics. | For the 2025 IRP, resource adequacy is evaluated as a core model function, where each portfolio is obligated to meet reliability requirements including varying degrees of quality of operating reserves. In addition, intermodal reliability is considered as long-term and short-term modeling lead to different measures of reliability. See Chapter 8 (Modeling and Portfolio Evaluation). |
| WAC 480-100-620(8) | Identify an appropriate resource adequacy requirement (i.e., loss of load probability) and complete the assessment. | PacifiCorp has addressed this requirement as described in Chapter 6 (Load and Resource Balance) and Appendix K (Capacity Contribution). |
| WAC 480-100-620(8) | Plan measures corresponding resource adequacy metric consistent with prudent utility practice in eliminating coal-fired generation by 12/31/2025 (RCW 19.405.030), attaining GHG neutrality by 1/1/2030 (RCW 19.405.040), and achieving 100 percent clean electricity WA retail sales by 1/1/2045 (RCW 19.405.050). | PacifiCorp has addressed this requirement as pertains to requirements for the Clean Energy Transformation Act and the 2025 IRP as described in Chapter 6 (Load and Resource Balance), Chapter 8 (Modeling and Portfolio Evaluation), and Chapter 9 (Modeling and Portfolio Selection Results), and Appendix O (Clean Energy Action Plan). |
| WAC 480-100-620(9) | Plan reflects the cumulative impact analysis conducted under RCW 19.405.140, and includes an assessment of:<br>- energy and nonenergy benefits;<br>- reduction of burdens to vulnerable populations and highly impacted communities; | Please see Appendix O for details regarding the Company's plan for reporting on metrics related to CBIs. |

| B.5 – Washington CETA Standards, Rules and Guidelines | | |
|---|---|---|
| **Reference** | **Requirement** | **2025 IRP Approach** |
| | - long-term and short-term public health and environmental benefits, costs, and<br>- long-term and short-term public health and environmental risks; and<br>- energy security and risk. | |
| WAC 480-100-620(10) | Utility should include a range of possible future scenarios and input sensitivities for testing the robustness of the utility's resource portfolio under various parameters, including the following required components: | A wide range of cases and sensitivities under various price-policy futures have been included, as discussed in Chapter 8 (Modeling and Portfolio Evaluation). |
| WAC 480-100-620(10) | *CETA counter factual scenario* - describe the alternative least reasonable cost and reasonably available portfolio that the utility would have implemented if not for the requirement to comply with RCW 19.405.040 and RCW 19.405.050, as described in WAC 480-100-660(1). | PacifiCorp has met this requirement – additional detail can be found in Chapter 8 (Modeling and Portfolio Evaluation). |
| WAC 480-100-620(10) | *Climate change scenario* - 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. | PacifiCorp has met this requirement by incorporating climate change in its base assumptions, including future climate impacts on the load forecast, energy efficiency potential, and the hydro generation forecast. The base load forecast for the 2025 IRP is based on a Bureau of Reclamation median projection of climate impacts through time on heating and cooling degree days, resulting in increasing divergence from the 20-year normal weather further in the IRP planning horizon. The hydro forecast similarly relies on projected seasonal changes in streamflows in response to climate impacts that evolve across the IRP planning horizon. Refer to Chapter 8 (Modeling and Portfolio Evaluation) and Appendix A (Load Forecast). |
| WAC 480-100-620(10) | *Maximum customer benefit sensitivity* - model the maximum amount of customer benefits described in RCW 19.405.040(8) prior to balancing against other goals. | PacifiCorp has met this requirement – additional detail on studies can be found in Chapter 8 (Modeling and Portfolio Evaluation) and Appendix O |
| WAC 480-100-620(11) | Integrate the demand forecasts and resource evaluations into a long-range IRP solution describing the mix of resources that meet current and projected resource needs, abiding by a variety of constraints pursuant to statute and per Commission rule | PacifiCorp has met this requirement – additional detail can be found in Chapter 6 (Load and Resource Balance). The PLEXOS models were used to evaluate resources on a comparable basis following the requirements in statute. See Chapter 8 and Appendix O. |

| B.5 – Washington CETA Standards, Rules and Guidelines | | |
|---|---|---|
| **Reference** | **Requirement** | **2025 IRP Approach** |
| WAC 480-100-620(11) | IRP solution or preferred portfolio must describe the resource mix that meets current and projected needs. | PacifiCorp has met this requirement – additional detail can be found in Chapter 9 and Appendix O. |
| WAC 480-100-620(11)(a) | Preferred portfolio must include narrative explanation of the decisions made, including how the utility's long-range IRP solution: | See individual entries below. |
| WAC 480-100-620(11)(a) | - achieves requirements for eliminating coal-fired generation by 12/31/2025 (RCW 19.405.030); | PacifiCorp will remove coal-fired generation from Washington's allocation of electricity by 2025 and will continue to analyze this pending further resolution of interpretive issues by the Commission. Additional information can be found in Chapter 9 (Modeling and Portfolio Selection Results). |
| WAC 480-100-620(11)(a) | - attains GHG neutrality by 1/1/2030 (RCW 19.405.040); and | PacifiCorp has met this requirement. Additional information can be found in Chapter 8 (Modeling and Portfolio Evaluation), and Chapter 9 (Modeling and Portfolio Selection Results), and Appendix O (Clean Energy Action Plan). |
| WAC 480-100-620(11)(a) | - achieves 100 percent clean electricity WA retail sales by 1/1/2045 (RCW 19.405.050) at lowest reasonable cost, | This requirement is met as described in Chapter 8 (Modeling and Portfolio Evaluation), and Chapter 9 (Modeling and Portfolio Selection Results), and Appendix O (Clean Energy Action Plan). |
| WAC 480-100-620(11)(a) | - achieves 100 percent clean electricity WA retail sales by 1/1/2045 (RCW 19.405.050), considering risk. | This requirement is met as described in Chapter 8 (Modeling and Portfolio Evaluation), and Chapter 9 (Modeling and Portfolio Selection Results), and Appendix O (Clean Energy Action Plan). |
| WAC 480-100-620(11)(c) | Consistent with RCW 19.285.040(1), preferred portfolio shows pursuit of all cost-effective, reliable, and feasible conservation and efficiency resources, and DR. | PacifiCorp has met this requirement. Additional information can be found in Chapter 8 (Modeling and Portfolio Evaluation), and Chapter 9 (Modeling and Portfolio Selection Results), and Appendix O (Clean Energy Action Plan). |
| WAC 480-100-620(11)(d) and I | Preferred portfolio considers acquisition of existing renewable new resources and relies on renewable resources and energy storage, insofar as doing so is at lowest reasonable cost. | PacifiCorp has met this requirement. Additional information can be found in Chapter 8 (Modeling and Portfolio Evaluation), and Chapter 9 (Modeling and Portfolio Selection Results), and Appendix O (Clean Energy Action Plan). |
| WAC 480-100-620(11)(d) and (e) | Preferred portfolio considers acquisition of existing renewable new resources and relies on renewable resources and energy storage, considering risks. | PacifiCorp has met this requirement. Additional information can be found in Chapter 8 (Modeling and Portfolio Evaluation), and Chapter 9 (Modeling and Portfolio Selection Results), and Appendix O |

| B.5 – Washington CETA Standards, Rules and Guidelines | | |
|---|---|---|
| **Reference** | **Requirement** | **2025 IRP Approach** |
| | | (Washington Clean Energy Action Plan). |
| WAC 480-100-620(11)(f) | Preferred portfolio maintains and protects the safety, reliable operation, and balancing of the utility's electric system, including mitigating over-generation events and achieving identified resource adequacy requirements. | PacifiCorp has met this requirement. In addition to inherent modeling functionality, additional information can be found in Chapter 6 (Load and Resource Balance). |
| WAC 480-100-620(11)(g) | Preferred portfolio ensures all customers are benefiting from the transition to clean energy through the: | See individual entries below. |
| WAC 480-100-620(11)(g) | - equitable distribution of energy and nonenergy benefits; reduction of burdens to vulnerable populations and highly impacted communities; demonstrate a wider incorporation of non-energy impacts (NEIs) in addition to those applied during conservation potential assessment (CPA) development. | Please see Appendix O (Clean Energy Action Plan). |
| WAC 480-100-620(11)(g) | - long-term and short-term public health and environmental benefits; reduction of costs and risks; and | Please see Appendix O (Clean Energy Action Plan). |
| WAC 480-100-620(11)(g) | - energy security and resiliency. | Please see Appendix O (Clean Energy Action Plan). |
| WAC 480-100-620(11)(h) | - Please see Appendix O (Clean Energy Action Plan). | Please see Appendix O (Clean Energy Action Plan). |
| WAC 480-100-620(11)(i) | - analyzes and considers combinations of DER costs, benefits, and operational characteristics (incl. ancillary services) to meet system needs, | Detail is included in Chapter 8 (Modeling and Portfolio Evaluation), Appendix L (Distributed Generation Study) and discussion in Appendix O (Washington Clean Energy Action Plan). |
| WAC 480-100-620(11)(j) | - incorporates the social cost of GHG emissions as a cost adder. | Detail is included in Chapter 8 (Modeling and Portfolio Evaluation) and Appendix O (Washington Clean Energy Action Plan). |
| WAC 480-100-620(12) | Utility must develop a ten-year clean energy action plan (CEAP) for implementing RCW 19.405.030 through 19.405.050 at lowest reasonable cost, and at an acceptable resource adequacy standard. | The Company's 2025 CEAP is provided as Appendix O (Washington Clean Energy Action Plam). See individual entries below. |

| B.5 – Washington CETA Standards, Rules and Guidelines | | |
|---|---|---|
| **Reference** | **Requirement** | **2025 IRP Approach** |
| | The CEAP will: | |
| WAC 480-100-620(12)(b) | - identify and be informed by utility's ten-year CPA per RCW 19.285.040(1); | Please see Appendix O (Washington Clean Energy Action Plan). |
| WAC 480-100-620(12)(c) | - demonstrate that all customers are benefiting from the transition to clean energy; | Please see Appendix O (Washington Clean Energy Action Plan). |
| WAC 480-100-620(12)(d) | - establish a resource adequacy requirement; | PacifiCorp establishes resource adequacy at a system level, and the resource adequacy requirement is explained in Chapter 6 (Load and Resource Balance). |
| WAC 480-100-620(12)(e) | - identify the potential cost-effective DR and load management programs that may be acquired; | This requirement is met in Chapter 9 (Modeling and Portfolio Selection Results) and Appendix O (Washington Clean Energy Action Plan). |
| WAC 480-100-620(12)(f) | - identify renewable resources, non emitting electric generation, and DERs that may be acquired and evaluate how each identified resource may be expected to contribute to meeting the utility's resource adequacy requirement; | This is described as part of PacifiCorp's resource planning process. Chapter 7 (Resource Options), Chapter 8 (Modeling and Portfolio Evaluation), and Chapter 9 (Modeling and Portfolio Selection) provide additional detail. Also see Appendix L and Appendix O with reference to DERs. |
| WAC 480-100-620(12)(g) | - identify any need to develop new, or expand or upgrade existing, bulk transmission and distribution facilities; | This is described at the system level in Chapter 4 (Transmission) and within PacifiCorp's Chapter 10 (Action Plan). |
| WAC 480-100-620(12)(h) | - identify the nature and possible extent to which the utility may need to rely on alternative compliance options, if appropriate. | Please see Appendix O (Washington Clean Energy Action Plan). |
| WAC 480-100-620(12)(i) | Plan (both IRP and CEAP) considers cost of greenhouse gas emissions as a cost adder equal to the cost per metric ton of carbon dioxide emissions, using the two and one-half percent discount rate, listed in Table 2, Technical Support Document: Technical update of the social cost of carbon (SCC) for regulatory impact analysis under Executive Order 12866, published by the interagency working group on social cost of greenhouse gases of the United States government, August 2016, as adjusted by the Commission to reflect the effect of inflation. | PacifiCorp updated its social cost of greenhouse gas pricing consistent with DOCKET U-190730 ORDER 03, which updates this specification. |

| B.5 – Washington CETA Standards, Rules and Guidelines | | |
|---|---|---|
| **Reference** | **Requirement** | **2025 IRP Approach** |
| WAC 480-100-620(13) | Plan must include an analysis and summary of the estimated avoided cost for each supply- and demand-side resource, including (but not limited to):<br>- energy,<br>- capacity,<br>- transmission,<br>- distribution, and<br>- GHG emissions. | A new assessment of avoided cost is not a requirement of the Two-Year Progress Report; however, future determinations of avoided cost will follow the guidelines below.<br><br>The estimated avoided cost will be based on the values determined through the IRP modeling process. Values can be found in Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection). |
| WAC 480-100-620(13) | Listed energy and non-energy impacts should specify to which source party they accrue (e.g., utility, customers, participants, vulnerable populations, highly impacted communities, general public). | The file labeled "2025 CPA - Appendix E - WA Non-Energy Impact Mapping", as part of the CPA supplemental materials posted on the website, maps the accrual of NEIs to various groups consistent with WAC 480-100-620(13). |
| WAC 480-100-620(14) | To maximize transparency, the utility should submit data input files supporting the plan in native file format (e.g., supporting spreadsheets in Excel, not PDF file format). | PacifiCorp will make data available in the native file format consistent with practice in prior IRPs. |
| WAC 480-100-620(15) | Information relating to purchases of electricity from qualifying facilities. Each utility must provide information and analysis that it will use to inform its annual filings required under chapter 480-106 WAC. The detailed analysis must include, but is not limited to, the following components: | See individual entries, below. |
| WAC 480-100-20(15)(a) | - A description of the methodology used to calculate estimates of the avoided cost of energy, capacity, transmission, distribution and emissions averaged across the utility; and | The estimated avoided cost will be based on the values determined through the IRP modeling process. Values can be found in Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection). |
| WAC 480-100-20(15)(b) | - Resource assumptions and market forecasts used in the utility's schedule of estimated avoided cost required in WAC 480-106-040 including, but not limited to, cost assumptions, production estimates, peak capacity contribution estimates and annual capacity factor estimates. | The estimated avoided cost will be based on the values determined through the IRP modeling process. Values can be found in Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection). |
| WAC 480-100-620(16) | Plan must summarize substantive changes to modeling | A comprehensive discussion of modeling methodology updates is |

| B.5 – Washington CETA Standards, Rules and Guidelines | | |
|---|---|---|
| **Reference** | **Requirement** | **2025 IRP Approach** |
| | methodologies or inputs that change the utility's resource need, as compared to the utility's previous IRP. | included in Chapter 8 (Modeling and Portfolio Evaluation), however a brief list of highly impactful changes and updates is as follows:<br>• Model must meet WRAP compliance.<br>• Existing thermal units can operate indefinitely with maintenance.<br>• IRA Tax Credits are extended through the whole horizon.<br>• States are only able to impact the disposition of resources in which they have an active share. |
| WAC 480-100-620(17) | Utility must summarize:<br>- public comments received on the draft IRP,<br>- utility's responses to public comments, and<br>- whether final plan addresses and incorporates comments raised. | PacifiCorp has maintained compliance with this requirement by publishing all stakeholder comments received and associated responses in a centralized location externally and additionally provides this feedback with PacifiCorp responses in Appendix M, including a summary matrix of pertinent information. |
| WAC 480-100-625(4) | Two-year progress report. At least every two years after the utility files its IRP, beginning January 1, 2023, the utility must file a two-year progress report.<br>(a) In this report, the utility must update its:<br>(i) Load forecast;<br>(ii) Demand-side resource assessment, including a new conservation potential assessment;<br>(iii) Resource costs; and<br>(iv) The portfolio analysis and preferred portfolio.<br>(b) The progress report must include other updates that are necessary due to changing state or federal requirements, or significant changes to economic or market forces.<br>(c) The progress report must also update for any elements found in the utility's current clean energy implementation plan, as described in WAC 480-100-640. | Not applicable. The 2025 IRP aligns with Washington's four-year IRP filing cadence. The next two-year progress report is anticipated to be filed in 2027. |
| WAC 480-100-630(1) | The utility must demonstrate and document how it considered input from advisory group members in the development of its IRP and two-year progress report. | PacifiCorp meets this requirement in the 2025 IRP in Appendix C and Appendix M and also references stakeholder feedback in footnotes throughout the 2025 IRP document. |

| B.5 – Washington CETA Standards, Rules and Guidelines | | |
|---|---|---|
| **Reference** | **Requirement** | **2025 IRP Approach** |
| WAC 480-100-630(2) | The utility must make available completed presentation materials for each advisory group meeting at least three business days prior to the meeting. The utility may update materials as needed. | PacifiCorp has met this requirement throughout the 2025 IRP public input meeting series, and as documented in Appendix C and Appendix M. |
| WAC 480-100-630(3) | The utility must make all its data inputs and files used to develop its IRP available to the commission in native file format, per RCW 19.280.030 (10)(a) and (b), and in an easily accessible format. | PacifiCorp carefully manages its workpaper filing to adhere to this requirement within the limits of technology. Context is provided by the accompanying listing of file names with a description of the file's content or purpose. This information is provided with the supporting workpapers. |
| WAC 480-106-040 | Plan provides information and analysis used to inform annual purchases of electricity from qualifying facilities, including a description of the: | See individual entries below: |
| WAC 480-106-040 | - avoided cost calculation methodology used; | The estimated avoided cost will be based on the values determined through the IRP modeling process. Values can be found in Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection). |
| WAC 480-106-040 | - avoided cost methodology of energy, capacity, transmission, distribution, and emissions averaged across the utility; and | The estimated avoided cost will be based on the values determined through the IRP modeling process. Values can be found in Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection). |
| WAC 480-106-040 | - resource assumptions and market forecasts used in the utility's schedule of estimated avoided cost, including (but not limited to): cost assumptions, production estimates, peak capacity contribution<br>estimates, and annual capacity factor estimates. | The estimated avoided cost will be based on the values determined through the IRP modeling process. Values can be found in Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection). However, resource assumptions, capacity factors and price forecasts are included in workpapers. PacifiCorp would note that its 2025 IRP uses forward market prices from September 2024, which is the same vintage as PacifiCorp's October 30, 2024 avoided cost filing in docket number 240817. |

**Table B.6 – Wyoming Public Service Commission Guidelines**

| Reference | Requirement | 2025 IRP Approach |
|---|---|---|
| A | The public comment process employed as part of the formulation of the utility's IRP, including a description, timing and weight given to the public process; | PacifiCorp's public process is described in Chapter 2 (Introduction) and in Appendix C (Public Input). |
| B | The utility's strategic goals and resource planning goals and preferred resource portfolio; | Chapter 9 (Modeling and Portfolio Selection Results) documents the preferred resource portfolio and rationale for selection. Chapter 10 (Action Plan) constitutes the IRP action plan and the descriptions of resource strategies and risk management. |
| C | The utility's illustration of resource need over the near-term and long-term planning horizons; | See Chapter 6 (Load and Resource Balance). |
| D | A study detailing the types of resources considered; | Volume, I Chapter 7 (Resource Options), presents the resource options used for resource portfolio modeling for this IRP. |
| E | Changes in expected resource acquisitions and load growth from that presented in the utility's previous IRP; | A comparison of resource changes relative to the 2023 IRP is presented in Chapter 10 (Action Plan). A chart comparing the peak load forecasts for the 2025 IRP and 2023 IRP is included in Appendix A (Load Forecast Details). |
| F | The environmental impacts considered; | Portfolio comparisons for CO2 and a broad range of environmental impacts are considered, including prospective early retirement and gas conversions of existing coal units as alternatives to environmental investments. See Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection). |
| G | Market purchases evaluation; | Modeling of firm market purchases (front office transactions) and spot market balancing transactions is included in the 2025 IRP. |
| H | Reserve Margin analysis; and | Reserve margin analysis is included in Chapter 8 (Modeling and Portfolio Evaluation). |
| I | Demand-side management and conservation options; | See Chapter 7 (Resource Options) and Appendix D (Demand-side Management) for a detailed discussion on DSM and energy efficiency resource options. Additional information on energy efficiency resource characteristics is available on the company's website. |

# APPENDIX C – PUBLIC INPUT PROCESS

A critical element of this Integrated Resource Plan (IRP) is the public input process. PacifiCorp has pursued an open and collaborative approach involving the commissions, customers, and other stakeholders in PacifiCorp's IRP prior to making resource planning decisions. Since these decisions can have significant economic and environmental consequences, conducting the IRP with transparency and full participation from interested and affected parties is essential to achieve long-term planning objectives.

Stakeholders have been involved in the development of the 2025 IRP from the beginning. The public input meetings held beginning in January 2024 were the cornerstone of the direct public-input process, and 10 public input meetings are included as part of the 2025 IRP development cycle. In addition to the 2025 IRP public input meeting series, the IRP continues to be represented as appropriate in advisory group meetings and in communications with regulators in all jurisdictions.

PacifiCorp's integrated resource plan website houses feedback forms included in this filing. This standardized form allows stakeholders to provide comments, questions, and suggestions. PacifiCorp also posts its responses to the feedback forms at the same location. Feedback forms and PacifiCorp's responses can be found via the following link:

https://www.pacificorp.com/energy/integrated-resource-plan/comments.html

## Participant List

PacifiCorp's 2025 IRP continues to be a robust process involving input from many parties. Participants included commissions, stakeholders, and industry experts. Among the organizations that have been represented and actively involved in this collaborative effort are:

### Commissions

- California Public Utilities Commission
- Idaho Public Utilities Commission
- Oregon Public Utility Commission
- Public Service Commission of Utah
- Washington Utilities and Transportation Commission
- Wyoming Public Service Commission

***PacifiCorp extends its gratitude for participants' continued time and energy devoted to the IRP process. Their participation has contributed significantly to the quality of this plan.***

## Stakeholders and Industry Experts

AES Corporation
Ameresco
Anchor Blue
Apex Clean Energy
Applied Energy Group
Birch Creek
Cascade Natural Gas
City of Kemmerer Wyoming
City of SLC
Cottonwood Heights, UT
DNV
Energy Strategies
Energy Trust of Oregon
ENYO Energy
ESS, INC
Fervo Energy
First Principles
Green Energy International
Grid United
Holland & Hart
Idaho Power
Idaho Public Utilities Commission
Intermountain Wind-Colorado
Interwest Energy Alliance
James Dodge Russell & Stephens, P.C.
Key Capture Energy
Mitsubishi Heavy Industries
Northwest Energy Coalition
Northwest Power Council
NP Energy
NWEC
Oregon Citizen Utility Board
Oregon League of Women Voters
Oregon Public Utility Commission
Orsted
Portland General Electric
Powder River Basin Conservation League
Powder River Basin Resource Council
Renewable Energy Coalition
Renewable Northwest
RMI
rPlus Energies
Salt Lake City
Sierra Club
SLC Corp
Southwest Energy Efficiency Project
State of Wyoming
University of Wyoming
Utah Citizens Advocating Renewable Energy (UCARE)
Utah Clean Energy
Utah Department of Agriculture and Food
Utah Department of Environmental Quality
Utah Division of Public Utilities
Utah Needs Clean Energy
Utah OCS (Utah Office of Consumer Services)
Utah Public Service Commission
Utah Valley University
Vote Solar
Washington Public Service Commission
Washington Utilities and Transportation Commission
Western Electricity Coordinating Council
Western Energy Storage Task Force
Western Resource Advocates
Wyoming Business Council
Wyoming Coalition of Local Governments
Wyoming Energy Consumers
Wyoming Office of Consumer Advocates
Wyoming Public Service Commission

# General Meetings and Agendas

During the 2025 IRP public input process presentations and discussions have covered various issues regarding inputs, assumptions, risks, modeling techniques, planned studies and analytical results.[1] Below are the agendas from the public input meetings; the presentations and recordings of the meetings are available at:

https://www.pacificorp.com/energy/integrated-resource-plan/public-input-process.html

## General Meetings

**January 25, 2024**

- 2025 IRP Public Meeting Kick-off
- 2023 IRP Filing Update
- 2025 IRP Overview
- 2023 IRP Status and Update
- 2025 IRP
    - Conservation Potential Assessment Planning
    - Supply-Side Resource development

**March 14, 2024**

- Planning Environment Updates
- Input Data Development
- Optimization Modeling Overview
- PLEXOS Modeling
- 2023 IRP Update Drafting

**May 2, 2024**

- Conservation Potential Update
- Distributed Generation Study Overview
- Transmission Modeling Strategy
- March price curve update
- 2023 IRP Update Outcomes

**June 26-27, 2024**

- Federal Policy Updates
- Draft Load Forecast Update
- Hydro Forecast Under Climate Change
- Distributed Generation Update
- Reliability and Resource Adequacy
- Supply Side Resources – Alternative Fuels
- Qualifying Facility Renewals
- Transmission Interconnection Options

[1] The 2025 IRP public process included discussions of inputs and planned studies throughout, as noted in Appendix M, stakeholder feedback form #3 (Oregon Public Utilities Commission)

**July 17-18, 2024**
- 2023 IRP Filing Update
- Distribution System Planning Update
- Renewable Portfolio Standards
- Price-Policy Scenarios
- Market Reliance
- Volatility and Stochastics
- Preview 2025 IRP Studies
- Supply Side Resources Update – Assumptions and Attributes
- Emissions Modeling
- DSM Bundling Portfolio Methodology

**August 14-15, 2024**
- Generation Transition, Equity and Justice
- Regional Haze Update
- Emissions Reporting Update
- State Updates
- 2025 IRP Studies Update
- Existing Thermal Resource Options
- Daily Shapes
- 2023 IRP Update Progress
- Transmission Option Dependencies
- Customer Preference
- Supply Side Resource Table

**September 25, 2024**
- 2025 IRP Progress Report
- Supply-side Resources
- Data Center Load Studies
- State and Federal Updates

**January 22-23, 2025**
- 2025 IRP Progress Report
- Integration and Allocation
- Additional Model Results
- Stochastics
- Long-term Duration Storage
- CPA
- Market Purchase Limits
- Local Load Study

**February 27, 2025**
- Modeling Refinements
- DSM
- Stochastics

In addition to the topics listed above, each public input meeting incorporated a concluding discussion of stakeholder feedback forms received and next steps.

## Stakeholder Comments

In the 2025 IRP cycle, in recognition of the importance of stakeholder feedback, PacifiCorp provided a form which gave participants a direct opportunity to provide comments, questions, and suggestions in addition to the opportunities for discussion at public input meetings. Please refer to Appendix M (Stakeholder Feedback) to view submitted Stakeholder Feedback Forms, including responses, for the 2025 IRP. These completed forms, and also a blank for new submissions, are also located on the PacifiCorp website at the IRP comments webpage:

www.pacificorp.com/energy/integrated-resource-plan/comments.html.

## Contact Information

PacifiCorp's IRP website: www.pacificorp.com/energy/integrated-resource-plan.html.

Stakeholders and members of the public can also send comments, questions and requests to the following email address:

IRP@PacifiCorp.com

# APPENDIX D – DEMAND-SIDE MANAGEMENT

## Introduction

This appendix reviews the studies and reports used to support the demand-side management (DSM) resource information used in the modeling and analysis of the 2025 Integrated Resource Plan (IRP). In addition, it provides information on the economic DSM selections in the 2025 IRP's Preferred Portfolio, a summary of existing DSM program services and offerings, and an overview of the DSM planning process in each of PacifiCorp's service areas.

## Conservation Potential Assessment (CPA) for 2025-2044

Since 1989, PacifiCorp has developed biennial IRPs to identify an optimal mix of resources that balance considerations of cost, risk, uncertainty, supply reliability/deliverability, and long-run public policy goals. The optimization process accounts for capital, energy, and ongoing operation costs as well as the risk profiles of various resource alternatives, including traditional generation and market purchases, renewable generation, and DSM resources such as energy efficiency, and demand response or capacity-focused resources. Since the 2008 IRP, DSM resources have competed directly against supply-side options, allowing the IRP model to guide decisions regarding resource mixes, based on cost and risk.

The Conservation Potential Assessment (CPA) for 2025-2044,[1] conducted by Applied Energy Group (AEG) on behalf of PacifiCorp, primarily seeks to develop reliable estimates of the magnitude, timing, and costs of DSM resources likely available to PacifiCorp over the IRP's 20-year planning horizon. The study focuses on resources realistically achievable during the planning horizon, given normal market dynamics that may hinder or advance resource acquisition. Study results were incorporated into PacifiCorp's 2025 IRP and will be used to inform subsequent DSM planning and program design efforts. This study serves as an update of similar studies completed since 2007.

For resource planning purposes, PacifiCorp classifies DSM resources into four categories or "classes," differentiated by two primary characteristics: reliability and customer choice. These resource classifications can be defined as: Class 1 is demand response (e.g., a firm, capacity focused resource such as direct load control), Class 2 is energy efficiency (e.g., a firm energy intensity resource such as conservation), Class 3 is demand side rates (DSR) (e.g., a non-firm, capacity focused resource such as time of use rates), and Class 4 is non-incented behavioral-based response (e.g., customer energy management actions through education and information).

From a system-planning perspective, demand response resources can be considered the most reliable, as they can be dispatched by the utility. In contrast, behavioral-based resources are the least reliable due to the resource's dependence on voluntary behavioral changes. With respect to customer choice, demand response and energy efficiency resources should be considered involuntary in that, once equipment and systems have been put in place, savings can be expected to occur over a certain period. DSR and non-incented behavioral-based activities involve greater

[1] PacifiCorp's Demand-Side Resource Potential Assessment for 2025-2044, completed by AEG, can be found at: www.pacificorp.com/energy/integrated-resource-plan/support.html.

customer choice and control. This assessment estimates potential from demand response, energy efficiency, and DSR.

The CPA excludes an assessment of Oregon's energy efficiency resource potential, as this work is performed by Energy Trust of Oregon, which provides energy efficiency potential in Oregon to PacifiCorp for resource planning purposes.

## Current DSM Program Offerings by State

Currently, PacifiCorp offers a robust portfolio of DSM 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 has the most up-to-date programs on its website.[2] Demand response and energy efficiency program services and offerings are available by state and sector. Energy efficiency services listed for Oregon, except for low-income weatherization services, are provided in collaboration with Energy Trust of Oregon.[3]

Table D.1 provides an overview of the breadth of demand response and energy efficiency program services and offerings available by Sector and State.

PacifiCorp has numerous DSR offerings currently available. They include metered time-of-day and time-of-use pricing plans (in all states, availability varies by customer class), and residential seasonal rates (Idaho and Utah). System-wide, approximately 14,467 customers were participating in metered time-of-day and time-of-use programs as of 2023.

Savings associated with rate design are captured within the company's load forecast and are thus captured in the integrated resource planning framework. PacifiCorp continues to evaluate DSR programs for applicability to long-term resource planning.

PacifiCorp provides behavioral based offerings as well. Educating customers regarding energy efficiency and load management opportunities is an important component of PacifiCorp's long-term resource acquisition plan. A variety of channels are used to educate customers including television, radio, newspapers, bill inserts and messages, newsletters, school education programs, and personal contact. Load reductions due to behavioral activity will show up in demand response and energy efficiency program results and non-program reductions in the load forecast over time.

**Table D.1– Current Demand Response and Energy Efficiency Program Services and Offerings by Sector and State**

| Program Services & Offerings by Sector and State | California | Oregon | Washington | Idaho | Utah | Wyoming |
|---|---|---|---|---|---|---|
| ***Residential Sector*** | | | | | | |
| Air Conditioner Direct Load Control | | √ | √ | | √ | |
| Lighting Incentives | √ | √ | √ | √ | √ | √ |
| New Appliance Incentives | √ | √ | √ | √ | √ | √ |

[2] Programs for Rocky Mountain Power can be found at www.rockymountainpower.net/savings-energy-choices.html and programs for Pacific Power can be found at www.pacificpower.net/savings-energy-choices.html.
[3] Funds for low-income weatherization services are forwarded to Oregon Housing and Community Services.

| Program Services & Offerings by Sector and State | California | Oregon | Washington | Idaho | Utah | Wyoming |
|---|---|---|---|---|---|---|
| Heating And Cooling Incentives | √ | √ | √ | √ | √ | √ |
| Weatherization Incentives - Windows, Insulation, Duct Sealing, etc. | √ | √ | √ | √ | √ | √ |
| New Homes | √ | √ | √ | √ | √ | √ |
| Low-Income Weatherization | √ | √ | √ | √ | √ | √ |
| Home Energy Reports | | √ | √ | √ | √ | √ |
| School Curriculum | | √ | √ | | √ | |
| Financing Options with On-Bill Payments | | √ | √ | | | |
| Trade Ally Outreach | √ | √ | √ | √ | √ | √ |
| Electric Vehicle Load Control | | √ | √ | | √ | |
| Battery Load Control | | √ | √ | | √ | |

| Program Services & Offerings by Sector and State | California | Oregon | Washington | Idaho | Utah | Wyoming |
|---|---|---|---|---|---|---|
| ***Non-Residential Sector*** | | | | | | |
| Irrigation Load Control | | √ | √ | √ | √ | |
| Commercial and Industrial Demand Response | | √ | √ | √ | √ | |
| Standard Incentives | √ | √ | √ | √ | √ | √ |
| Energy Engineering Services | √ | √ | √ | √ | √ | √ |
| Billing Credit Incentive (offset to DSM charge) | | √ | | | √ | √ |
| Energy Management | √ | √ | √ | √ | √ | √ |
| Energy Profiler Online | √ | √ | √ | √ | √ | √ |
| Business Solutions Toolkit | √ | √ | √ | √ | √ | √ |
| Trade Ally Outreach | √ | √ | √ | √ | √ | √ |
| Small Business Lighting | | √ | √ | √ | √ | √ |
| Lighting Instant Incentives | √ | √ | √ | √ | √ | √ |
| Small to Mid-Sized Business Facilitation | √ | √ | √ | √ | √ | √ |
| DSM Project Managers Partner with Customer Account Managers | √ | √ | √ | √ | √ | √ |

Table D.2 provides an overview of DSM related *Watt*smart Outreach and Communication activities (Class 4 DSM activities) by state.

**Table D.2 – Current W*att*smart Outreach and Communications Activities**

| *Watt*smart Outreach & Communications (incremental to program specific advertising) | California | Oregon | Washington | Idaho | Utah | Wyoming |
|---|---|---|---|---|---|---|
| Advertising | | √ | √ | √ | √ | √ |
| Sponsorships | | √ | √ | √ | √ | √ |
| Social Media | √ | √ | √ | √ | √ | √ |
| Public Relations | √ | √ | √ | √ | √ | √ |
| Business Advocacy (awards at customer meetings, sponsorships, chamber partnership, university partnership) | √ | √ | √ | √ | √ | √ |
| *Watt**smart*** Workshops and Community Outreach | √ | √ | √ | √ | √ | √ |
| BE W*att**smart***, Begin at Home - in school energy education | | | √ | √ | √ | √ |

## State-Specific DSM Planning Processes

A summary of the DSM planning process in each state is provided below.

### Utah, Wyoming, and Idaho

The company's biennial IRP and associated action plan provides the foundation for DSM acquisition targets in each state. Where appropriate, the company maintains and uses external stakeholder groups and vendors to advise on a range of issues including annual goals for conservation programs, development of conservation potential assessments, development of multi-year DSM plans, program marketing, incentive levels, budgets, adaptive management, and the development of new and pilot programs.

### Washington

The company is one of three investor-owned utilities required to comply with Washington's Energy Independence Act (also referred to as I-937) approved in November 2006. The Act requires utilities to pursue all conservation that is cost-effective, reliable, and feasible. Every two years, each utility must identify its 10-year conservation potential and two-year acquisition target based on its IRP and using methodologies that are consistent with those used by the Northwest Power and Conservation Council. Each utility must maintain and use an external conservation stakeholder group that advises on a wide range of issues including conservation programs, development of conservation potential assessments, program marketing, incentive levels, budgets, adaptive management, and the development of new and pilot programs. PacifiCorp works with the conservation stakeholder group annually on its energy efficiency program design and planning.

In 2019, Washington passed the Clean Energy Transformation Act (CETA), which requires utilities to meet three primary clean energy standards: remove coal-fueled generation from Washington's allocation of electricity by 2025, serve Washington customers with greenhouse gas neutral electricity by 2030, and to serve customers in Washington with 100% renewable and non-emitting electricity by 2045. The conservation stakeholder group and the demand-side management advisory group inform the CETA planning process as documented in the Company's Clean Energy Implementation Plan (CEIP).[4]

## California

On October 9, 2024, PacifiCorp submitted to the Commission the Company's Biennial Budget Advice Letter (BBAL) Filing 747-E to administering its energy efficiency programs through 2026. The BBAL was submitted PacifiCorp submitted in accordance with Ordering Paragraph 4 of Decision (D.) 21-12-034 an application for the continuation of energy efficiency programs for program years 2022-2026 on December 31, 2020.

## Oregon

Energy efficiency programs for Oregon customers are planned for and delivered by Energy Trust of Oregon in collaboration with PacifiCorp. Energy Trust's planning process is comparable to PacifiCorp's other states, including establishing resource acquisition targets based on resource assessment and integrated resource planning, developing programs based on local market conditions, and coordinating with stakeholders and regulators to ensure efficient and cost-effective delivery of energy efficiency resources.

# Preferred Portfolio DSM Resource Selections

The following tables show the economic DSM resource selections for both demand response and energy efficiency by state and year in the 2025 IRP preferred portfolio.[5]

Table D.3 shows cumulative additional demand response selections in units of MW capacity during summer and winter seasons by state and year. This does not include already existing demand response resources but is rather additional to them.

[4] The Company's 2021 CEIP can be found online at https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/ceip/PAC-CEIP-12-30-21_with_Appx.pdf

[5] These DSM resource selections follow the methodologies described in Chapter 7.

**Table D.3 –Cumulative Demand Response Resource Selections (2025 IRP Preferred Portfolio) (MW)**

| Resource | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| DR Summer - CA | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| DR Winter - CA | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| DR Summer - ID | 0 | 0 | 0 | 0 | 0 | 4 | 9 | 9 | 9 | 9 | 9 |
| DR Winter - ID | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| DR Summer - OR | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| DR Winter - OR | 0 | 0 | 0 | 48 | 64 | 71 | 71 | 76 | 77 | 80 | 83 |
| DR Summer - UT | 2 | 2 | 2 | 2 | 2 | 95 | 171 | 171 | 171 | 171 | 171 |
| DR Winter - UT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| DR Summer - WA | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| DR Winter - WA | 0 | 0 | 0 | 15 | 18 | 19 | 19 | 19 | 19 | 19 | 19 |
| DR Summer - WY | 12 | 12 | 12 | 12 | 15 | 28 | 47 | 47 | 47 | 47 | 47 |
| DR Winter - WY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

| Resource | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 |
|---|---|---|---|---|---|---|---|---|---|---|
| DR Summer - CA | 2 | 2 | 2 | 2 | 3 | 5 | 5 | 5 | 5 | 5 |
| DR Winter - CA | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| DR Summer - ID | 9 | 15 | 15 | 15 | 15 | 15 | 26 | 27 | 28 | 29 |
| DR Winter - ID | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| DR Summer - OR | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| DR Winter - OR | 94 | 94 | 106 | 110 | 133 | 136 | 136 | 145 | 145 | 153 |
| DR Summer - UT | 171 | 277 | 277 | 277 | 277 | 331 | 419 | 437 | 462 | 487 |
| DR Winter - UT | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 4 |
| DR Summer - WA | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 15 |
| DR Winter - WA | 27 | 27 | 33 | 34 | 35 | 36 | 36 | 36 | 36 | 38 |
| DR Summer - WY | 47 | 48 | 48 | 48 | 48 | 48 | 55 | 55 | 55 | 55 |
| DR Winter - WY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 |

Table D.4 also shows cumulative selections, but for energy efficiency instead of demand response, and in units of energy (MWh). These energy efficiency energy savings were converted from units of nameplate capacity selected by the IRP using the load shapes of bundled measures, as described in Chapter 7, and do not reflect first-year savings. For a corresponding view of cumulative energy efficiency selections but in units of capacity (MW), see Figure 9.8 in Chapter 9.

Table D.5 similarly shows energy efficiency selections in units of energy, but in terms of incremental, *first-year* energy savings (MWh), not cumulative. These vary from the incremental savings one would derive by subtracting year-over-year cumulative values in Table D.4 because the savings in Table D.5 apply capacity selections at the specific measure-level, leveraging non-bundled load shapes. Table D.5 is provided here to reflect how energy efficiency programs pursue energy efficiency measures in practice and design their offerings, bridging the gap between the proxy-based nature of the IRP and state-specific program implementation. Table D.4 and Table D.5 both exclude energy efficiency savings from the Home Energy Report program.

## Table D.4 – Cumulative Energy Efficiency Resource Selections (2025 IRP Preferred Portfolio)[6]

| Cumulative Energy Efficiency Energy (MWh) Selected by State and Year | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **State** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** | **2034** | **2035** |
| **CA** | 3,308 | 7,186 | 11,388 | 15,309 | 19,229 | 23,073 | 26,991 | 31,358 | 36,397 | 41,184 | 45,080 |
| **ID** | 17,544 | 42,512 | 65,097 | 89,893 | 116,455 | 143,426 | 171,556 | 201,714 | 232,221 | 262,131 | 291,754 |
| **OR** | 211,150 | 379,370 | 605,544 | 832,779 | 1,064,124 | 1,291,630 | 1,521,326 | 1,762,122 | 1,976,929 | 2,183,231 | 2,361,518 |
| **UT** | 272,934 | 573,161 | 817,755 | 1,108,311 | 1,403,990 | 1,714,640 | 1,932,749 | 2,340,414 | 2,817,643 | 3,313,862 | 3,701,566 |
| **WA** | 46,965 | 80,143 | 117,022 | 161,600 | 203,520 | 248,039 | 288,737 | 346,363 | 405,470 | 462,659 | 518,944 |
| **WY** | 41,384 | 83,765 | 144,686 | 211,034 | 271,750 | 328,182 | 375,624 | 446,392 | 520,343 | 593,883 | 663,919 |
| **Total System** | 593,286 | 1,166,137 | 1,761,493 | 2,418,926 | 3,079,068 | 3,748,989 | 4,316,983 | 5,128,363 | 5,989,003 | 6,856,950 | 7,582,781 |

| Cumulative Energy Efficiency Energy (MWh) Selected by State and Year | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **State** | **2036** | **2037** | **2038** | **2039** | **2040** | **2041** | **2042** | **2043** | **2044** | **2045** |
| **CA** | 49,487 | 51,672 | 54,611 | 57,310 | 59,478 | 61,566 | 62,793 | 64,775 | 66,426 | 67,394 |
| **ID** | 320,075 | 348,696 | 371,724 | 393,809 | 412,398 | 429,787 | 446,895 | 465,603 | 483,738 | 496,213 |
| **OR** | 2,526,114 | 2,692,592 | 2,880,693 | 3,057,127 | 3,231,248 | 3,361,769 | 3,483,475 | 3,667,107 | 3,815,294 | 3,965,895 |
| **UT** | 4,049,145 | 4,205,654 | 4,680,853 | 5,144,103 | 5,547,278 | 5,856,413 | 5,689,544 | 6,027,457 | 6,342,021 | 6,635,978 |
| **WA** | 573,179 | 617,869 | 664,707 | 702,340 | 732,534 | 759,948 | 760,498 | 789,514 | 810,692 | 830,752 |
| **WY** | 708,202 | 746,669 | 800,029 | 850,977 | 896,067 | 943,697 | 949,377 | 986,888 | 1,020,725 | 1,049,194 |
| **Total System** | 8,226,202 | 8,663,151 | 9,452,617 | 10,205,665 | 10,879,002 | 11,413,179 | 11,392,583 | 12,001,344 | 12,538,897 | 13,045,426 |

## Table D.5 – *First-Year* Energy Efficiency Resource Selections (2025 IRP Preferred Portfolio)

| Energy Efficiency Energy (1st Year Savings MWh) Selected by State and Year | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **State** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** | **2034** | **2035** |
| **California** | 3,308 | 3,878 | 4,278 | 3,858 | 3,837 | 3,760 | 3,872 | 3,954 | 4,670 | 4,453 | 3,749 |
| **Idaho** | 17,544 | 24,968 | 22,631 | 24,590 | 26,413 | 27,024 | 28,091 | 28,280 | 28,823 | 28,616 | 28,366 |
| **Oregon** | 211,150 | 168,220 | 227,146 | 230,505 | 233,662 | 233,917 | 231,092 | 225,755 | 216,770 | 195,204 | 188,456 |
| **Utah** | 272,934 | 300,226 | 245,311 | 280,532 | 290,280 | 306,640 | 342,771 | 330,772 | 371,694 | 386,792 | 395,179 |
| **Washington** | 46,965 | 33,177 | 36,986 | 44,044 | 41,252 | 43,767 | 45,340 | 50,434 | 53,981 | 55,377 | 54,949 |
| **Wyoming** | 41,384 | 42,381 | 61,100 | 64,424 | 60,306 | 57,409 | 61,607 | 65,029 | 65,474 | 63,699 | 62,256 |
| **Total System** | 594,713 | 572,851 | 597,452 | 647,953 | 655,750 | 672,518 | 712,771 | 704,224 | 741,413 | 734,142 | 732,955 |

| Energy Efficiency Energy (1st Year Savings MWh) Selected by State and Year | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **State** | **2036** | **2037** | **2038** | **2039** | **2040** | **2041** | **2042** | **2043** | **2044** | **2045** |
| **California** | 3,278 | 3,251 | 2,924 | 2,685 | 2,100 | 1,827 | 1,663 | 1,582 | 1,645 | 756 |
| **Idaho** | 27,509 | 26,368 | 21,080 | 20,231 | 18,922 | 17,621 | 17,586 | 15,513 | 14,796 | 11,289 |
| **Oregon** | 181,642 | 174,990 | 169,001 | 159,411 | 169,587 | 165,583 | 147,685 | 151,996 | 131,894 | 126,643 |
| **Utah** | 411,810 | 412,543 | 371,801 | 359,565 | 345,723 | 345,449 | 347,345 | 275,353 | 267,698 | 222,351 |
| **Washington** | 54,403 | 50,805 | 40,523 | 37,159 | 32,029 | 28,548 | 27,671 | 25,382 | 21,944 | 18,247 |
| **Wyoming** | 58,616 | 55,056 | 47,532 | 45,951 | 40,842 | 39,675 | 39,979 | 34,832 | 34,675 | 24,042 |
| **Total System** | 737,258 | 723,014 | 652,861 | 625,003 | 609,202 | 598,703 | 581,930 | 504,657 | 472,652 | 403,327 |

** First-year energy cannot be summed up to get the cumulative energy by year because the hourly shapes change from year to year.*

*** The period 2025-2026 represents planned energy efficiency and does not change between all 2025 IRP cases.*

[6] First-year energy may vary slightly from incremental values, i.e., subtracting cumulative energy from the prior year, due to hourly shapes of energy efficiency changing from year to year.

## Table D.6 –Energy Efficiency Selected Bundle Cost/KWh (2025 IRP Preferred Portfolio)[7]

| | Cost ($/kWh) | | | | | |
|---|---|---|---|---|---|---|
| | CA | ID | OR | UT | WA | WY |
| Cool1 | $ 0.05 | $ 0.05 | $ 0.05 | $ 0.05 | $ 0.10 | $ 0.06 |
| Cool2 | $ 0.08 | $ 0.08 | $ 0.06 | $ 0.06 | $ 0.17 | $ 0.08 |
| Cool3 | $ 0.14 | $ 0.25 | $ 0.14 | $ 0.10 | $ 0.37 | $ 0.14 |
| Cool4 | $ 0.24 | $ 2.25 | $ 0.17 | $ 0.13 | $ 2.30 | $ 1.32 |
| Cool5 | $ 0.48 | $ - | $ 0.43 | $ 0.17 | $ - | $ - |
| Cool6 | $ 0.72 | $ - | $ 0.66 | $ 0.22 | $ - | $ - |
| Cool7 | $ 2.10 | $ - | $ - | $ 0.36 | $ - | $ - |
| Cool8 | $ - | $ - | $ - | $ 0.97 | $ - | $ - |
| Cool9 | $ - | $ - | $ - | $ 1.76 | $ - | $ - |
| Heat1 | $ 0.11 | $ 0.06 | $ 0.06 | $ 0.10 | $ 0.09 | $ 0.05 |
| Heat2 | $ 0.20 | $ 0.08 | $ 0.05 | $ 0.20 | $ 0.12 | $ 0.09 |
| Heat3 | $ 0.36 | $ 0.14 | $ 0.06 | $ 0.27 | $ 0.21 | $ 0.22 |
| Heat4 | $ 0.62 | $ 0.18 | $ 0.08 | $ 0.43 | $ 0.41 | $ 0.43 |
| Heat5 | $ 0.99 | $ 0.17 | $ 0.09 | $ - | $ 0.54 | $ - |
| Heat6 | $ - | $ 0.23 | $ 0.21 | $ - | $ 1.17 | $ - |
| Heat7 | $ - | $ 0.51 | $ 0.35 | $ - | $ - | $ - |
| Summer1 | $ - | $ 0.03 | $ 0.04 | $ 0.05 | $ 0.06 | $ 0.04 |
| Summer10 | $ 0.30 | $ 0.25 | $ 0.14 | $ 0.68 | $ 0.22 | $ - |
| Summer11 | $ 0.63 | $ 0.21 | $ 0.08 | $ - | $ 0.29 | $ - |
| Summer12 | $ 1.05 | $ 0.89 | $ - | $ - | $ 0.34 | $ - |
| Summer13 | $ - | $ - | $ - | $ - | $ 0.52 | $ - |
| Summer14 | $ - | $ - | $ - | $ - | $ 1.37 | $ - |
| Summer2 | $ 0.08 | $ 0.04 | $ 0.04 | $ 0.04 | $ 0.07 | $ 0.05 |
| Summer3 | $ 0.10 | $ 0.06 | $ 0.05 | $ 0.06 | $ 0.08 | $ 0.06 |
| Summer4 | $ 0.12 | $ 0.07 | $ 0.06 | $ 0.07 | $ 0.09 | $ 0.09 |
| Summer5 | $ 0.13 | $ 0.06 | $ 0.06 | $ 0.08 | $ 0.11 | $ 0.13 |
| Summer6 | $ 0.13 | $ 0.11 | $ 0.06 | $ 0.10 | $ 0.14 | $ 0.20 |
| Summer7 | $ 0.22 | $ 0.10 | $ 0.06 | $ 0.13 | $ 0.15 | $ 0.67 |
| Summer8 | $ 0.17 | $ 0.12 | $ 0.06 | $ 0.19 | $ 0.17 | $ - |
| Summer9 | $ 0.23 | $ 0.13 | $ 0.09 | $ 0.17 | $ 0.21 | $ - |
| Winter1 | $ 0.15 | $ 0.05 | $ 0.06 | $ 0.08 | $ 0.28 | $ 0.04 |
| Winter10 | $ - | $ - | $ - | $ - | $ - | $ 0.52 |
| Winter2 | $ - | $ 0.27 | $ - | $ 0.28 | $ - | $ 0.05 |
| Winter3 | $ - | $ - | $ - | $ - | $ - | $ 0.07 |
| Winter4 | $ - | $ - | $ - | $ - | $ - | $ 0.10 |
| Winter5 | $ - | $ - | $ - | $ - | $ - | $ 0.12 |
| Winter6 | $ - | $ - | $ - | $ - | $ - | $ 0.12 |
| Winter7 | $ - | $ - | $ - | $ - | $ - | $ 0.18 |
| Winter8 | $ - | $ - | $ - | $ - | $ - | $ 0.22 |
| Winter9 | $ - | $ - | $ - | $ - | $ - | $ 0.34 |
| ZeroFlat | $ 0.01 | $ 0.01 | $ 0.01 | $ 0.01 | $ 0.00 | $ 0.01 |
| ZeroTemp | $ 0.02 | $ 0.02 | $ 0.03 | $ 0.03 | $ 0.02 | $ 0.02 |

[7] See Appendix M, stakeholder feedback form #57 (Utah Clean Energy). For detail by State/Bundle/Year see the supporting workpaper, "Tbl D.6-7, DSM Selection Bundle Costs by State-Year (SFF #57) - Preferred Portfolio (LT 155264 ST 157144).xlsx."

## Table D.6 –Energy Efficiency Selected Bundle Cost/KW (2025 IRP Preferred Portfolio)[8]

| | Cost ($/kW) | | | | | |
|---|---|---|---|---|---|---|
| | CA | ID | OR | UT | WA | WY |
| Cool1 | $ 34.44 | $ 99.60 | $ 39.10 | $ 46.42 | $ 58.81 | $ 45.71 |
| Cool2 | $ 62.79 | $ 151.49 | $ 47.85 | $ 64.59 | $ 171.18 | $ 81.58 |
| Cool3 | $ 110.32 | $ 341.55 | $ 59.43 | $ 98.17 | $ 384.37 | $ 153.56 |
| Cool4 | $ 211.48 | $ 3,207.09 | $ 102.67 | $ 112.22 | $ 1,862.57 | $ 1,118.48 |
| Cool5 | $ 305.54 | $ - | $ 350.07 | $ 149.08 | $ - | $ - |
| Cool6 | $ 470.02 | $ - | $ 729.84 | $ 188.43 | $ - | $ - |
| Cool7 | $ 1,445.21 | $ - | $ - | $ 298.15 | $ - | $ - |
| Cool8 | $ - | $ - | $ - | $ 899.33 | $ - | $ - |
| Cool9 | $ - | $ - | $ - | $ 1,567.26 | $ - | $ - |
| Heat1 | $ 118.63 | $ 79.46 | $ 60.56 | $ 110.77 | $ 109.56 | $ 68.60 |
| Heat2 | $ 214.28 | $ 117.77 | $ 50.73 | $ 224.15 | $ 151.09 | $ 117.18 |
| Heat3 | $ 386.70 | $ 191.18 | $ 61.16 | $ 269.11 | $ 254.15 | $ 298.04 |
| Heat4 | $ 690.00 | $ 246.74 | $ 41.02 | $ 443.25 | $ 503.58 | $ 537.41 |
| Heat5 | $ 1,056.17 | $ 231.95 | $ 49.21 | $ - | $ 631.65 | $ - |
| Heat6 | $ - | $ 296.21 | $ 144.47 | $ - | $ 1,433.15 | $ - |
| Heat7 | $ - | $ 702.88 | $ 294.78 | $ - | $ - | $ - |
| Summer1 | $ - | $ 149.27 | $ 255.86 | $ 301.41 | $ 262.11 | $ 198.72 |
| Summer10 | $ 2,040.47 | $ 1,388.55 | $ 339.80 | $ 4,486.44 | $ 1,376.70 | $ - |
| Summer11 | $ 3,626.01 | $ 1,487.96 | $ 458.89 | $ - | $ 2,042.88 | $ - |
| Summer12 | $ 5,178.58 | $ 5,447.65 | $ - | $ - | $ 2,535.65 | $ - |
| Summer13 | $ - | $ - | $ - | $ - | $ 3,446.85 | $ - |
| Summer14 | $ - | $ - | $ - | $ - | $ 9,501.19 | $ - |
| Summer2 | $ 504.17 | $ 234.72 | $ 255.15 | $ 262.19 | $ 323.76 | $ 283.12 |
| Summer3 | $ 601.57 | $ 267.45 | $ 244.48 | $ 333.57 | $ 467.09 | $ 398.33 |
| Summer4 | $ 629.21 | $ 316.92 | $ 271.13 | $ 468.89 | $ 445.69 | $ 559.25 |
| Summer5 | $ 655.98 | $ 362.60 | $ 282.17 | $ 467.20 | $ 726.66 | $ 807.15 |
| Summer6 | $ 818.95 | $ 479.70 | $ 299.45 | $ 510.05 | $ 891.95 | $ 1,134.83 |
| Summer7 | $ 541.08 | $ 650.65 | $ 360.69 | $ 882.82 | $ 1,069.57 | $ 4,615.21 |
| Summer8 | $ 1,111.37 | $ 719.15 | $ 290.70 | $ 1,104.57 | $ 1,143.29 | $ - |
| Summer9 | $ 1,470.95 | $ 764.59 | $ 459.74 | $ 1,072.76 | $ 1,364.76 | $ - |
| Winter1 | $ 1,122.07 | $ 361.68 | $ 426.69 | $ 644.23 | $ 2,183.03 | $ 347.96 |
| Winter10 | $ - | $ - | $ - | $ - | $ - | $ 3,982.36 |
| Winter2 | $ - | $ 2,125.34 | $ - | $ 2,294.71 | $ - | $ 415.94 |
| Winter3 | $ - | $ - | $ - | $ - | $ - | $ 524.62 |
| Winter4 | $ - | $ - | $ - | $ - | $ - | $ 803.17 |
| Winter5 | $ - | $ - | $ - | $ - | $ - | $ 972.07 |
| Winter6 | $ - | $ - | $ - | $ - | $ - | $ 882.43 |
| Winter7 | $ - | $ - | $ - | $ - | $ - | $ 1,514.27 |
| Winter8 | $ - | $ - | $ - | $ - | $ - | $ 1,660.83 |
| Winter9 | $ - | $ - | $ - | $ - | $ - | $ 2,754.61 |
| ZeroFlat | $ 63.46 | $ 38.41 | $ 64.72 | $ 83.06 | $ 4.41 | $ 53.18 |
| ZeroTemp | $ 22.11 | $ 56.30 | $ 29.95 | $ 49.69 | $ 27.01 | $ 16.05 |

[8] See Appendix M, stakeholder feedback form #57 (Utah Clean Energy). For detail by State/Bundle/Year see the supporting workpaper, "Tbl D.6-7, DSM Selection Bundle Costs by State-Year (SFF #57) - Preferred Portfolio (LT 155264 ST 157144).xlsx."

# APPENDIX E – GRID ENHANCEMENT

## Introduction

"Smart" grid enhancement is the application of advanced communications and controls applied to every aspect of the electric power system from regional real-time energy markets to distribution automation. The wide array of applications discussed in this appendix can be considered under the grid enhancement umbrella. PacifiCorp has identified specific areas for research and implementation that include practices such as joining the western day-ahead market and technologies such as dynamic line rating, phasor measurement units, distribution automation, advanced metering infrastructure (AMI), automated demand response and others.

PacifiCorp has reviewed relevant grid enhancement technologies for transmission and distribution systems that provide local and system benefits. When considering these technologies, advanced controls and communications often the most critical infrastructure decision. The company network must have relevant speed, reliability, and security to support applications such as the current real-time Western Energy Imbalance Market (WEIM), which optimizes the energy imbalances throughout the West by transferring energy between participants in 15-minute and five-minute intervals throughout the day.

Finally, PacifiCorp has focused on those technologies that present a positive benefit for customers, seeking to optimize the electrical grid when and where it is economically feasible, operationally beneficial and in the best interest of customers. PacifiCorp is committed to consistently evaluating emerging technologies for integration—when they are found to be appropriate investments. The company is working with state commissions to improve reliability, energy efficiency, customer service and integration of renewable resources by analyzing the total cost of ownership, performing thorough cost-benefit analyses, and reaching out to customers concerning grid enhancement applications. As industry advances and development continue, PacifiCorp can improve cost estimates and benefits of grid enhancement technologies that will assist in identifying the best-suited opportunities and applications for implementation.

## Regional Energy Markets

### Western Energy Imbalance Market

The company and the California Independent System Operator (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. It includes companies from a Canadian province and 10 states in the western United States — British Columbia, Arizona, California, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington and Wyoming — leveraging the California ISO advanced market systems to dispatch the least-cost resources every five minutes. The company continues to work with CAISO, existing and prospective WEIM entities and stakeholders to enhance market functionality and support market growth. The expansive footprint now represents 79% of load in the Western Interconnection. The WEIM has produced significant monetary benefits for its participant members ($5.5 billion total footprint-wide benefits as of March 31, 2024, accumulated since November 2014), quantified in the following categories:

- More efficient dispatch, both inter- and intraregional, by optimizing dispatch every 15-minute and every five-minute interval within and across the WEIM footprint
- Reduced renewable energy curtailment by allowing balancing authority areas to export renewable generation that would otherwise need to be curtailed; renewable resource curtailment has been reduced by 2.2 million MWh since 2015

### Extended Day Ahead Market

PacifiCorp has planned to build on the success of real-time energy market innovation by joining the new, voluntary, Western day-ahead market, (EDAM), developed by CAISO. The EDAM builds on the existing structure and proven success of the WEIM. Participation in the day-ahead market is designed to deliver significant reliability, economic and environmental benefits. The EDAM optimizes resources and transmission offered to the market and commits resources efficiently while conducting energy transfers to meet forecasted demand across the EDAM footprint. WEIM participants can extend their participation to incorporate EDAM but must notify CAISO of their participation and sign on for EDAM implementation.

Throughout 2022, PacifiCorp participated in a robust stakeholder process hosted by CAISO to provide input on market design. As a result, the EDAM design incorporated a resource sufficiency evaluation (RSE) and demonstration of transmission to ensure confidence in market transfers. EDAM participation is defined by a participant’s ability to pass the EDAM RSE, which prevents leaning on other market participants through a standardized criterion. The EDAM requires a transmission offering to support the EDAM participants’ RSE showing in addition to facilitating transfers across the EDAM footprint in the day-ahead timeframe. EDAM participants will continue to plan to meet projected load as done today and will retain the responsibilities of balancing and ensuring reliability within the WEIM. PacifiCorp along with three other large utilities have informed CAISO of their interest in joining the EDAM.

## Transmission Network and Operation Enhancements

### Advanced Protective Relays

The company is expanding its use and understanding of advanced protective relays. These devices are designed to remotely identify and report the distance and directionality of faults. PacifiCorp has come to recognize that these sensors can provide significantly more information beyond fault distance and directionality. For example, advanced protective relays provide near-real-time data on proper breaker functionality as well as oscillographic operation data that is especially valuable in managing inverter-based resources, like customer solar and wind farms. To ensure the company implements monitoring equipment with minimum potential disruption to customers, adoption is iterative: the company simulates data and events in a test environment to check settings and logic before implementation.

### Dynamic Line Rating

Dynamic line rating (DLR) is the application of sensors to transmission lines to indicate the real-time, current-carrying capacity of the lines in relation to thermal restrictions. Transmission line ratings are typically based on line-loading calculations given a set of worst-case weather assumptions, such as high ambient temperatures and low wind speeds. DLR allows an increase in current-carrying capacity of transmission lines, when more favorable weather conditions are present, without compromising safety. DLR has become increasingly relevant with higher shares of variable renewable energy (VRE) in the power system. By increasing the ampacity of transmission lines, DLR provides economic and technical benefits to all involved. FERC NOPR

(RM21-17-000) is calling to fully consider DLR and advanced power flow control devices in local and regional transmission planning processes.

PacifiCorp has been using DLR since 2014. The Standpipe–Platte project was implemented in 2014 and has delivered positive results as windy days are linked to increased wind power generation and increased transmission ratings. A DLR system determines the resulting cooling effect of the wind on the line. The current carrying capacity is then updated to a new weather-dependent line rating. The Standpipe–Platte 230 kilovolt (kV) transmission line is one of three lines in the Aeolus West transmission corridor and had been one of the lines that limits the corridor power transfer during high wind conditions. As a result of this project, nonsimultaneous path rating for the Western Electricity Coordinating Council (WECC)-defined Aeolus West path was increased. The DLR system on the Standpipe–Platte 230 kV line has been updated with a transmission line monitoring (TLM) system manufactured by Lindsey Systems.

Additionally, a new DLR system is being implemented on the existing Dave Johnston–Amasa–Heward–Shirley Basin 230 kV line as well as the Windstar–Shirley Basin 230 kV line as part of the Gateway West Segment D.1 Project. The Dave Johnston–Amasa–Heward–Shirley Basin 230 kV line connects two areas ((northeast and southeast Wyoming) with a high penetration of wind generation resources. Implementation of the DLR system will improve the link between those two areas to reduce the need for operational curtailments when wind patterns result in a variation in generation between the two areas, such as high winds in the northeast Wyoming area and moderate to low winds in the southeast Wyoming area. The DLR system will increase the transmission line steady-state rating under increased wind conditions and reduce instances and duration of associated generation curtailments while increasing power transfers between the two areas.

DLR and/or other grid-enhancing technologies (GET) will be evaluated for all future transmission needs as a means for increasing capacity in relation to traditional construction methods. DLR is only applicable for thermal constraints and only provides additional site-dependent capacity during finite time periods. It may or may not align with expected transmission needs of future projects. PacifiCorp will continue to look for opportunities to cost-effectively employ DLR systems similar to the one deployed on the Standpipe–Platte 230 kV, Dave Johnston–Amasa–Heward–Shirley Basin 230 kV line, and the Windstar–Shirley Basin 230 kV transmission lines.

**Digital Fault Recorders / Phasor Measurement Unit Deployment**

Phasor management units (PMU) provide sub-second data for voltage and current phasors. Digital fault recorders (DFR) have a shorter recording time with higher sampling rate to validate dynamic disturbance modeling. DFR/PMUs deliver dynamic PMU data to a centralized phasor data concentrator (PDC) storage server where offline analysis can be performed by transmission operators, planners, and protection & control engineers to validate system models. The PMU sub-second data can be used for North American Electric Reliability Corporation (NERC) MOD-033-1 standard event analysis and model verification. DFRs data can be used to validate dynamic disturbance modeling per NERC standard PRC-002-2. To comply with the MOD-033-1 and PRC-002-2, PacifiCorp has installed over 100 multifunctional DFRs, which include PMU functionality. The installations are at key transmission and generation facilities throughout the six-state service territory, generally placed on WECC-identified critical paths.

Transmission planners, in coordination with other Western Power Pool member utilities, use the phasor data quantities from actual system events to benchmark performance of steady-state and transient stability models of the interconnected transmission system and generating facilities.

Using a combination of phasor data from the PMUs and analog quantities currently available through Supervisory Control and Data Acquisition System (SCADA), transmission planners can set up the system models to accurately depict the transmission system before, during and following an event. Differences in simulated versus actual system performance are then evaluated to allow for enhancements and corrections to the system model.

DFR/PMU grid enhancement technology is being evaluated on several levels. Model validation procedures are being evaluated in conjunction with data and equipment availability to fulfill MOD-033-1. The process of validating the system model against a historical system outage event that includes the comparison of a planning power flow model to actual system behavior and the comparison of the planning dynamic model to actual system response is ongoing. PacifiCorp also continues to evaluate potential benefits of PMU installation and intelligent monitoring as the industry considers PMU in special protection, remedial action scheme and other roles that support transmission grid operators. PacifiCorp will continue to work with the CAISO Reliability Coordinator West to share data as appropriate. Finally, the technology is being evaluated in light of recently upgraded the PMU firmware, which has improved the data reliability and the extent of the data. The company is now engaging in preliminary evaluations on its potential use by grid operations and dispatch.

**Radio Frequency Line Sensors**

Like communicating faulted circuit indicators (CFCI) discussed later in this appendix, radio frequency (RF) line sensors are located along circuits (not in substations). Unlike CFCIs, RF line sensors are installed not on but adjacent to lines—2-4 feet from a conductor, outside the minimum approach distance. Where CFCIs evaluate magnetic fields to identify faults in amperage, RF line sensors monitor high-frequency radio waves that can be caused by physical damage to a line, for example a nicked conductor or failing insulator. While the physical damage may not be visible to the naked eye, the use of multiple RF line sensors with GPS clocks installed allows the devices to provide location information within 100 feet. The use of partial discharge cameras with arrays of high-frequency microphones further refines the problem and location. Smart technology that can detect physical degradation before it is obvious is a practical choice for strategically mitigating damage to aging infrastructure; the company is pursuing a pilot RF line sensor project on one transmission line in Oregon and California, involving 20 sensors. The equipment installation is substantially complete. (The final sensor will be installed in early 2025 once weather permits.) The company has begun collecting and evaluating the data and its potential uses. The data collection and analysis phase are currently planned for several years. If results are promising, PacifiCorp might expand beyond the pilot project sooner.

**Transmission CFCIs**

CFCIs, for both transmission and distribution, are grid enhancement devices installed directly on conductors; these devices use magnetic field measurements to provide fault indication. They offer real-time visibility and are increasingly valuable for ensuring system reliability, resiliency, and flexibility. CFCIs provide multiple grid management enhancements:

- Leverage real-time line information to augment predictive capability of existing OMS and reducing the time spent to locate, isolate, and restore power.
- Help determine safe switching procedures and support cost-effective capital improvement and maintenance plans.
- Improve optimization opportunities for capital costs and system losses by providing measurements of per-phase vector quantities for voltage and current.
- Identify service quality issues early and allow timely development and implementation of cost-effective mitigation.

PacifiCorp has adopted and is continuing to broadly deploy distribution level CFCIs. The Company is also beginning its adoption of CFCIs for use at the transmission level.

The steps necessary for a transmission level CFCI pilot have begun. PacifiCorp has completed a transmission CFCI request for proposals (RFP) and selected two vendors. The company plans to move forward with both vendors—given supply and development the company views this as a prudent choice.

## Distribution Automation and Reliability

### Distribution Automation / Fault Location, Isolation and Service Restoration

Distribution automation (DA) uses multiple technologies including sensors, switches, controllers, and communications networks that can work together to improve distribution system reliability. Fault location, isolation, and service restoration (FLISR) software can be used to control reclosers to automatically restore customers located downstream from trouble.

DA's ability to provide improved outage management with decreased restoration times after failure, operational efficiency, and peak load management using distributed resources and predictive equipment failure analysis based on complex data algorithms has been a company focus. PacifiCorp continues to evaluate different DA strategies to help determine which method is the best fit for a typical distribution system based on cost, cybersecurity, and scope of the DA effort.

In Oregon, PacifiCorp identified and performed cost-benefit analyses on 40 circuits. From this analysis two circuits in Lincoln City, Oregon, were selected to have a fault location, isolation, and service restoration (FLISR) system installed. The project was installed in 2019 and commissioning of the automation scheme conducted through 2020 in the distribution loop out of Devil's Lake substation in Lincoln City, Oregon. The company also moved its predeployment DA testing equipment to its Tech Ops center in Portland, Oregon, to expand open discussion between internal end users including operations, service crews and field technicians. Throughout the implementation of the Devil's Lake DA scheme, the company faced persistent challenges with communication over its existing AMI network. The company found the communication capability of AMI was not well-suited for a FLISR scheme and evaluated alternative solutions. The solution now uses fiber optic communication, which the company installed in a loop configuration to increase resiliency of the FLISR scheme's communication path. Despite communication issues in the early stages of its implementation, PacifiCorp can now remotely monitor and control these devices. The company has fault location and remote-control at Devil's Lake, and the FLISR scheme was implemented summer 2022.

Two additional FLISR schemes Portland and Medford are slated for completion early 2025. The vendor that programmed/developed the logic for all three projects has moved on to other work, creating code maintenance challenges. PacifiCorp is collaborating with the vendor in its long-term development of the next generation of this technology. Early evaluation shows the new FLISR graphical user interface is more elegant and the system overall easier to maintain.

### Distribution CFCIs

CFCI technology was described in greater detail earlier in this appendix. To briefly restate: CFCI devices are installed on distribution lines. They measure the magnetic field and provide fault indication. Their positive impacts are multiple and varied. In brief, CFCIs substantially improve real-time information exchange and reduce the time spent to locate, isolate, and restore power. PacifiCorp expects CFCIs to contribute towards SAIDI reductions as well as reduced carbon emissions due to decreased need for line patrols.

CFCI installation began as a conversation at PacifiCorp in 2017, became a pilot in 2019-2020, and entered broad deployment in 2021. There are now approximately 4,000 CFCIs on the company distribution network, mainly in high fire risk areas. Roughly 3,500 more are planned for installation before the end of 2025.

Since broad deployment, company field staff have come to increasingly rely on CFCIs. The effectiveness of these devices for field operations and dispatch has become clear relatively quickly. For field operations, CFCIs to locate the fault more quickly, improving situational awareness, fault location and restoration. For dispatch, CFCIs have enabled faster information transfer to the field— data is coming through the OMS/EMS systems more quickly.

**Distribution Substation Metering**

Substation monitoring and measurement of various electrical attributes were identified as a necessity due to the increasing complexity of distribution planning driven by growing levels of primarily solar generation as distributed energy resources. Enhanced measurements improve visibility into loading levels and generation hosting capacity as well as load shapes, customer usage patterns, and information about reliability and power quality events.

In 2017, an advanced substation metering project was initiated to provide an affordable option for gathering required substation and circuit data at locations where SCADA is unavailable and/or uneconomical. SCADA has been the preferred form of gathering load profile data from distribution circuits, however SCADA systems can be expensive to install, and additional equipment is required to provide the data needed to perform distribution system and power quality analysis. When system data rather than data and control is important, SCADA is no longer the best option.

Engineers require data to perform analysis of system loading and diagnose waveform and harmonics issues; the lack of data can inhibit accurate system evaluations. The substation metering project recognizes that system data has value independent of control and current system status. The advanced substation metering pilot is intended to provide an affordable option for gathering required distribution system data.

The advanced substation metering project was intended to provide an affordable option for gathering required distribution system data. The company's work plan included:

- Finalize installation of advanced substation meters at distribution substations and document installations
- Ensure all substation meters installed as part of this program are enabled with remote communication capabilities.
- Refine a data management system (PQView) to automatically download, analyze and interpret data downloaded from all installed substation meters.

The power quality monitoring project initiated in Utah in 2019 expanded in 2023 to include 340 data sources across the company's six-state service territory that feed data to PQView, including reprogrammed revenue meters across the company's six-state territory. The data is used to monitor voltage harmonics, voltage balance, steady-state voltage levels, and to log voltage sag events. The company also deployed PQView software, a data analytics tool that provides users with a refined view of power quality information gathered from substation meters.

## Distributed Energy Resources

### Energy Storage Systems

CES includes large, centralized storage resources, such as electrochemical batteries, pumped hydroelectric energy storage, compressed air energy storage (CAES), gravity energy storage systems (such as weights moved by cranes, elevators or on rails), thermal energy storage, and electromechanical batteries (i.e., flywheels). One grid enhancement benefit is the ability to integrate renewable energy sources into an electricity delivery system. In contrast to dispatchable resources that are available on demand (but not above nameplate capacity), such as most fossil fuel generation, some renewable energy resources have intermittent generation output associated with environmental conditions, such as the presence of wind or sun. The generation output of these resources cannot be increased on demand or above the nameplate capacity and may have high opportunity costs when generation is decreased unexpectedly. Providing service to the electric grid may become progressively more challenging as the amount of the grid's energy requirements are increasingly served from these intermittent generation resources, particularly in the absence of incremental transmission construction. Two methods to fill this generation gap without the use of dispatchable resources are energy storage and DR programs, whether local or centralized.

PacifiCorp, through its 2023 IRP Renewables Report, compared, on a preliminary, screening-level, technical capabilities, capital costs and operations and maintenance costs of the following energy storage and combined renewable resource/energy storage technologies: Li-Ion and flow batteries; gravity energy storage systems (other than pumped hydro); CAES; solar, wind + energy storage; nuclear + thermal energy storage. Each technology of interest to the Company shall be evaluated by additional detailed studies to further investigate its direct application within long-term plans.

In addition to the evaluative efforts discussed above, in 2017, PacifiCorp filed the Energy Storage Potential Evaluation and Energy Storage Project proposal with the Oregon Public Utilities Commission (OPUC). This filing aligned with PacifiCorp's strategy and vision regarding the expansion and integration of renewable technologies. The company proposed a utility-owned, targeted energy storage system (ESS) pilot project. In 2019 PacifiCorp began project development and is progressing to build an ESS on a Hillview substation distribution circuit in Corvallis, Oregon. Due to issues finding a suitable location in Corvallis the company located a different location. The new location for the ESS is the Lakeport substation in Klamath Falls. The intent of this project is to integrate the ESS into the existing distribution system with the capability and flexibility to potentially advance to a future microgrid system.

Phase I of the project involves/involved installation of a single, utility-owned energy storage device to address historic outage characterization on a specific feeder, validate modeling through field test data, create a research platform and optimize energy storage controls and integration on the company network. The company contracted an owner's engineer to aid in project development and is progressing on the Phase I project to build an ESS at the Oregon Institute of Technology (OIT) on circuit SL49, fed from the Lakeport substation. The company contracted Powin Energy to provide the ESS. The intent of this project is to integrate the ESS into the existing distribution system with the capability and flexibility to potentially provide renewables integration support with OIT's solar generation. The project is scheduled to be constructed and placed into service in mid-2025. The minimum system size is:

- Energy requirement of 6 MWh
- Power requirement of 2 MW

Phase II of the project involves/involved the addition of an additional energy storage device to pilot distributed storage, optimize use cases per Phase I results, explore tariff structure and ownership models and continue research.

In 2020, PacifiCorp developed Community Resiliency programs in Oregon and California to expand customer and utility understanding of how the use of ESS equipment might increase the resilience of critical facilities. The initial pilot programs provided technical support and evaluation of potential options as well as grant funding for on-site battery storage systems. Over a dozen feasibility studies were delivered across the Company's service area in the two states. Two ESS systems have been installed in California with a third approved; one ESS is in the final stages of commissioning in Oregon. As part of more recent efforts related to PacifiCorp's Oregon Clean Energy Plan (CEP), the Company received approval to provide pathways of support for communities working to enhance resilience at critical facilities. This includes feasibility assessments, grant match funding and ongoing project support for renewable energy and BESS systems. This Pilot program will operate through 2027.

The PacifiCorp filing with FERC covering optional generation interconnection study assumptions for stand-alone electric storage resources was approved on February 28, 2023 (section 38.1 of the Open Access Transmission Tariff). The use of real-world operating assumptions for electric storage resources should lead to a more efficient interconnection process.

### Demand Response

PacifiCorp has operated demand response programs since the 1980's and has been expanding its offerings in the decades since. As demand response has been selected as a cost-effective demand-side management resource in the past several IRPs, including in PacifiCorp's western state service areas, the Company has rolled out demand response programs to a wide array of customers and to address multiple grid needs. Today, PacifiCorp has five demand response program categories (Cool Keeper, Wattsmart Batteries, Wattsmart Drive, Wattsmart Business Demand Response, and Irrigation Load Control) currently approved in multiple states. These programs reach all customer classes -- residential, commercial, industrial, and irrigation -- and are operating at different stages of deployment, from emerging, small-scale innovative pilots to large-scale mature programs, and in between. The Cool Keeper program alone, for example, provides more than 270 MWs of operating reserves to the system through the control of more than 118,000 air conditioning units. The Company has goals to grow and increase participation in each of these programs and will use the program for various use cases such as frequency response, contingency and peak load management.

For further discussion of PacifiCorp's demand response offerings, please reference Chapter 6, Chapter 7, and Appendix D.

### Dispatchable Customer Storage Resources

Based on the learnings from PacifiCorp's partnership with Soleil Lofts and Sonnen in 2018, the company developed the Wattsmart Battery Program, which was approved in Utah in October 2020 and in Idaho in April 2022.This innovative demand response program allows the company to manage behind-the-meter customer batteries for daily load cycling, backup power real-time grid needs such as peak load management, contingency reserves and frequency response. Customer-controlled batteries allow the company to maximize renewable energy when it is needed to support the electrical grid. The program has experienced exponential growth in its first four years of operation and has over 5,300 participating residential batteries as of Q4 2024 and has also been adding 8-12 large commercial batteries each year. PacifiCorp is exploring expanding the program into its service areas in Oregon and Washington starting in 2025.

## Transportation Electrification

Electric vehicle infrastructure programming has begun expanding across much the company's six-state service territory, touching Utah, California, Oregon, and Washington.

Following 2020 Utah legislation, in 2021 the Utah Public Service Commission approved the company's EV Infrastructure Program (EVIP). The program, which went into effect on January 1, 2022, is expected to last 10 years. The EVIP has five main elements: company-owned chargers, make-ready investments, innovative projects and partnerships, incentives, and outreach and education.

Multiple state of California government and utility commission efforts have required the company to address multiple efforts, including the 2022 adoption of California Rule 24, which requires utilities to provide line extensions to nonresidential EV charging stations at no cost to the applicant performing all civil and electrical work. On November 17, 2022, the California Public Utilities Commission issued D.22-11-040, which adopted a long-term TE policy framework that includes a third-party administered, statewide TE infrastructure program. PacifiCorp is participating by funding this statewide initiative and providing dedicated technical assistance services to commercial customers as they move to adopt EV infrastructure.

Oregon, over the last three years, has adopted numerous policies that are quickening the pace toward an electric transportation future. Oregon Senate Bill 1044, passed in 2019, established statewide zero-emission vehicle (ZEV) goals in five-year increments, reaching 90% of new sales by 2035, which equates to 2.5 million electric vehicles (EV) on the road. Advanced Clean Cars II rule, passed in December of 2022, requires 100% of new light-duty vehicles (LDV) be ZEVs or plug-in hybrid EVs by 2035, ramping up from an initial requirement that 35% of new LDVs be ZEVs in 2026. $101 million in National Electric Vehicle Infrastructure (NEVI) funding and additional state funding over seven years is being used to invest in electric vehicle supply equipment (EVSE) installation along major corridors and other roads, including a focus on rural areas, underserved communities, and multifamily housing locations. House Bill 2165 requires that all electricity companies (with ≥ 25,000 retail customers) recover the cost of prudent infrastructure investments in TE. The Oregon Department of Environmental Quality adopted the Advanced Clean Truck Rules 2021 in November 2021. In doing so, Oregon adopted California's emission standards for medium-duty vehicles (MDV) and heavy-duty vehicles (HDV), collectively referred to as MHDVs. This creates the ability to pursue the incentives to support the transition to zero emissions for medium- and heavy-duty sectors, and the target of 100% of new sales of MHDV being ZEV by 2050.

PacifiCorp proposed a portfolio of programs and pilots offering a range of support to different sectors working toward TE in its 2023 Transportation Electrification Plan (TEP). This included support for residential, commercial, and multifamily customers as well as customers pursuing electrification of fleets and MHDVs. The TE programs and pilots include:

- EVSE Rebate Pilot Program: Launched June of 2022, this program delivers rebates to residential, income-eligible, commercial, and multifamily customers to install Level 2 chargers.

- Outreach and Education Pilot Program: Provides future EV drivers with greater awareness and understanding of the benefits of electric transportation through outreach and educational platforms, self-service tools, ride-and-drive events and more. This program was also launched in June of 2022.
- Grant Programs: Since 2019, PacifiCorp has facilitated grants that support projects that advance electric transportation in underserved communities—a combination of competitive grants, matching grants and grant writing funded through Oregon Clean Fuels Program.
- Fleet Make Ready Pilot Program: This program, expected to launch in 2024, offers a behind-the-meter custom incentives to fleet customers that will support all make-ready infrastructure focused on commercial customers and inclusive of all vehicle class types.
- Public Utility-Owned Infrastructure Pilot Program: Launched in the third quarter of 2023, PacifiCorp will deploy utility-owned, publicly available charging infrastructure in underserved communities.
- Residential Managed Charging Pilot Program: This pilot, planned to launch later in 2024, actively manages EV loads through vehicle-and charger-enable protocols to shift charging load to off-peak times.
- To deliver the programs and pilots contained in this portfolio, PacifiCorp proposed a three-year budget totaling approximately $30 million, with each year containing increased annual spending. The TEP was approved in July 2023.

In Washington, Governor Jay Inslee signed House Bill 1091, low carbon fuel standard legislation, which limits the aggregate overall greenhouse gas emissions per unit of transportation fuel energy to 20% below 2017 levels by 2038. Electric utilities can opt into the program as credit generators and be assigned credits from residential EV charging, which the company has opted into. Revenue earned by selling these credits must be used for TE projects while compliance can be achieved through reducing the carbon intensity of fuel or buying credits. In addition, Washington Executive Order 21-04 sets targets for 100% of all state fleet light-duty vehicles to be electric by 2035 and medium- and heavy-duty vehicles to be electric by 2040. The Advanced Clean Cars II rule, passed in December 2022 also requires 100% of new LDVs be ZEVs or plug-in hybrid EVs by 2035. To support TE in its service area, Pacific Power received approval in October 2022 of its Washington Transportation Electrification Plan. As a follow-up the company filed applications for new grant programs, outreach and education programs and a managed charging program. The new communities grant program plans to be launched in mid-2024, while outreach and education and managed charging are finalizing vendor contracting and moving toward kickoff activities.

## Advanced Metering Infrastructure

Advanced metering infrastructure (AMI) is an integrated system of smart meters, communications networks, and data management systems that provide interval data available daily. This infrastructure can also provide advanced functionalities including remote connect/disconnect, outage detection and restoration signals, and support DA schemes. In 2016, PacifiCorp identified economical AMI solutions for California and Oregon that delivered tangible benefits to customers while minimizing the impact on consumer rates.

In 2019, PacifiCorp completed installation of the Itron Gen5 AMI system across the company's Oregon and California service territories. The AMI system consists of head-end software, FANs and approximately 680,000 meters. Interval energy usage data is provided to customers via the company's public websites and mobile apps. The project was completed on schedule and on budget.

In 2018, PacifiCorp awarded a contract to Itron for their OpenWay Riva AMI system in the states of Idaho and Utah. In early 2020, Itron proposed a change for the information technology (IT) and network systems, using their Gen5 system rather than the OpenWay system, while still deploying the more advanced Riva meter technology. Itron's Gen5 system has the same IT and network used in PacifiCorp's Oregon and California service territories. This solution aligns with Itron's future road map and provides PacifiCorp with a single operational system that will reduce cybersecurity issues and operating costs associated with maintaining separate systems. This solution provides a stronger, more flexible network coupled with a high-end metering solution.

The Utah/Idaho project involved upgrading the head-end software and installation of the Field Area Network (FAN) and approximately 325,000 new Itron Riva AMI meters for most customer classification and 1,700 FAN devices. This solution uses over 80% of the existing AMR meters in Utah to provide hourly interval data for residential customers as well as outage detection and restoration messaging. The project replaced all current meters in Idaho with new Itron Riva AMI meters as AMR was not fully deployed there. Furthermore, the project will leverage the customer communication tools developed for the Oregon and California AMI projects. The project was completed in 2023.

Financial analyses to extend AMI solutions to Washington and Wyoming were performed in 2019, 2020, 2023, and 2024, respectively. The analyses determined that moving these states to an AMI solution is not cost effective at this time.

## Outage Management Improvements

PacifiCorp advanced a new module in its outage management systems (OMS) that allows field responders to update outage data as they complete their work, using Mobile Workforce Management tools. This functionality is restricted to service transformer and customer meter devices, which comprise approximately half of the outages to which the company responds. This ensures more rapid, accurate and efficient updates to outage data, but still maintains the OMS topology as the method to manage line worker safety by having real-time access to elements that are energized and those that may be in an abnormal state.

Meter pinging and last-gasp outage management functionalities were put in place for the AMI system in Oregon and California and is now being used in Utah and Idaho. The company's system operations organization use meter ping functionality and last-gasp messages to augment customer calls and create outage tickets in the company's OMS. The company implemented business process changes to facilitate outage management functionality for single-service as well as large-scale outages. These changes have provided system operations with more flexibility to identify and respond to outages.

Intelligent line sensors will be installed on distribution circuits to provide service to critical facilities. For this project, critical facilities have been defined as major emergency facility centers such as hospitals, trauma centers, police, fire dispatch centers, etc. The information provided by the line sensors will allow control center operators to target restoration at critical facilities during major outages sooner than is currently possible. Full implementation of the project was completed in December 2021, concurrent with the completion of the AMI project.

## Future Grid Enhancements

The company continues to develop a strategy to attain long-term goals for grid modernization and grid enhancement-related activities to continually improve system efficiency, reliability, and safety, while providing a cost-effective service to our customers. The company will continue to monitor grid enhancement technologies and determine viability and applicability of implementation to the system. As tipping points to broader implementation occur, PacifiCorp will communicate with customers and stakeholders through a variety of methods, including this IRP as well as other regulatory mechanisms relevant to each state.

# APPENDIX F – FLEXIBLE RESERVE STUDY

## Introduction

For the 2025 IRP, PacifiCorp is continuing to use the methodology developed in its 2021 Flexible Reserve Study (FRS), which relied upon historical data from 2018-2019, as discussed below.[1]

The 2021 Flexible Reserve Study (FRS) estimated the regulation reserve required to maintain PacifiCorp's system reliability and comply with North American Electric Reliability Corporation (NERC) reliability standards. Because the FRS methodology accounts for changes in PacifiCorp's resource mix, both the quantity and cost of reserves has been updated for the 2025 IRP, as reported herein.

PacifiCorp operates two balancing authority areas (BAAs) in the Western Electricity Coordinating Council (WECC) NERC region--PacifiCorp East (PACE) and PacifiCorp West (PACW). The PACE and PACW BAAs are interconnected by a limited amount of transmission across a third-party transmission system and the two BAAs are each required to comply with NERC standards. PacifiCorp must provide sufficient regulation reserve to remain within NERC's balancing authority area control error (ACE) limit in compliance with BAL-001-2,[2] as well as the amount of contingency reserve required to comply with NERC standard BAL-002-WECC-2.[3] BAL-001-2 is a regulation reserve standard that became effective July 1, 2016, and BAL-002-WECC-3 is a contingency reserve standard that became effective June 28, 2021. Regulation reserve and contingency reserve are components of operating reserve, which NERC defines as "that capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection."[4]

Apart from disturbance events that are addressed through contingency reserve, regulation reserve is necessary to compensate for changes in load demand and generation output to maintain ACE within mandatory parameters established by the BAL-001-2 standard. The FRS estimates the amount of regulation reserve required to manage variations in load, variable energy resources[5] (VERs), and resources that are not VERs ("Non-VERs") in each of PacifiCorp's BAAs. Load, wind, solar, and Non-VERs were each studied because PacifiCorp's data indicates that these

[1] 2021 IRP Volume II, Appendix F (Flexible Reserve Study): https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021-irp/Volume%20II%20-%209.15.2021%20Final.pdf

[2] NERC Standard BAL-001-2, https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-001-2.pdf, which became effective July 1, 2016. ACE is the difference between a BAA's scheduled and actual interchange and reflects the difference between electrical generation and Load within that BAA.

[3] NERC Standard BAL-002-WECC-3, https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-002-WECC-3.pdf, which became effective June 28, 2021. BAL-002-WECC-3 removed the requirement that at least 50% of contingency reserves be held as "spinning" resources, as this was deemed redundant with frequency response requirements under BAL-003-2.

[4] Glossary of Terms Used in NERC Reliability Standards: https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf, updated March 8, 2023.

[5] VERs are resources that resources that: (1) are renewable; (2) cannot be stored by the facility owner or operator; and (3) have variability that is beyond the control of the facility owner or operator. *Integration of Variable Energy Resources*, Order No. 764, 139 FERC ¶ 61,246 at P 281 (2012) ("Order No. 764"); *order on reh'g*, Order No. 764-A, 141 FERC ¶ 61,232 (2012) ("Order No. 764-A"); *order on reh'g and clarification*, Order No. 764-B, 144 FERC ¶ 61,222 at P 210 (2013) ("Order No. 764-B").

components or customer classes place different regulation reserve burdens on PacifiCorp's system due to differences in the magnitude, frequency, and timing of their variations from forecasted levels.

The FRS is based on PacifiCorp operational data recorded from January 2018 through December 2019 for load, wind, solar, and Non-VERs. PacifiCorp's primary analysis focuses on the actual variability of load, wind, solar, and Non-VERs during 2018-2019. A supplemental analysis discusses how the total variability of the PacifiCorp system changes with varying levels of wind and solar capacity. The estimated regulation reserve amounts determined in this study represent the incremental capacity needed to ensure compliance with BAL-001-2 for a particular operating hour. The regulation reserve requirement covers variations in load, wind, solar, and Non-VERs, while implicitly accounting for the diversity between the different classes. An explicit adjustment is also made to account for diversity benefits realized because of PacifiCorp's participation in the Western Energy Imbalance Market (EIM) operated by the California Independent System Operator Corporation (CAISO).[6]

The methodology in the FRS is like that previously employed in PacifiCorp's 2019 IRP but was enhanced in two areas.[7] First, the historical period evaluated in the study was expanded to include two years, rather than one, to capture a larger sample of system conditions. Second, the methodology for extrapolating results for higher renewable resource penetration levels was modified to better capture the diversity between growing wind and solar portfolios.

The FRS results produce an hourly forecast of the regulation reserve requirements for each of PacifiCorp's BAAs that is sufficient to ensure the reliability of the transmission system and compliance with NERC and WECC standards. This regulation reserve forecast covers the combined deviations of the load, wind, solar and Non-VERs on PacifiCorp's system and varies as a function of the wind and solar capacity on PacifiCorp's system, as well as forecasted levels of wind, solar and load.

The regulation reserve requirement methodologies produced by the FRS are applied in production cost modeling to determine the cost of the reserve requirements associated with incremental wind and solar capacity. After a portfolio is selected, the regulation reserve requirements specific to that portfolio can be calculated and included in the study inputs, such that the production cost impact of the requirements is incorporated in the reported results. As a result, this production cost impact is dependent on the wind and solar resources in the portfolio as well as the characteristics of the dispatchable resources in the portfolio that are available to provide regulation reserves.

## Overview

The primary analysis in the FRS is to estimate the regulation reserve necessary to maintain compliance with NERC Standard BAL-001-2 given a specified portfolio of wind and solar resources. The FRS next calculates the cost of holding regulation reserve for incremental wind and solar resources. Finally, the FRS compares PacifiCorp's overall operating reserve requirements

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[6] Western Energy Imbalance Market. www.westerneim.com

[7] 2019 IRP Volume II, Appendix F (Flexible Reserve Study): https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019_IRP_Volume_II_Appendices_A-L.pdf

over the IRP study period, including both regulation reserve and contingency reserve, to its flexible resource supply.

The FRS estimates regulation reserve based on the specific requirements of NERC Standard BAL-001-2. It also incorporates the current timeline for EIM market processes, as well as EIM resource deviations and diversity benefits based on actual results. The FRS also includes adjustments to regulation reserve requirements to account for the changing portfolio of solar and wind resources on PacifiCorp's system and accounts for the diversity of using a single portfolio of regulation reserve resources to cover variations in load, wind, solar, and Non-VERs. A comparison of the results of the current analysis and that from previous IRPs is shown in Table F.1 and Table F.2. Flexible resource costs are portfolio dependent and vary over time. For more details, please refer to Figure F.11 – Incremental Wind and Solar Regulation Reserve Costs.

**Table F.1 - Portfolio Regulation Reserve Requirements**

| Case | Wind Capacity (MW) | Solar Capacity MW | Stand-alone Regulation Requirement (MW) | Portfolio Diversity Credit (%) | Regulation Requirement with Diversity (MW) |
|---|---|---|---|---|---|
| **CY2017 (2019 FRS)** | 2,750 | 1,021 | 994 | 47% | 531 |
| **2018-2019 (2021 FRS)** | 2,745 | 1,080 | 1,057 | 49% | 540 |

**Table F.2 - 2025 Flexible Reserve Costs as Compared to 2023 Costs, $/MWh**

| | Wind 2025 FRS (2024$) | Solar 2025 FRS (2024$) | Wind 2023 FRS (2024$) | Solar 2023 FRS (2024$) |
|---|---|---|---|---|
| **Study Period** | 2025-2045 | 2025-2045 | 2025-2042 | 2025-2042 |
| **Flexible Reserve Cost** | $0.47 | $0.66 | $1.22 | $1.53 |

## Flexible Resource Requirements

PacifiCorp's flexible resource needs are the same as its operating reserve requirements over the planning horizon for maintaining reliability and compliance with NERC regional reliability standards. Operating reserve generally consists of three categories: (1) contingency reserve (i.e., spinning, and supplemental reserve), (2) regulation reserve, and (3) frequency response reserve. Contingency reserve is capacity that PacifiCorp holds available to ensure compliance with the NERC regional reliability standard BAL-002-WECC-3.[8] Regulation reserve is capacity that PacifiCorp holds available to ensure compliance with the NERC Control Performance Criteria in BAL-001-2.[9] Frequency response reserve is capacity that PacifiCorp holds available to ensure

[8] NERC Standard BAL-002-WECC-3 – Contingency Reserve: https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-002-WECC-3.pdf
[9] NERC Standard BAL-001-2 – Real Power Balancing Control Performance: https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-001-2.pdf

compliance with NERC standard BAL-003-2.[10] Each type of operating reserve is further defined below.

## Contingency Reserve

**Purpose:** Contingency reserve may be deployed when unexpected outages of a generator or a transmission line occur. Contingency reserve may not be deployed to manage other system fluctuations such as changes in load or wind generation output.

**Volume:** NERC regional reliability standard BAL-002-WECC-3 specifies that each BAA must hold as contingency reserve an amount of capacity equal to three percent of load and three percent of generation in that BAA.

**Duration:** Except within 60 minutes of a qualifying contingency event, a BAA must maintain the required level of contingency reserve at all times. Generally, this means that up to 60 minutes of generation are required to provide contingency reserve, though successive outage events may result in contingency reserves being deployed for longer periods. To restore contingency reserves, other resources must be deployed to replace any generating resources that experienced outages, typically either market purchases or generation from resources with slower ramp rates.

**Ramp Rate:** Only up capacity available within ten minutes can be counted as contingency reserve. This can include "spinning" resources that are online and immediately responsive to system frequency deviations to maintain compliance with frequency response obligations under BAL-003-1.1, as well as from "non-spinning" resources that do not respond immediately, though they must still be fully deployed in ten minutes.[11]

## Regulation Reserve

**Purpose:** NERC standard BAL-001-2, which became effective July 1, 2016, does not specify a regulation reserve requirement based on a simple formula, but instead requires utilities to hold sufficient reserve to meet specified control performance standards. The primary requirement relates to area control error ("ACE"), which is the difference between a BAA's scheduled and actual interchange and reflects the difference between electrical generation and load within that BAA. Requirement 2 of BAL-001-2 defines the compliance standard as follows:

> *Each Balancing Authority shall operate such that its clock-minute average of Reporting ACE does not exceed its clock-minute Balancing Authority ACE Limit (BAAL) for more than 30 consecutive clock-minutes…*

In addition, Requirement 1 of BAL-001-2 specifies that PacifiCorp's Control Performance Standard 1 ("CPS1") score must be greater than equal to 100 percent for each preceding 12 consecutive calendar month period, evaluated monthly. The CPS1 score compares PacifiCorp's

[10] NERC Standard BAL-003-2 — Frequency Response and Frequency Bias Setting: https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-003-2.pdf

[11] While the minimum spinning reserve obligation previously contained within BAL-002-WECC-2a was retired due to redundancy with frequency response obligations under BAL-003-2, PacifiCorp's 2023 IRP does not explicitly model the frequency response obligation and retains the spinning obligation to ensure a supply of rapidly responding resources is maintained.

ACE with interconnection frequency during each clock minute. A higher score indicates PacifiCorp's ACE is helping interconnection frequency, while a lower score indicates it is hurting interconnection frequency. Because CPS1 is averaged and evaluated monthly, it does not require a response to every ACE event but rather requires that PacifiCorp meet a minimum aggregate level of performance in each month. Regulation reserve is thus the capacity that PacifiCorp holds available to respond to changes in generation and load to manage ACE within the limits specified in BAL-001-2.

**Volume:** NERC standard BAL-001-2 does not specify a regulation reserve requirement based on a simple formula but instead requires utilities to hold sufficient reserve to meet performance standards as discussed above. The FRS estimates the regulation reserve necessary to meet Requirement 2 by compensating for the combined deviations of the load, wind, solar and Non-VERs on PacifiCorp's system. These regulation reserve requirements are discussed in more detail later in the study.

**Ramp Rate:** Because Requirement 2 includes a 30-minute time limit for compliance, ramping capability that can be deployed within 30 minutes contributes to meeting PacifiCorp's regulation reserve requirements. The reserve for CPS1 is not expected to be incremental to the need for compliance with Requirement 2 but may require that a subset of resources held for Requirement 2 be able to make frequent rapid changes to manage ACE relative to interconnection frequency.

**Duration:** PacifiCorp is required to submit balanced load and resource schedules as part of its participation in EIM. PacifiCorp is also required to submit resources with up flexibility and down flexibility to cover uncertainty and expected ramps across the next hour. Because forecasts are submitted prior to the start of an hour, deviations can begin before an hour starts. As a result, a flexible resource might be called upon for the entire hour. To continue providing flexible capacity in the following hour, energy must be available in storage for that hour as well. The likelihood of deploying for two hours or more for reliability compliance (as opposed to economics) is expected to be small.

## Frequency Response Reserve

**Purpose:** NERC standard BAL-003-2 specifies that each BAA must arrest frequency deviations and support the interconnection when frequency drops below the scheduled level. When a frequency drop occurs because of an event, PacifiCorp will deploy resources that increase the net interchange of its BAAs and the flow of generation to the rest of the interconnection.

**Volume:** When a frequency drop occurs, each BAA is expected to deploy resources that are at least equal to its frequency response obligation. The incremental requirement is based on the size of the frequency drop and the BAA's frequency response obligation, expressed in megawatt (MW)/0.1 Herts (Hz). To comply with the standard, a BAA's median measured frequency response during a sampling of under-frequency events must be equal to or greater than its frequency response obligation. PacifiCorp's 2024 frequency response obligation was 21.7 MW/0.1Hz for PACW, and 62.9 MW/0.1Hz for PACE.[12] PacifiCorp's combined obligation amounts to 84.6 MW for a frequency drop of 0.1 Hz, or 253.8 MW for a frequency drop of 0.3 Hz.

[12] NERC. BAL-003-2 Frequency Response Obligation Allocation and Minimum Frequency Bias Settings for Operating Year 2022.

The performance measurement for contingency reserve under the Disturbance Control Standard (BAL-002-3)[13], allows for recovery to the lesser of zero or the ACE value prior to the contingency event, so increasing ACE above zero during a frequency event reduces the additional deployment needed if a contingency event occurs. Because contingency, regulation, and frequency events are all relatively infrequent, they are unlikely to occur simultaneously. Because the frequency response standard is based on median performance during a year, overlapping requirements that reduced PacifiCorp's response during a limited number of frequency events would not impact compliance.

As a result, any available capacity not being used for generation is expected to contribute to meeting PacifiCorp's frequency response obligation, up to the technical capability of each unit, including that designated as contingency or regulation reserves. Frequency response must occur very rapidly, and a generating unit's capability is limited based on the unit's size, governor controls, and available capacity, as well as the size of the frequency drop. As a result, while a few resources could hold a large amount of contingency or regulation reserve, frequency response may need to be spread over a larger number of resources. Additionally, only resources that have active and tuned governor controls as well as outer loop control logic will respond properly to frequency events.

**Ramp Rate:** Frequency response performance is measured over a period of seconds, amounting to under a minute. Compliance is based on the average response over the course of an event. As a result, a resource that immediately provides its full frequency response capability will provide the greatest contribution. That same resource will contribute a smaller amount if it instead ramps up to its full frequency response capability over the course of a minute or responds after a lag.

**Duration:** Frequency response events are less than one minute in duration.

## Black Start Requirements

Black start service is the ability of a generating unit to start without an outside electrical supply and is necessary to help ensure the reliable restoration of the grid following a blackout. At this time, PACW grid restoration would occur in coordination with Bonneville Power Administration black start resources. The Gadsby combustion turbine resources can support grid restoration in PACE. PacifiCorp has not identified any incremental needs for black start service during the IRP study period.

## Ancillary Services Operational Distinctions

In actual operations, PacifiCorp identifies two types of flexible capacity as part of its participation in the EIM. The contingency reserve held on each resource is specifically identified and is not available for economic dispatch within the EIM. Any remaining flexible capacity on participating resources that is not designated as contingency reserve can be economically dispatched in EIM based on its operating cost (i.e., bid) and system requirements and can contribute to meeting regulation reserve obligations. Because of this distinction, resources must either be designated as

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https://www.nerc.com/comm/OC/RS%20Landing%20Page%20DL/Frequency%20Response%20Standard%20Resources/BA_FRO_Allocations_for_OY2024.pdf

[13] NERC Standard BAL-002-3 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event: https://www.nerc.com/pa/Stand/Reliability Standards/BAL-002-3.pdf

contingency reserve or as regulation reserve. Contingency events are relatively rare while opportunities to deploy additional regulation reserve in EIM occur frequently. As a result, PacifiCorp typically schedules its lowest-cost flexible resources to serve its load and blocks off capacity on its highest-cost flexible resources to meet its contingency obligations, subject to any ramping limitations at each resource. This leaves resources with moderate costs available for dispatch up by EIM, while lower-cost flexible resources remain available to be dispatched down by EIM.

## Regulation Reserve Data Inputs

### Overview

This section describes the data used to determine PacifiCorp's regulation reserve requirements. To estimate PacifiCorp's required regulation reserve amount, PacifiCorp must determine the difference between the expected load and resources and actual load and resources. The difference between load and resources is calculated every four seconds and is represented by the ACE. ACE must be maintained within the limits established by BAL-001-2, so PacifiCorp must estimate the amount of regulation reserve that is necessary to maintain ACE within these limits.

To estimate the amount of regulation reserve that will be required in the future, the FRS identifies the scheduled use of the system as compared to the actual use of the system during the study term. For the baseline determination of scheduled use for load and resources, the FRS used hourly base schedules. Hourly base schedules are the power production forecasts used for imbalance settlement in the EIM and represent the best information available concerning the upcoming hour.[14]

The deviation from scheduled use was derived from data provided through participation in the EIM. The deviations of generation resources in EIM were measured on a five-minute basis, so five-minute intervals are used throughout the regulation reserve analysis.

EIM base schedule and deviation data for each wind, solar and Non-VER transaction point was downloaded using the SettleCore application, which is populated with data provided by the CAISO. Since PacifiCorp's implementation of EIM on November 1, 2014, PacifiCorp requires certain operational forecast data from all its transmission customers pursuant to the provisions of Attachment T to PacifiCorp's Federal Energy Regulatory Commission (FERC) approved Open Access Transmission Tariff (OATT). This includes EIM base schedule data (or forecasts) from all resources included in the EIM network model at transaction points. EIM base schedules are submitted by transmission customers with hourly granularity, and are settled using hourly data for load, and fifteen-minute and five-minute data for resources. A primary function of the EIM is to

[14] The CAISO, as the market operator for the EIM, requests base schedules at 75 minutes (T-75) prior to the hour of delivery. PacifiCorp's transmission customers are required to submit base schedules by 77 minutes (T-77) prior to the hour of delivery – two minutes in advance of the EIM Entity deadline. This allows all transmission customer base schedules enough time to be submitted into the EIM systems before the overall deadline of T-75 for the entirety of PacifiCorp's two BAAs. The base schedules are due again to CAISO at 55 minutes (T-55) prior to the delivery hour and can be adjusted up until that time by the EIM Entity (i.e., PacifiCorp Grid Operations). PacifiCorp's transmission customers are required to submit updated, final base schedules no later than 57 minutes (T-57) prior to the delivery hour. Again, this allows all transmission customer base schedules enough time to be submitted into the EIM systems before the overall deadline of T-55 for the entirety of PacifiCorp's two BAAs. Base schedules may be finally adjusted again, by the EIM Entity only, at 40 minutes (T-40) prior to the delivery hour in response to CAISO sufficiency tests. T-40 is the base schedule time point used throughout this study.

measure load and resource imbalance (or deviations) as the difference between the hourly base schedule and the actual metered values.

A summary of the data gathered for this analysis is listed below, and a more detailed description of each type of source data is contained in the following subsections.

**Source data:**

- Load data
    - Five-minute interval actual load
    - Hourly base schedules

- VER data
    - Five-minute interval actual generation
    - Hourly base schedules

- Non-VER data
    - Five-minute interval actual generation
    - Hourly base schedules

## Load Data

The load class represents the aggregate firm demand of end users of power from the electric system. While the requirements of individual users vary, there are diurnal and seasonal patterns in aggregated demand. The load class can generally be described to include three components: (1) average load, which is the base load during a particular scheduling period; (2) the trend, or "ramp," during the hour and from hour-to-hour; and (3) the rapid fluctuations in load that depart from the underlying trend. The need for a system response to the second and third components is the function of regulation reserve in order to ensure reliability of the system.

The PACE BAA includes several large industrial loads with unique patterns of demand. Each of these loads is either interruptible at short notice or includes behind the meter generation. Due to their large size, abrupt changes in their demand are magnified for these customers in a manner which is not representative of the aggregated demand of the large number of small customers which make up most PacifiCorp's loads.

In addition, interruptible loads can be curtailed if their deviations are contributing to a resource shortfall. Because of these unique characteristics, these loads are excluded from the FRS. This treatment is consistent with that used in the CAISO load forecast methodology (used for PACE and PACW operations), which also nets these interruptible customer loads out of the PACE BAA.

Actual average load data was collected separately for the PACE and PACW BAAs for each five-minute interval. Load data has not been adjusted for transmission and distribution losses.

## Wind and Solar Data

The wind and solar classes include resources that: (1) are renewable; (2) cannot be stored by the facility owner or operator; and (3) have variability that is beyond the control of the facility owner or operator.[15] Wind and solar, in comparison to load, often have larger upward and downward fluctuations in output that impose significant and sometimes unforeseen challenges when attempting to maintain reliability. For example, as recognized by FERC in Order No. 764, "Increasing the relative amount of [VERs] on a system can increase operational uncertainty that the system operator must manage through operating criteria, practices, and procedures, *including the commitment of adequate reserves*."[16] The data included in the FRS for the wind and solar classes include all wind and solar resources in PacifiCorp's BAAs, which includes: (1) third-party resources (OATT or legacy contract transmission customers); (2) PacifiCorp-owned resources; and (3) other PacifiCorp-contracted resources, such as qualifying facilities, power purchases, and exchanges. In total, the FRS study period includes an average of 2,745 megawatts of wind and 1,080 megawatts of solar.

## Non-VER Data

The Non-VER class is a mix of thermal and hydroelectric resources and includes all resources which are not VERs, and which do not provide either contingency or regulation reserve. Non-VERs, in contrast to VERs, are often more stable and predictable. Non-VERs are thus easier to plan for and maintain within a reliable operating state. For example, in Order No. 764, FERC suggested that many of its rules were developed with Non-VERs in mind and that such generation "could be scheduled with relative precision."[17]The output of these resources is largely in the control of the resource operator, particularly when considered within the hourly timeframe of the FRS. The deviations by resources in the Non-VER class are thus significantly lower than the deviations by resources in the wind class. The Non-VER class includes third-party resources (OATT or legacy transmission customers); many PacifiCorp-owned resources; and other PacifiCorp-contracted resources, such as qualifying facilities, power purchases, and exchanges. In total, the FRS includes 2,202 megawatts of Non-VERs.

In the FRS, resources that provide contingency or regulation reserve are considered a separate, dispatchable resource class. The dispatchable resource class compensates for deviations resulting from other users of the transmission system in all hours. While non-dispatchable resources may offset deviations in loads and other resources in some hours, they are not in the control of the system operator and contribute to the overall requirement in other hours. Because the dispatchable resource class is a net provider rather than a user of regulation reserve service, its stand-alone regulation reserve requirement is zero (or negative), and its share of the system regulation reserve requirement is also zero. The allocation of regulation reserve requirements and diversity benefits is discussed in more detail later in the study.

# Regulation Reserve Data Analysis and Adjustment

## Overview

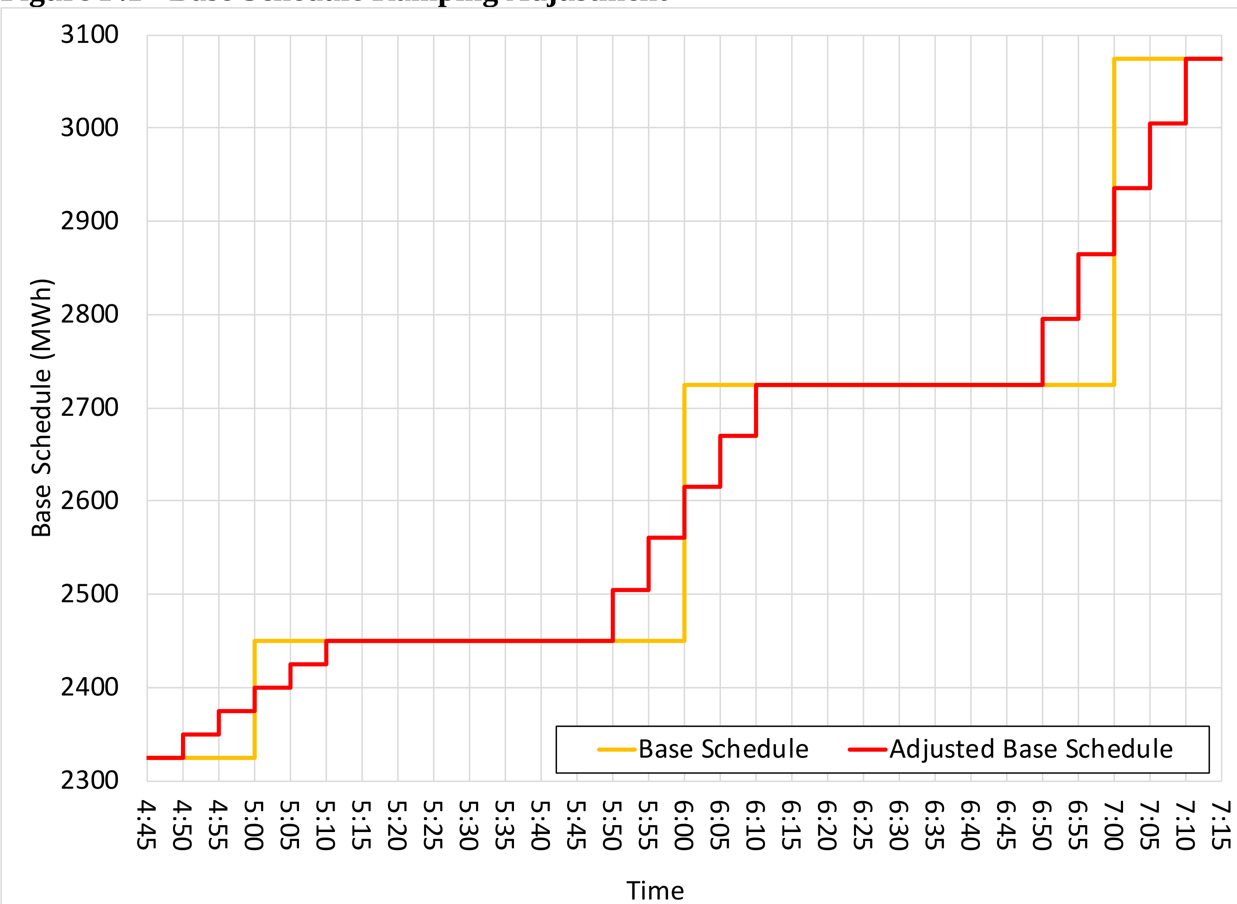
This section provides details on adjustments made to the data to align the ACE calculation with actual operations, and address data issues.

[15] Order No. 764 at P 281; Order No. 764-B at P 210.
[16] Order No. 764 at P 20 (emphasis added).
[17] *Id.* at P 92.

## Base Schedule Ramping Adjustment

In actual operations, PacifiCorp's ACE calculation includes a linear ramp from the base schedule in one hour to the base schedule in the next hour, starting ten-minutes before the hour and continuing until ten-minutes past the hour. The hourly base schedules used in the study are adjusted to reflect this transition from one hour to the next. This adjustment step is important because, to the extent actual load or generation is transitioning to the levels expected in the next hour, the adjusted base schedules will result in reduced deviations during these intervals, potentially reducing the regulation reserve requirement. Figure F.1 below illustrates the hourly base schedule and the ramping adjustment. The same calculation applies to all base schedules: Load, Wind, Non-VERs, and the combined portfolio.

**Figure F.1 - Base Schedule Ramping Adjustment**




## Data Corrections

The data extracted from PacifiCorp's systems for, wind, solar and Non-VERs was sourced from CAISO settlement quality data. This data has already been verified for inconsistencies as part of the settlement process and needs minimal cleaning as described below. Regarding five-minute interval load data from the PI Ranger system, intervals were excluded from the FRS results if any five-minute interval suffered from at least one of the data anomalies that are described further below:

**Load**:

- Telemetry spike/poor connection to meter
- Missing meter data
- Missing base schedules

**VERs:**
- Curtailment events

Load in PacifiCorp's BAAs changes continuously. While a BAA could potentially maintain the exact same load levels in two five-minute intervals in a row, it is extremely unlikely for the exact same load level to persist over longer time frames. When PacifiCorp's energy management system (EMS) load telemetry fails, updated load values may not be logged, and the last available load measurement for the BAA will continue to be reported.

Rapid spikes in load telemetry either up or down are unlikely to be the result of conditions which require deployment of regulation reserve, particularly when they are transient. Such events could be a result of a transmission or distribution outage, which would allow for the deployment of contingency reserve, and would not require deployment of regulation reserve. Such events are also likely to be a result of a single bad load measurement. Load telemetry spike irregularities were identified by examining the intervals with the largest changes from one interval to the next, either up or down. Intervals with inexplicably large and rapid changes in load, particularly where the load reverts within a short period, were assumed to have been covered through contingency reserve deployment or to reflect inaccurate load measurements. Because they do not reflect periods that require regulation reserve deployment, such intervals are excluded from the analysis. During the study period, in PACW 15 minutes' worth of telemetry spikes were excluded while no telemetry spikes were observed in PACE. There were also 10 minutes' worth of missing load meter data, and 82 hours of missing load base schedules.

The available VER data includes wind curtailment events which affect metered output. When these curtailments occur, the CAISO sends data, by generator, indicating the magnitude of the curtailment. This data is layered on top of the actual meter data to develop a proxy for what the metered output would have been if the generator were not curtailed. Regulation reserve requirements are calculated based on the shortfall in actual output relative to base schedules. By adding back curtailed volumes to the actual metered output, the shortfall relative to base schedules is reduced, as is the regulation reserve requirement. This is reasonable since the curtailment is directed by the CAISO or the transmission system operator to help maintain reliable operation, so it should not exacerbate the calculated need for regulation reserves.

After review of the data for each of the above anomaly types, and out of 210,216 five-minute intervals evaluated, approximately 1,000 five-minute intervals, or 0.5% of the data, was removed due to data errors. While cleaning up or replacing anomalous hours could yield a more complete data set, determining the appropriate conditions in those hours would be difficult and subjective. By removing anomalies, the FRS sample is smaller but remains reflective of the range of conditions PacifiCorp experiences, including the impact on regulation reserve requirements of weather events experienced during the study period.

# Regulation Reserve Requirement Methodology

## Overview

This section presents the methodology used to determine the initial regulation reserve needed to manage the load and resource balance within PacifiCorp's BAAs. The five-minute interval load and resource deviation data described above informs a regulation reserve forecast methodology that achieves the following goals:

- Complies with NERC standard BAL-001-2;
- Minimizes regulation reserve held; and
- Uses data available at time of EIM base schedule submission at T-40.[18]

The components of the methodology are described below, and include:

- Operating Reserve: Reserve Categories;
- Calculation of Regulation Reserve Need;
- Balancing Authority ACE Limit: Allowed Deviations;
- Planning Reliability Target: Loss of Load Probability ("LOLP"); and
- Regulation Reserve Forecast: Amount Held.

Following the explanation below of the components of the methodology, the next section details the forecasted amount of regulation reserve for:

- Wind;
- Solar;
- Non-VERs; and
- Load.

## Components of Operating Reserve Methodology

**Operating Reserve: Reserve Categories**

Operating reserve consists of three categories: (1) contingency reserve, (2) regulation reserve, and (3) frequency response reserve. These requirements must be met by resources that are incremental to those needed to meet firm system demand. The purpose of the FRS is to determine the regulation reserve requirement. The contingency reserve and frequency response requirements are defined formulaically by their respective reliability standards.

Of the three categories of reserve referenced above, the FRS is primarily focused on the requirements associated with regulation reserve. Contingency reserve may not be deployed to manage other system fluctuations such as changes in load or wind generation output. Because deviations caused by contingency events are covered by contingency reserve rather than regulation reserve, they are excluded from the determination of the regulation reserve requirements. Because frequency response reserve can overlap with that held for contingency and regulation reserve requirements it is similarly excluded from the determination of regulation reserve requirements.

[18] *See* footnote 12 above for explanation of PacifiCorp's use of the T-40 base schedule time point in the FRS.

The types of operating reserve and relationship between them are further defined in in the Flexible Resource Requirements section above.

Regulation reserve is capacity that PacifiCorp holds available to ensure compliance with the NERC Control Performance Criteria in BAL-001-2, which requires a BAA to carry regulation reserve incremental to contingency reserve to maintain reliability.[19] The regulation reserve requirement is not defined by a simple formula, but instead is the amount of reserve required by each BAA to meet specified control performance standards. Requirement two of BAL-001-2 defines the compliance standard as follows:

> *Each Balancing Authority shall operate such that its clock-minute average of Reporting ACE does not exceed its clock-minute Balancing Authority ACE Limit (BAAL) for more than 30 consecutive clock-minutes…*

PacifiCorp has been operating under BAL-001-2 since March 1, 2010, as part of a NERC Reliability-Based Control field trial in the Western Interconnection, so PacifiCorp had experience operating under the standard, even before it became effective on July 1, 2016.

The three key elements in BAL-001-2 are: (1) the length of time (or "interval") used to measure compliance; (2) the percentage of intervals that a BAA must be within the limits set in the standard; and (3) the bandwidth of acceptable deviation used under each standard to determine whether an interval is considered out of compliance. These changes are discussed in further detail below.

The first element is the length of time used to measure compliance. Compliance under BAL-001-2 is measured over rolling thirty-minute intervals, with 60 overlapping periods per hour, some of which include parts of two clock-hours. In effect, this means that every minute of every hour is the beginning of a new, thirty-minute compliance interval under the new BAL-001-2 standard. If ACE is within the allowed limits at least once in a thirty-minute interval, that interval is in compliance, so only the minimum deviation in each rolling thirty-minute interval is considered in determining compliance. As a result, PacifiCorp does not need to hold regulation reserve for deviations with duration less than 30 minutes.

The second element is the number of intervals where deviations are allowed to be outside the limits set in the standard. BAL-001-2 requires 100 percent compliance, so deviations must be maintained within the requirement set by the standard for all rolling thirty-minute intervals.

The third element is the bandwidth of acceptable deviation before an interval is considered out of compliance. Under BAL-001-2, the acceptable deviation for each BAA is dynamic, varying as a function of the frequency deviation for the entire interconnect. When interconnection frequency exceeds 60 Hz, the dynamic calculation does not require regulation resources to be deployed regardless of a BAA's ACE. As interconnection frequency drops further below 60 Hz, a BAA's permissible ACE shortfall is increasingly restrictive.

**Planning Reliability Target: Loss of Load Probability**

When conducting resource planning, it is common to use a reliability target that assumes a specified loss of load probability (LOLP). In effect, this is a plan to curtail firm load in rare

[19] NERC Standard BAL-001-2, https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-001-2.pdf

circumstances, rather than acquiring resources for extremely unlikely events. The reliability target balances the cost of additional capacity against the benefit of incrementally more reliable operation. By planning to curtail firm load in the rare event of a regulation reserve shortage, PacifiCorp can maintain the required 100 percent compliance with the BAL-001-2 standard and the Balancing Authority ACE Limit. This balances the cost of holding additional regulation reserve against the likelihood of regulation reserve shortage events.

The FRS assumes that a regulation reserve forecasting methodology that results in 0.50 loss of load hours per year due to regulation reserve shortages is appropriate for planning and ratemaking purposes. This is in addition to any loss of load resulting from transmission or distribution outages, resource adequacy, or other causes. The FRS applies this reliability target as follows:

- If the regulation reserve available is greater than the regulation reserve need for an hour, the LOLP is zero for that hour.
- If the regulation reserve held is less than the amount needed, the LOLP is derived from the Balancing Authority ACE Limit probability distribution as illustrated below.

**Balancing Authority ACE Limit: Allowed Deviations**

Even if insufficient regulation reserve capability is available to compensate for a thirty-minute sustained deviation, a violation of BAL-001-2 does not occur unless the deviation also exceeds the Balancing Authority ACE Limit.

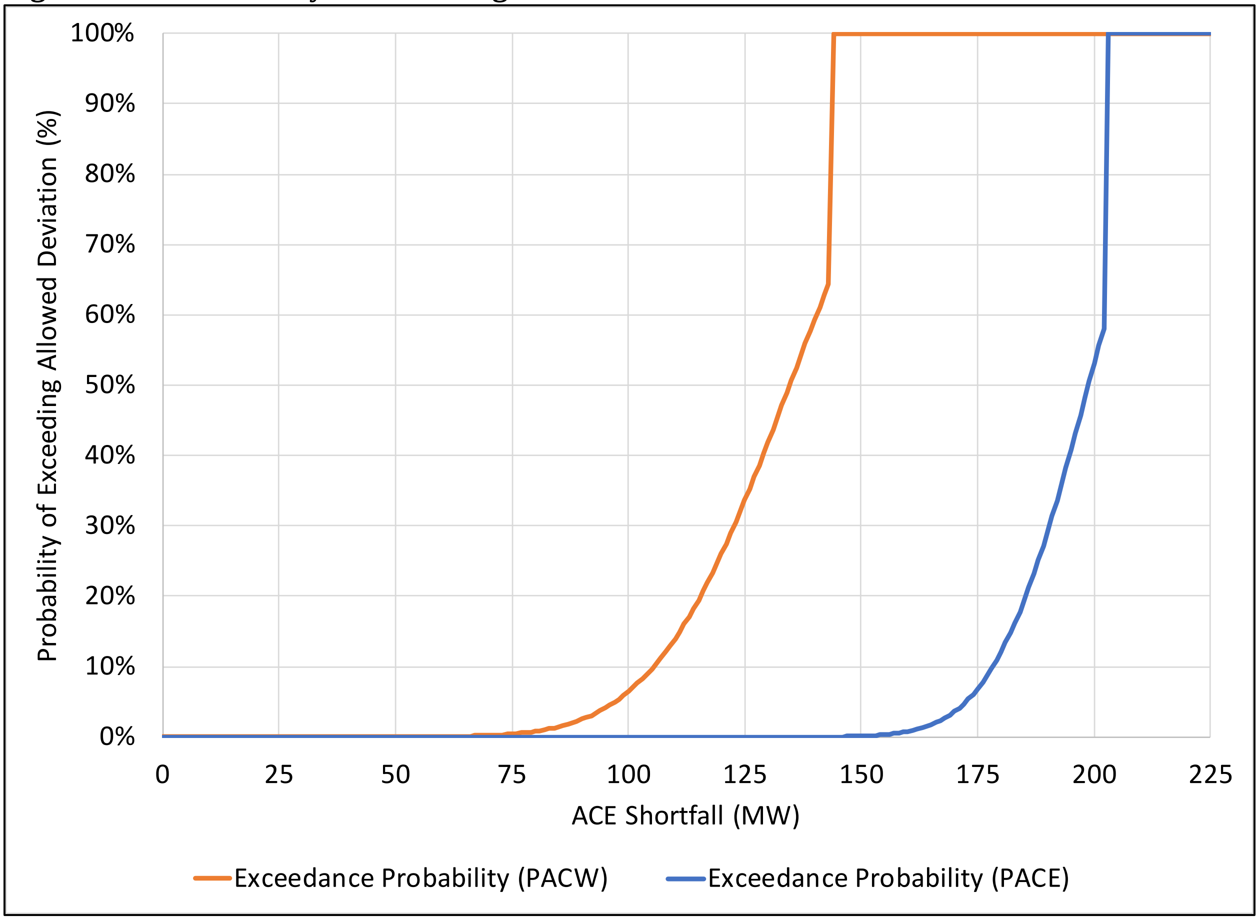
The Balancing Authority ACE Limit is specific to each BAA and is dynamic, varying as a function of interconnection frequency. When WECC frequency is close to 60 Hz, the Balancing Authority ACE Limit is large and large deviations in ACE are allowed. As WECC frequency drops further and further below 60 Hz, ACE deviations are increasingly restricted for BAAs that are contributing to the shortfall, i.e., those BAAs with higher loads than resources. A BAA commits a BAL-001-2 reliability violation if in any thirty-minute interval it does not have at least one minute when its ACE is within its Balancing Authority ACE Limit.

While the specific Balancing Authority ACE Limit for a given interval cannot be known in advance, the historical probability distribution of Balancing Authority ACE Limit values is known. Figure F.2 below shows the probability of exceeding the allowed deviation during a five-minute interval for a given level of ACE shortfall. For instance, an 82 MW ACE shortfall in PACW has a one percent chance of exceeding the Balancing Authority ACE Limit. WECC-wide frequency can change rapidly and without notice, and this causes large changes in the Balancing Authority ACE Limit over short time frames. Maintaining ACE within the Balancing Authority ACE Limit under those circumstances can require rapid deployment of large amounts of operating reserve. To limit the size and speed of resource deployment necessitated by variation in the Balancing Authority ACE Limit, PacifiCorp's operating practice caps permissible ACE at the lesser of the Balancing Authority ACE Limit or four times $L_{10}$. This also limits the occurrence of transmission flows that exceed path ratings as result of large variations in ACE.[20,21] This cap is reflected in Figure F.2.

[20] "Regional Industry Initiatives Assessment." NWPP MC Phase 3 Operations Integration Work Group. Dec. 31, 2014. Pg. 14. Available at: www.nwpp.org/documents/MC-Public/NWPP-MC-Phase-3-Regional-Industry-Initiatives-Assessment12-31-2014.pdf

[21] "NERC Reliability-Based Control Field Trial Draft Report." Western Electricity Coordinating Council. Mar. 25, 2015. Available at: www.wecc.biz/Reliability/RBC%20Field%20Trial%20Report%20Approved%203-25-2015.pdf

**Figure F.2 - Probability of Exceeding Allowed Deviation**




In 2018-2019, PacifiCorp's deviations and Balancing Authority ACE Limits were uncorrelated, which indicates that PacifiCorp's contribution to WECC-wide frequency is small. PacifiCorp's deviations and Balancing Authority ACE Limits were also uncorrelated when periods with large deviations were examined in isolation. If PacifiCorp's large deviations made distinguishable contributions to the Balancing Authority ACE Limit, ACE shortfalls would be more likely to exceed the Balancing Authority ACE Limit during large deviations. Since this is not the case, the probability of exceeding the Balancing Authority ACE Limit is lower, and less regulation reserve is necessary to comply with the BAL-001-2 standard.

**Regulation Reserve Forecast: Amount Held**

To calculate the amount of regulation reserve required to be held while being compliant with BAL-001-2 – using a LOLP of 0.5 hours per year or less – a quantile regression methodology was used. Quantile regression is a type of regression analysis. Whereas the typical method of ordinary least squares results in estimates of the conditional mean (50$^{th}$ percentile) of the response variable given certain values of the predictor variables, quantile regression aims at estimating other specified percentiles of the response variable. Eight regressions were prepared, one for each class (load/wind/solar/non-VER) and area (PACE/PACW). Each regression uses the following variables:

- Response Variable: the error in each interval, in megawatts.
- Predictor Variable: the forecasted generation or load in each interval, expressed as a percentage of area capacity.

The forecasted generation or load in each interval used as the predictor variable contributes to the regression as a combination of linear, square, and higher order exponential effects. Specifically, the regression identifies coefficients that correspond to the following functions for each class:

Load Error: Load $\text{Forecast}^1$ + Constant
Wind Error: Wind $\text{Forecast}^2$ + Wind $\text{Forecast}^1$
Solar Error: Solar $\text{Forecast}^4$ + Solar $\text{Forecast}^3$ + Solar $\text{Forecast}^2$ + Solar $\text{Forecast}^1$
Non-VER Error: Non-VER $\text{Forecast}^2$ + Non-VER $\text{Forecast}^1$

The instances requiring the largest amounts of regulation reserve occur infrequently, and many hours have very low requirements. If periods when requirements are likely to be low can be distinguished from periods when requirements are likely to be high, less regulation reserve is necessary to achieve a given reliability target. The regulation reserve forecast is not intended to compensate for every potential deviation. Instead, when a shortfall occurs, the size of that shortfall determines the probability of exceeding the Balancing Authority ACE Limit and a reliability violation occurring. The forecast is adjusted to achieve a cumulative LOLP that corresponds to the annual reliability target.

## Regulation Reserve Forecast

**Overview**

The following forecasts are polynomial functions that cover a targeted percentile of all historical deviations. These forecasts are stand-alone forecasts, based on the difference between hour-ahead base schedules and actual meter data, expressing the errors as a function of the level of forecast. The stand-alone reserve requirement shown achieves the annual reliability target of 0.5 hours per year, after accounting for the dynamic Balancing Authority ACE Limit. The combined diversity error system requirements are discussed later in the study. Figure F.3- Figure F.8 illustrate the relationship between the regulation reserve requirements during 2018-2019 and the forecasted level of output, for each resource class and control area. Both the regulation reserve requirements and the forecasted level of output are expressed as a percentage of resource nameplate (i.e., as a capacity factor). Figure F.9 and Figure F.10 illustrate the same relationship between the regulation reserve requirements during 2018-2019 and the forecasted load for each control area. Both the regulation reserve requirements and the forecasted load are expressed as a percentage of the annual peak load (i.e., as a load factor).

**Figure F.3 - Wind Regulation Reserve Requirements by Forecast - PACE**

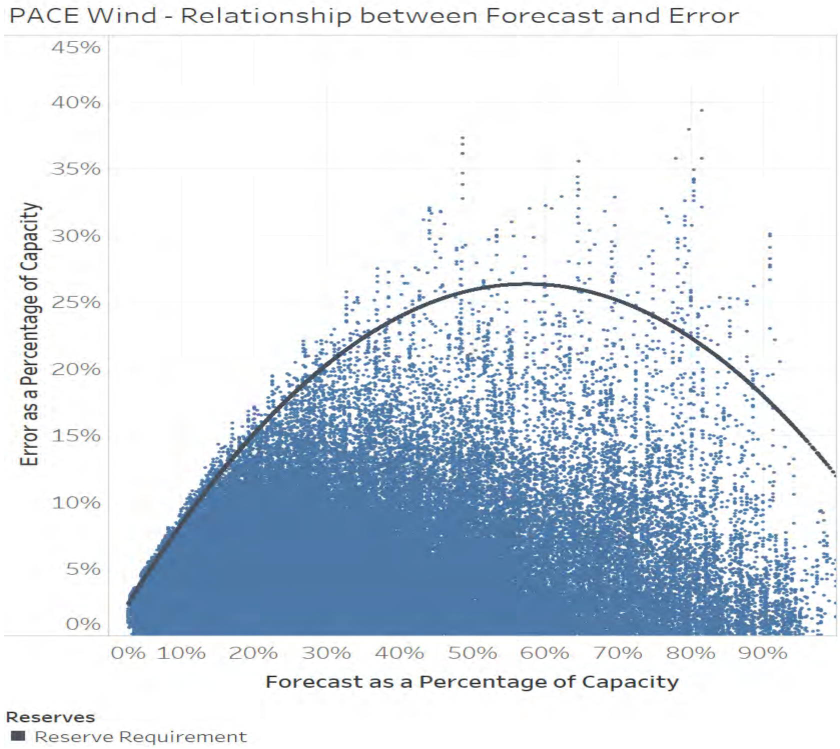



**Figure F.4 - Wind Regulation Reserve Requirements by Forecast Capacity Factor - PACW**

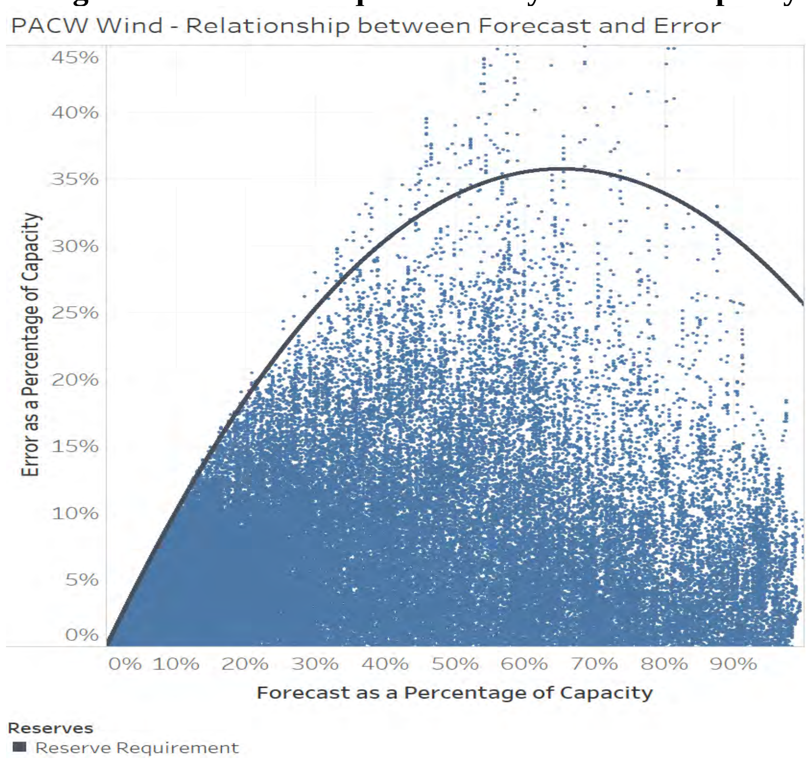


**Figure F.5 - Solar Regulation Reserve Requirements by Forecast Capacity Factor - PACE**

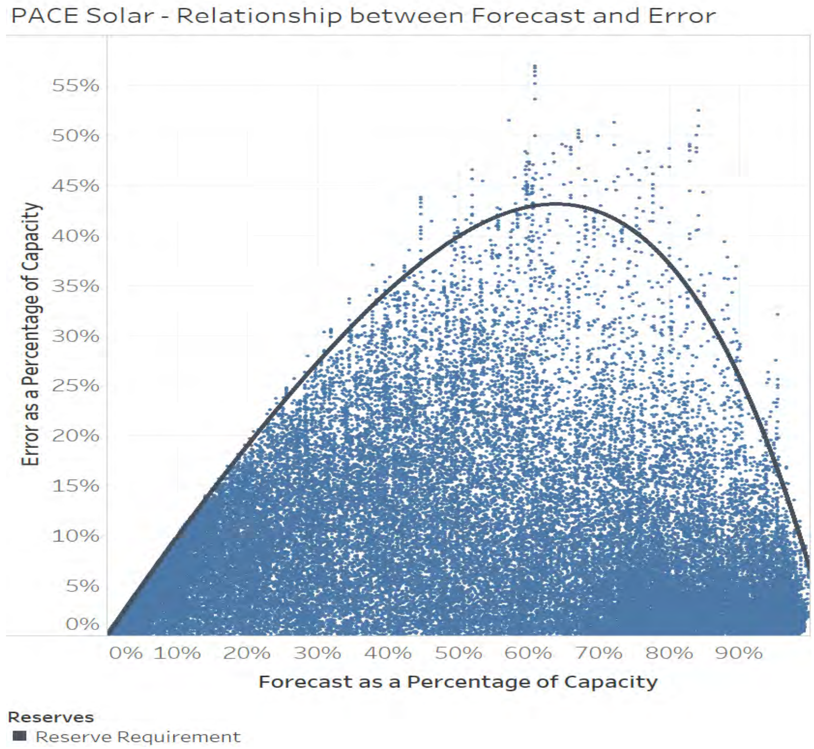



**Figure F.6 - Solar Regulation Reserve Requirements by Forecast Capacity Factor - PACW**

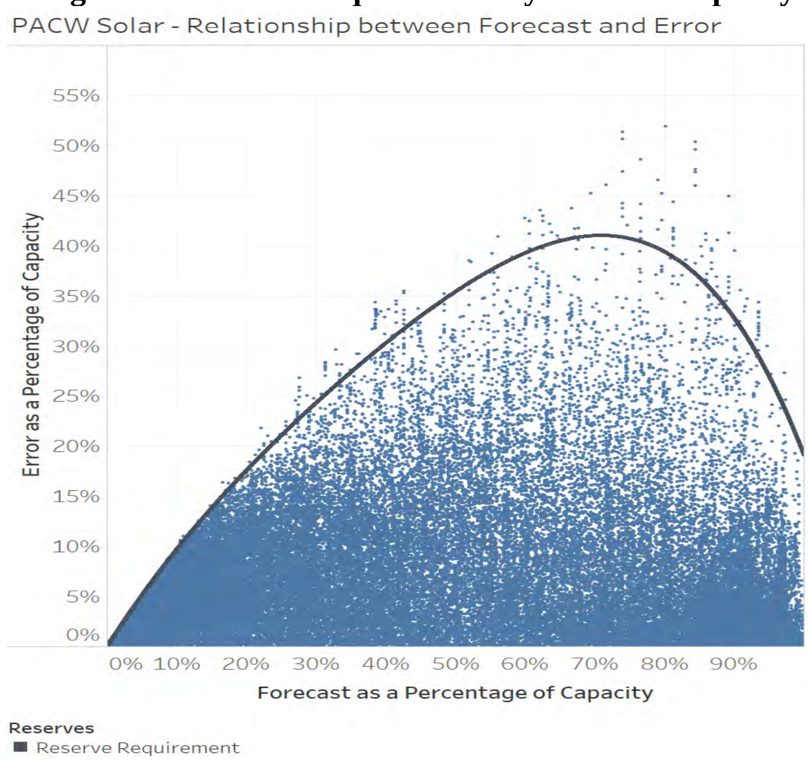


**Figure F.7 – Non-VER Regulation Reserve Requirements by Capacity Factor - PACE**

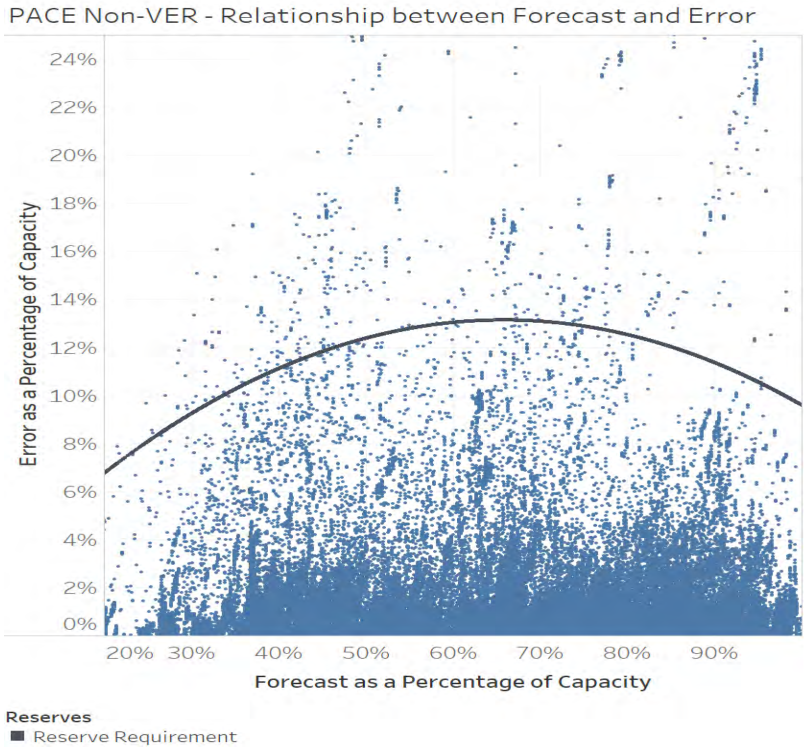



**Figure F.8 – Non-VER Regulation Reserve Requirements by Capacity Factor - PACW**

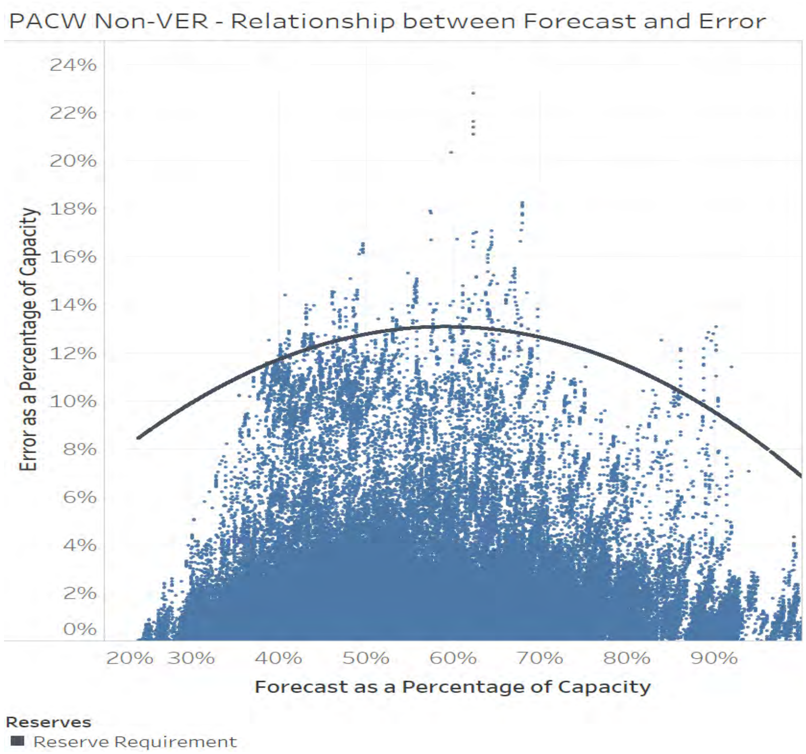


**Figure F.9 – Stand-alone Load Regulation Reserve Requirements - PACE**

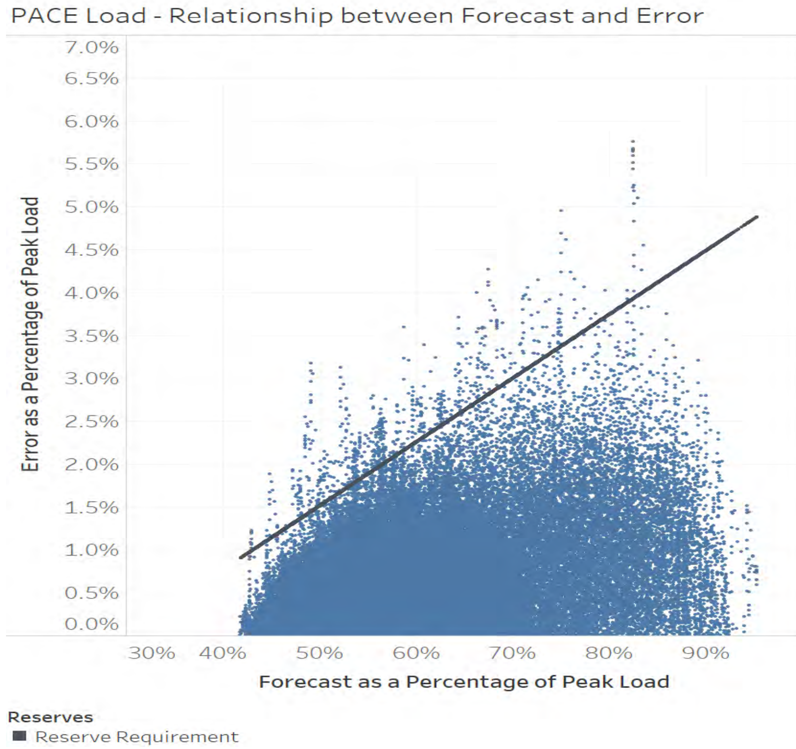
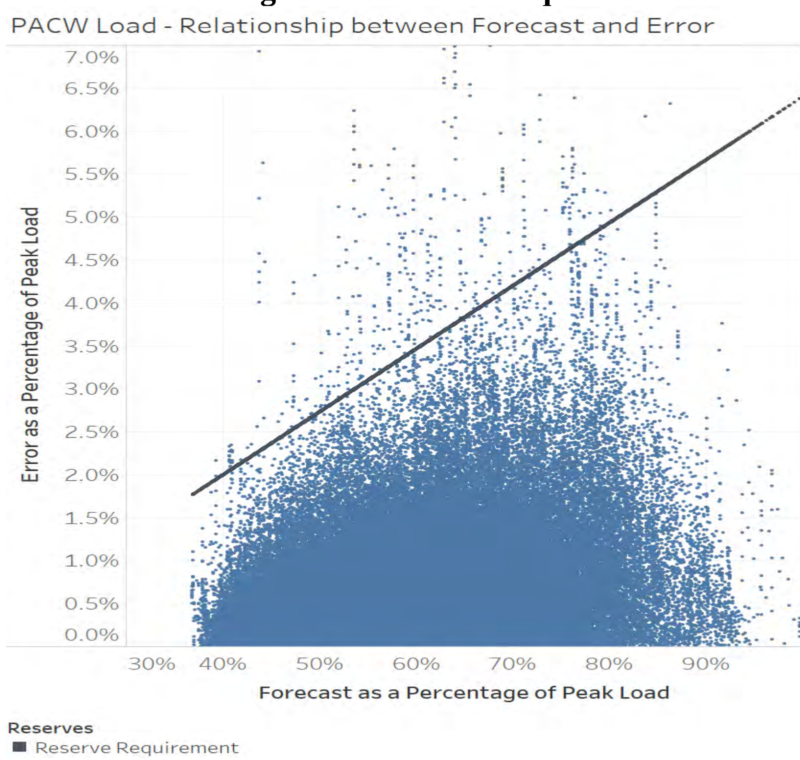



**Figure F.10 – Stand-alone Load Regulation Reserve Requirements - PACW**



The results of the analysis are shown in Table F.3 below.

**Table F.3 – Summary of Stand-alone Regulation Reserve Requirements**

| Scenario | Stand-alone Regulation Forecast (aMW) | Capacity (MW) | Stand-alone Regulation Forecast (%) |
|---|---|---|---|
| Non-VER | 106 | 1,304 | 8.2% |
| Load | 334 | 10,094 | 3.3% |
| VER - Wind | 457 | 2,745 | 16.7% |
| VER - Solar | 159 | 1,080 | 14.8% |
| **Total** | **1,057** | | |

## Portfolio Diversity and EIM Diversity Benefits

The EIM is a voluntary energy imbalance market service through the CAISO where market systems automatically balance supply and demand for electricity every fifteen and five minutes, dispatching least-cost resources every five minutes.

PacifiCorp and CAISO began full EIM operation on November 1, 2014. Many additional participants have since joined the EIM, such that it now includes nearly 80% of electricity demand in the Western interconnection, and more participants are scheduled to join in the next several years. PacifiCorp's participation in the EIM results in improved power production forecasting and optimized intra-hour resource dispatch. This brings important benefits including reduced energy dispatch costs through automatic dispatch, enhanced reliability with improved situational awareness, better integration of renewable energy resources, and reduced curtailment of renewable energy resources.

The EIM also has direct effects related to regulation reserve requirements. First, because of EIM participation, PacifiCorp has improved data used in the analysis contained in this FRS. The data and control provided by the EIM allow PacifiCorp to achieve the portfolio diversity benefits described in the first part of this section. Second, the EIM's intra-hour capabilities across the broader EIM footprint provide the opportunity to reduce the amount of regulation reserve necessary for PacifiCorp to hold, as further explained in the second part of this section.

### Portfolio Diversity Benefit

The regulation reserve forecasts described above independently ensure that the probability of a reliability violation for each class remains within the reliability target; however, the largest deviations in each class tend not to occur simultaneously, and in some cases, deviations will occur in offsetting directions. Because the deviations are not occurring at the same time, the regulation reserve held can cover the expected deviations for multiple classes at once and a reduced total quantity of reserve is sufficient to maintain the desired level of reliability. This reduction in the reserve requirement is the diversity benefit from holding a single pool of reserve to cover deviations in Solar, Wind, Non-VERs, and Load. As a result, the regulation reserve forecast for the portfolio can be reduced while still meeting the reliability target. In the historical period, portfolio diversity from the interactions between the various classes results in a regulation reserve requirement that is 36% lower than the sum of the stand-alone requirements, or approximately 679 MW.

## EIM Diversity Benefit

In addition to the direct benefits from EIM's increased system visibility and improved intra-hour operational performance described above, the participation of other entities in the broader EIM footprint provides the opportunity to further reduce the amount of regulation reserve PacifiCorp must hold.

By pooling variability in load and resource output, EIM entities reduce the quantity of reserve required to meet flexibility needs. The EIM also facilitates procurement of flexible ramping capacity in the fifteen-minute market to address variability that may occur in the five-minute market. Because variability across different BAAs may happen in opposite directions, the flexible ramping requirement for the entire EIM footprint can be less than the sum of individual BAA requirements. This difference is known as the "diversity benefit" in the EIM. This diversity benefit reflects offsetting variability and lower combined uncertainty. This flexibility reserve (uncertainty requirement) is in addition to the spinning and supplemental reserve carried against generation or transmission system contingencies under the NERC standards.

The CAISO calculates the EIM diversity benefit by first calculating an uncertainty requirement for each individual EIM BAA and then by comparing the sum of those requirements to the uncertainty requirement for the entire EIM area. The latter amount is expected to be less than the sum of the uncertainty requirements from the individual BAAs due to the portfolio diversification effect of forecasting a larger pool of load and resources using intra-hour scheduling and increased system visibility in the hypothetical, single-BAA EIM. Each EIM BAA is then credited with a share of the diversity benefit calculated by CAISO based on its share of the stand-alone requirement relative to the total stand-alone requirement.

The EIM does not relieve participants of their reliability responsibilities. EIM entities are required to have sufficient resources to serve their load on a standalone basis each hour before participating in the EIM. Thus, each EIM participant remains responsible for all reliability obligations. Despite these limitations, EIM imports from other participating BAAs can help balance PacifiCorp's loads and resources within an hour, reducing the size of reserve shortfalls and the likelihood of a Balancing Authority ACE Limit violation. While substantial EIM imports do occur in some hours, it is only appropriate to rely on PacifiCorp's diversity benefit associated with EIM participation, as these are derived from the structure of the EIM rather than resources contributed by other participants.

Table F.4 below provides a numeric example of uncertainty requirements and application of the calculated diversity benefit.

**Table F.4 – EIM Diversity Benefit Application Example**

| | a | b | c | d | e =a+b+c+d | f | g = e-f | h = g / e | i = c * h | j = c - i |
|---|---|---|---|---|---|---|---|---|---|---|
| Hour | CAISO req't. before benefit (MW) | NEVP req't. before benefit (MW) | PACE req't. before benefit (MW) | PACW req't. before benefit (MW) | Total req't. before benefit (MW) | Total req't. after benefit (MW) | Total diversity benefit (MW) | Diversity benefit ratio (MW) | PACE benefit (MW) | PACE req't. after benefit (MW) |
| 1 | 550 | 110 | 165 | 100 | 925 | 583 | 342 | 37.00% | 61 | 104 |
| 2 | 600 | 110 | 165 | 100 | 975 | 636 | 339 | 34.80% | 57 | 108 |
| 3 | 650 | 110 | 165 | 110 | 1,035 | 689 | 346 | 33.40% | 55 | 110 |
| 4 | 667 | 120 | 180 | 113 | 1,080 | 742 | 338 | 31.30% | 56 | 124 |

While the diversity benefit is uncertain, that uncertainty is not significantly different from the uncertainty in the Balancing Authority ACE Limit previously described. In the FRS, PacifiCorp has credited the regulation reserve forecast based on a historical distribution of calculated EIM diversity benefits. While this FRS considers regulation reserve requirements in 2018-2019, the CAISO identified an error in their calculation of uncertainty requirements in early 2018. CAISO's published uncertainty requirements and associated diversity benefits are now only valid for March 2018 forward. To capture these additional benefits for this analysis, PacifiCorp has applied the historical distribution of EIM diversity benefits from the 12 months beginning March 2018. In the historical study period, EIM diversity benefits used in the FRS would have reduced regulation reserve requirements by approximately 140 MW.

The inclusion of EIM diversity benefits in the FRS reduces the magnitude, and thus probability, of reserve shortfalls and, in doing so, reduces the overall regulation reserve requirement. This allows PacifiCorp's forecasted requirements to be reduced. As shown in Table F.5 below, the resulting regulation reserve requirement is 540 MW, which is a 49 percent reduction (including the portfolio diversity benefit) compared to the stand-alone requirement for each class. This portfolio regulation forecast is expected to achieve an LOLP of 0.5 hours per year.

**Table F.5 – 2018-2019 Results with Portfolio Diversity and EIM Diversity Benefits**

| Scenario | Stand-alone Regulation Forecast (aMW) | Stand-alone Rate (%) | Portfolio Regulation Forecast w/EIM (aMW) | Portfolio Rate (%) | Capacity (MW) | Rate Determinant |
|---|---|---|---|---|---|---|
| Non-VER | 106 | 8.2% | 55 | 4.2% | 1,304 | Nameplate |
| Load | 334 | 3.3% | 172 | 1.7% | 10,094 | 12 CP |
| VER - Wind | 457 | 16.7% | 237 | 8.6% | 2,745 | Nameplate |
| VER - Solar | 159 | 14.8% | 76 | 7.1% | 1,080 | Nameplate |
| **Total** | **1,057** | | **540** | | | |

## Fast-Ramping Reserve Requirements

As previously discussed, Requirement 1 of BAL-001-2 specifies that PacifiCorp's CPS1 score must be greater than equal to 100 percent for each preceding 12 consecutive calendar month period, evaluated monthly. The CPS1 score compares PacifiCorp's ACE with interconnection frequency during each clock minute. A higher score indicates PacifiCorp's ACE is helping interconnection frequency, while a lower score indicates it is hurting interconnection frequency. Because CPS1 is averaged and evaluated on a monthly basis, it does not require a response to each and every ACE event but rather requires that PacifiCorp meet a minimum aggregate level of performance in each month.

The Regulation Reserve Forecast described above is evaluating requirements for extreme deviations that are at least 30 minutes in duration, for compliance with Requirement 2 of BAL-001-2. In contrast, compliance with CPS1 requires reserve capability to compensate for most conditions over a minute-to-minute basis. These fast-ramping resources would be deployed frequently and would also contribute to compliance with Requirement 2 of BAL-001-2, so they are a subset of the Regulation Reserve Forecast described above.

To evaluate CPS1 requirements, PacifiCorp compared the net load change for each five-minute interval in the study period to the corresponding value for Requirement 2 compliance in that hour from the Regulation Reserve Forecast, after accounting for diversity (resulting in a 540 MW average requirement). Resources may deploy for Requirement 2 compliance over up to 30 minutes, so the average requirement of 540 MW would require ramping capability of at least 18.0 MW per minute (540 MW / 30 minutes).

Because CPS1 is averaged and evaluated monthly, it does not require a response to each and every ACE event but rather requires that PacifiCorp meet a minimum aggregate level of performance in each month. Resources capable of ensuring compliance in 95 percent of intervals are expected to be sufficient to meet CPS1 and given that ACE may deviate in either a positive or negative direction, the 97.5$^{th}$ percentile of incremental requirements versus Requirement 2 in that interval was evaluated. At the 97.5$^{th}$ percentile, fast ramping requirements for PACE and PACW are 1.7 MW/minute and 0.8 MW/minute higher than the Requirement 2 ramp rate, respectively; however, if dynamic transfers between the BAAs are available, the 97.5$^{th}$ percentile for system is 0.6 MW / minute lower than the Requirement 2 value. When viewed on a system basis, this means that 30-minute ramping capability held for Requirement 2 would be sufficient to cover an adequate portion of the fast-ramping events to ensure CPS1 compliance.

Note that resources must respond immediately to ensure compliance with Requirement 1, as performance is measured on a minute-to-minute basis. As a result, resources that respond after a delay, such as quick-start gas plants or certain interruptible loads, would not be suitable for Requirement 1 compliance, so these resources cannot be allocated the entire regulation reserve requirement. However, because Requirement 1 compliance is a small portion of the total regulation reserve requirement, these restrictions on resource type are unlikely to be a meaningful constraint.

In addition, CPS1 compliance is weighted toward performance during conditions when interconnection frequency deviations are large. The largest frequency deviations would also result in deployment of frequency response reserves, which are somewhat larger in magnitude, though they have a less stringent performance metric under BAL-003-2, based on median response during the largest events.

In light of the overlaps with BAL-001-2 Requirement 2 and BAL-003-2 described above, CPS1 compliance is not expected to result in an additional requirement beyond what is necessary to comply with those standards.

## Portfolio Regulation Reserve Requirements

The IRP portfolio optimization process contemplates the addition of new wind and solar capacity as part of its selection of future resources, as well as changes in peak load due to load growth and energy efficiency measure selection. These load and resource changes are expected to drive changes in PacifiCorp's regulation reserve requirements that will vary from portfolio to portfolio.

The locations that have been identified as likely sites for future wind and solar additions are in relatively close proximity to existing wind and solar resources, and PacifiCorp's portfolio of resources is already relatively diverse with significant wind in Wyoming, along the Columbia River gorge, and in eastern Idaho/western Wyoming and significant solar in southern Utah and southern Oregon. Because future resources are likely to be added in relatively close proximity to these existing resources, they are not likely to change the diversity for that class of resources as a whole. Given the sizeable sample of existing wind and solar resources in PACE and PACW, maintaining the existing level of diversity as a class of resources doubles or quadruples is a more likely outcome than the continuing improvements previously assumed in the 2019 FRS. With that in mind, the incremental regulation reserve analysis for the 2021 FRS methodology assumes that wind, solar, and load deviations scale linearly with capacity increases from the actual data in the 2018-2019 historical period.

While diversity within each class is not expected to change significantly, there is the opportunity for greater diversity among the wind, solar, and load requirements. These portfolio-related benefits are inherently tied to the portfolio, so it is appropriate that they vary with the portfolio. To that end, the 2021 FRS methodology calculates the portfolio diversity benefits specific to a wide variety of wind and solar capacity combinations, rather than relying upon the historical portfolio diversity value.

As part of the portfolio diversity calculation, the analysis assumes that minimum EIM flexible reserve requirements and EIM diversity benefits scale with changes in portfolio capacity. EIM minimum flexible reserve requirements are tied to the uncertainty in PacifiCorp's requirements, which grow with changes portfolio capacity, so it would be impacted directly. EIM diversity benefits reflect PacifiCorp's share of stand-alone requirements relative to those of the rest of the BAA's participating in EIM. All else being equal, increases in PacifiCorp's portfolio capacity would result in a greater proportion of the EIM diversity benefits being allocated to PacifiCorp.

Portfolio diversity is driven by interplay among the deviations by wind, solar, and load, so it is not a single number, but rather is dependent on the specific conditions. The 2021 FRS methodology incorporates two mechanisms to better account for these interactions. First, a portfolio diversity value is calculated specific to each hour of the day in each season. Second, rather than applying an equal percentage reduction to all hours, diversity benefits are assumed to be highest when stand-alone requirements are highest. For example, there is more opportunity for offsetting requirements when load, wind, and solar all have significant stand-alone requirements. With that in mind, diversity is applied as an exponent to the incremental requirement more than the EIM minimum requirement. The result of this calculation is a diversity benefit which is highest for large reserve requirements, and which approaches zero as the requirement approaches the EIM minimum, as illustrated in Table F.6.

**Table F.6 – Portfolio Diversity Exponent Example**

| | | | Incremental Requirement w/ Diversity (MW) By Diversity Exponent | | | Portfolio Diversity (%) By Diversity Exponent | | |
|---|---|---|---|---|---|---|---|---|
| Stand-alone Reserve Req. (MW) | EIM Floor (MW) | Stand-alone Incremental Req. (MW) | d = c ^ 75% | e = c ^ 85% | f = c ^ 95% | g = 1 - (b + d)/a | h = 1 - (b + e)/a | i = 1 - (b + f)/a |
| a | b | c = a - b | 75% | 85% | 95% | 75% | 85% | 95% |
| 200 | 200 | 0 | 0 | 0 | 0 | 0% | 0% | 0% |
| 250 | 200 | 50 | 19 | 28 | 41 | 12% | 9% | 4% |
| 300 | 200 | 100 | 32 | 50 | 79 | 23% | 17% | 7% |
| 350 | 200 | 150 | 43 | 71 | 117 | 31% | 23% | 9% |
| 400 | 200 | 200 | 53 | 90 | 153 | 37% | 27% | 12% |
| 450 | 200 | 250 | 63 | 109 | 190 | 42% | 31% | 13% |
| 500 | 200 | 300 | 72 | 128 | 226 | 46% | 34% | 15% |

For each combination of wind and solar capacity, the hourly portfolio diversity exponents for each season are increased in a stepwise fashion until the risk of regulation reserve shortfalls during an interval is sufficiently low and the overall risk of regulation reserve shortfalls achieves the target of 0.5 hours per year. The resulting portfolio diversity is maximized for a combination of wind and solar as summarized in Table F.77 and Table F.8 for PacifiCorp East and PacifiCorp West, respectively.

**Table F.7 – PacifiCorp East Diversity by Portfolio Composition**

(% Reduction vs. Stand-alone Requirements)

| East Wind Capacity MW | % | 50% | 100% | 166% | 329% | 493% | 656% | 820% | 983% |
|---|---|---|---|---|---|---|---|---|---|
| | | 428 | 855 | 1,462 | 2,502 | 3,542 | 4,582 | 5,622 | 6,662 |
| 8,224 | 548% | 17.2% | 18.8% | 20.6% | | | | | |
| 7,184 | 472% | 19.2% | 21.5% | 23.0% | 25.5% | 26.5% | | | |
| 6,144 | 395% | 22.9% | 24.1% | 25.6% | 27.9% | 28.5% | 29.0% | | |
| 5,104 | 319% | 26.0% | 27.3% | 29.2% | 30.7% | 30.7% | 30.5% | 29.5% | |
| 4,064 | 242% | 30.4% | 31.6% | 32.9% | 33.8% | 32.7% | 32.8% | 32.8% | |
| 3,024 | 166% | 35.0% | 36.2% | 38.5% | 37.1% | 37.6% | 36.2% | 33.9% | 31.9% |
| 1,575 | 100% | | $\boxed{48.0\%}$ | 45.8% | 43.1% | 39.5% | 35.8% | 32.2% | 29.4% |
| 788 | 50% | | | 46.4% | 40.3% | 36.4% | 33.0% | 30.0% | 27.3% |

East Solar Capacity (% / MW)

▭ 2018-2019 Actual Wind and Solar Capacity

**Table F.8 – PacifiCorp West Diversity by Portfolio Composition**

(% Reduction vs. Stand-alone Requirements)

| West Wind Capacity MW | % | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 4,389 | 548% | 21.1% | 22.4% | 22.9% | | | | | |
| 3,669 | 472% | 23.4% | 24.8% | 25.4% | 29.0% | 33.0% | | | |
| 2,949 | 395% | 26.2% | 26.7% | 27.6% | 32.1% | 34.8% | 38.1% | | |
| 2,229 | 319% | 29.6% | 30.6% | 31.4% | 36.2% | 39.5% | 42.7% | 42.7% | |
| 1,509 | 242% | 33.8% | 34.5% | 36.3% | 40.8% | 45.2% | 46.2% | 43.9% | |
| 789 | 166% | 38.8% | 41.6% | 43.1% | 47.6% | 48.4% | 47.7% | 45.0% | 44.3% |
| 726 | 100% | | $\boxed{42.4\%}$ | 42.9% | 48.6% | 49.3% | 47.7% | 46.2% | 44.4% |
| 363 | 50% | | | 41.7% | 47.1% | 49.8% | 47.4% | 45.0% | 43.2% |
| | % | 50% | 100% | 166% | 329% | 493% | 656% | 820% | 983% |
| | MW | 111 | 221 | 321 | 1,041 | 1,761 | 2,481 | 3,201 | 3,921 |

**West Solar Capacity**

2018-2019 Actual Wind and Solar Capacity

After portfolio selection is complete, regulation reserve requirements are calculated specific to a portfolio's load, wind, and solar resources in each year. The hourly regulation reserve requirement varies as a function of annual peak load net of energy efficiency selections as well as total wind and solar capacity. The regulation reserve requirement also varies based on the hourly load net of energy efficiency and hourly wind and solar generation values. Diversity exponents specific to the wind and solar capacity in each year are applied by hour and season, by interpolating among the scenarios illustrated in Figure F.7 and Figure F.8. For example, the diversity exponent for hour five in the spring for a PACW study with 1,000 MW of wind and 1,000 MW of solar would reflect a weighting of diversity exponents in hour five in the spring from four scenarios. The highest weighting would apply to the 789 MW wind/1,041 MW solar scenario, and successively lower weightings would apply to 1,509 MW wind/1,041 MW solar, 789 MW wind/321 MW solar, and 1,509 MW wind/321 MW solar, with the total weighting for all four scenarios summing to 100%.

Finally, an adjustment is made to account for the ability of resources that are combined with storage to offset their own generation shortfalls beyond what is already captured by the model. For example, combined solar and storage resources can offset their own generation shortfalls, up to their interconnection limit. In actual operation, a reduction in solar generation would enable additional storage discharge. However, within the PLEXOS model, there are no intra-hour variations in load or renewable resource output and thus no potential increase in storage discharge. Note that combined storage can only be discharged when there is a generation shortfall at the adjacent resource, so it cannot cover all shortfalls across the system. For example, many solar resources do not have co-located storage, and their errors would continue to need to be met with incremental reserves. Nonetheless, combined solar and storage can cover a portion of their own shortfalls, and that portion increases as more combined storage resources are added to the system. This adjustment reduces the hourly regulation reserve requirement that is entered in the model.

## Regulation Reserve Cost

The PLEXOS model reports marginal reserve prices on an hourly basis. So long as the change in reserve obligations or capability from what was input for a study is relatively small, this reserve price can provide a reasonable estimate of the impact of changes in reserves, without requiring additional model runs.

To estimate wind and solar integration costs for the 2025 IRP, PacifiCorp prepared a PLEXOS scenario that reflected the final regulation reserve requirements, consistent with the Company's existing wind and resources plus selections in the preferred portfolio. Hourly regulation reserve prices were reported from this study.

**Wind Integration**

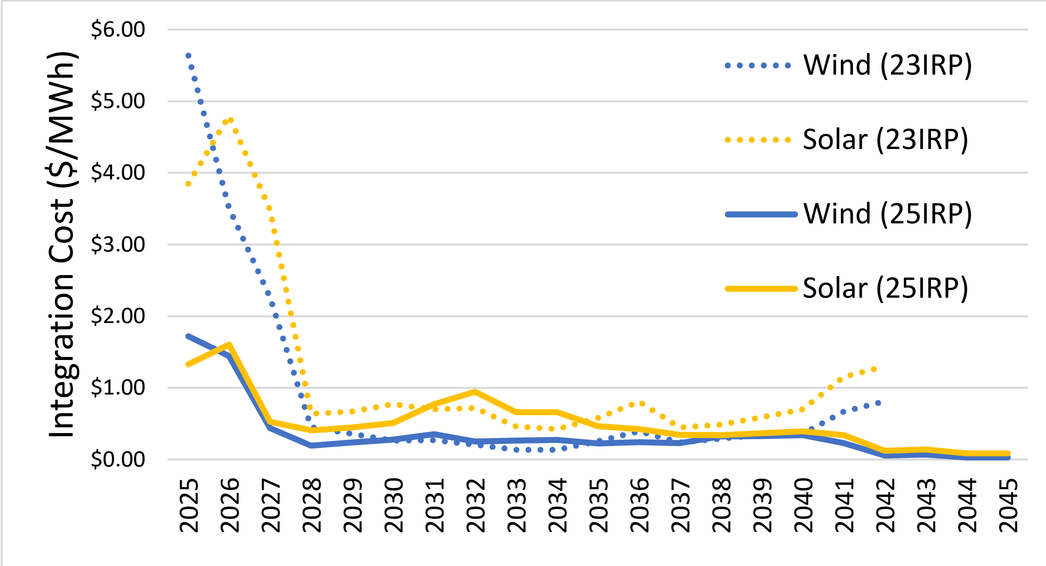
The wind reserve case uses the 2021 FRS methodology to recalculate the wind reserve requirement for a portfolio with 5 MW more wind resources in each year of the IRP study horizon (2025-2045). The change in resources applies to both PACE and PACW and is allocated pro-rata among all wind resources in the area, such that the aggregate hourly capacity factor is not impacted by the change in capacity. The change in wind capacity results in incremental regulation reserve requirements that average approximately 15% of the nameplate capacity of the wind. Wind integration costs are calculated by multiplying the hourly change in reserve requirements (in MW) by the hourly regulation reserve price in each hour of the year and then dividing that total by the incremental wind generation over the year.

**Solar Integration**

The solar reserve case uses the 2021 FRS methodology to recalculate the solar reserve requirement for a portfolio with 5 MW more solar resources in each year of the IRP study horizon (2025-2045). The change in resources applies to both PACE and PACW and is allocated pro-rata among all solar resources in the area, such that the aggregate hourly capacity factor is not impacted by the change in capacity. The change in solar capacity results in incremental regulation reserve requirements that average approximately 7% of the nameplate capacity of the solar. Solar integration costs are calculated by multiplying the hourly change in reserve requirements (in MW) by the hourly regulation reserve price in each hour of the year and then dividing that total by the incremental solar generation over the year.

The incremental regulation reserve cost results for wind and solar are shown in Figure F.11. The comparable regulation reserve costs from the 2023 IRP are also shown. Integration costs in the 2023 IRP were elevated in the near term as a result of compliance with the Ozone Transport Rule. In the absence of those requirements, integration costs in the 2025 IRP are reduced in the near term. Integration costs fall as energy storage resources are added to the portfolio, as they can provide operating reserves at no additional cost while charging and in any hour in which they are not discharging and not fully depleted, which for a four-hour energy storage resource is most of the day.

**Figure F.11 – Incremental Wind and Solar Regulation Reserve Costs**




# Flexible Resource Needs Assessment

## Overview

In its Order No. 12-013 issued on January 19, 2012, in Docket No. UM 1461 on "Investigation of matters related to Electric Vehicle Charging", the Oregon Public Utility Commission (OPUC) adopted the OPUC staff's proposed IRP guideline:

1. Forecast the Demand for Flexible Capacity: The electric utilities shall forecast the balancing reserves needed at different time intervals (e.g., ramping needed within 5 minutes) to respond to variation in load and intermittent renewable generation over the 20-year planning period.

2. Forecast the Supply of Flexible Capacity: The electric utilities shall forecast the balancing reserves available at different time intervals (e.g., ramping available within 5 minutes) from existing generating resources over the 20-year planning period.

3. Evaluate Flexible Resources on a Consistent and Comparable Basis: In planning to fill any gap between the demand and supply of flexible capacity, the electric utilities shall evaluate all resource options including the use of electric vehicles (EVs), on a consistent and comparable basis.

In this section, PacifiCorp first identifies its flexible resource needs for the IRP study period of 2025 through 2045, and the calculation method used to estimate those requirements. PacifiCorp then identifies its supply of flexible capacity from its generation resources, in accordance with the Western Electricity Coordinating Council (WECC) operating reserve guidelines, demonstrating that PacifiCorp has sufficient flexible resources to meet its requirements.

## Forecasted Reserve Requirements

Since contingency reserve and regulation reserve are separate and distinct components, PacifiCorp estimates the forward requirements for each separately. The contingency reserve requirements are derived from the PLEXOS model. The regulating reserve requirements are part of the inputs to the PLEXOS model and are calculated by applying the methods developed in the Portfolio Regulation Reserve Requirements section. The contingency and regulation reserve requirements are two distinct components that are modeled separately in the 2025 IRP: 10-minute contingency reserve requirements and 30-minute regulation reserve requirements. The average reserve requirements for PacifiCorp's two balancing authority areas are shown in Table F.9 below.

**Table F.9 - Reserve Requirements (Average MW)**

| Year | East Requirement | | | West Requirement | | |
|---|---|---|---|---|---|---|
| | Spin (10-minute) | Non-spin (10-minute) | Regulation (30-minute) | Spin (10-minute) | Non-spin (10-minute) | Regulation (30-minute) |
| 2025 | 160 | 160 | 491 | 84 | 84 | 106 |
| 2026 | 158 | 158 | 548 | 85 | 85 | 106 |
| 2027 | 161 | 161 | 555 | 86 | 86 | 106 |
| 2028 | 163 | 163 | 569 | 88 | 88 | 292 |
| 2029 | 166 | 166 | 576 | 89 | 89 | 188 |
| 2030 | 169 | 169 | 576 | 90 | 90 | 359 |
| 2031 | 172 | 172 | 626 | 91 | 91 | 362 |
| 2032 | 173 | 173 | 624 | 91 | 91 | 370 |
| 2033 | 177 | 177 | 621 | 93 | 93 | 387 |
| 2034 | 180 | 180 | 620 | 94 | 94 | 397 |
| 2035 | 183 | 183 | 621 | 95 | 95 | 424 |
| 2036 | 186 | 186 | 618 | 96 | 96 | 451 |
| 2037 | 190 | 190 | 615 | 98 | 98 | 476 |
| 2038 | 194 | 194 | 609 | 100 | 100 | 493 |
| 2039 | 198 | 198 | 607 | 102 | 102 | 535 |
| 2040 | 201 | 201 | 602 | 104 | 104 | 569 |
| 2041 | 206 | 206 | 583 | 106 | 106 | 577 |
| 2042 | 210 | 210 | 592 | 108 | 108 | 579 |
| 2043 | 213 | 213 | 591 | 110 | 110 | 577 |
| 2044 | 216 | 216 | 580 | 112 | 112 | 591 |
| 2045 | 221 | 221 | 587 | 114 | 114 | 612 |

## Flexible Resource Supply Forecast

Requirements by NERC and the WECC dictate the types of resources that can be used to serve the reserve requirements.

- **10-minute spinning reserve** can only be provided by resources currently online and synchronized to the transmission grid.

- **10-minute non-spinning reserve** may be served by fast-start resources that are capable of being online and synchronized to the transmission grid within ten minutes. Interruptible load can only provide non-spinning reserve. Non-spinning reserve may be provided by resources that are capable of providing spinning reserve.

- **30-minute regulation reserve** can be provided by unused spinning or non-spinning reserve. Incremental 30-minute ramping capability beyond the 10-minute capability captured in the categories above also counts toward this requirement.

The resources that PacifiCorp employs to serve its reserve requirements include owned hydro resources that have storage, owned thermal resources, and purchased power contracts that provide reserve capability.

Hydro resources are generally deployed first to meet the spinning reserve requirements because of their flexibility and their ability to respond quickly. The amount of reserve that these resources can provide depends upon the difference between their expected capacities and their generation level at the time. The hydro resources that PacifiCorp may use to cover reserve requirements in the PacifiCorp West balancing authority area include its facilities on the Lewis River and the Klamath River as well as its share of generation and capacity from the Mid-Columbia projects. In the PacifiCorp East balancing authority area, PacifiCorp may use facilities on the Bear River to provide spinning reserve.

Thermal resources are also used to meet the spinning reserve requirements when they are online. The amount of reserve provided by these resources is determined by their ability to ramp up within a 10-minute interval. For natural gas-fired combustion turbines, the amount of reserve can be close to the differences between their nameplate capacities and their minimum generation levels. In contrast, both coal and gas-converted steam turbines have slower ramp rates and may ramp from minimum to maximum over an hour or more. In the current IRP, PacifiCorp's reserve needs are increasingly met by energy storage resources, including contracted resources and proxy resource selections in the preferred portfolio.

Table F.10 lists the annual reserve capability from resources in PacifiCorp's East and West balancing authority areas.[22] The changes in the flexible resource supply reflect retirement of existing resources, addition of new preferred portfolio resources, and variation in hydro capability due to forecasted streamflow conditions, and expiration of contracts from the Mid-Columbia projects that are reflected in the preferred portfolio.

[22] Frequency response capability is a subset of the 10-minute capability shown. Battery resources are capable of responding with their maximum output during a frequency event and can provide an even greater response if they were charging at the start of an event. PacifiCorp has sufficient frequency response capability at present and by 2026 the battery capacity currently contracted or added in the preferred portfolio will exceed PacifiCorp's current 266.4 MW frequency response obligation for a 0.3 Hz event. As a result, compliance with the frequency response obligation is not anticipated to require incremental supply.

**Table F.10 - Flexible Resource Supply Forecast (Average MW)**

| Year | East Supply (10-Minute) | West Supply (10-Minute) | East Supply (30-Minute) | West Supply (30-Minute) |
|---|---|---|---|---|
| 2025 | 1,816 | 942 | 2,507 | 1,016 |
| 2026 | 2,925 | 942 | 3,629 | 1,016 |
| 2027 | 2,924 | 942 | 3,628 | 1,016 |
| 2028 | 2,920 | 2,113 | 3,602 | 2,188 |
| 2029 | 2,971 | 2,362 | 3,661 | 2,437 |
| 2030 | 3,065 | 3,174 | 3,755 | 3,249 |
| 2031 | 3,136 | 3,265 | 3,826 | 3,340 |
| 2032 | 3,313 | 3,390 | 4,003 | 3,465 |
| 2033 | 3,327 | 3,433 | 4,017 | 3,508 |
| 2034 | 3,325 | 3,650 | 4,015 | 3,725 |
| 2035 | 3,327 | 3,676 | 4,017 | 3,751 |
| 2036 | 3,308 | 3,750 | 3,998 | 3,825 |
| 2037 | 3,425 | 3,761 | 4,116 | 3,835 |
| 2038 | 3,425 | 4,025 | 4,116 | 4,100 |
| 2039 | 3,432 | 4,132 | 4,122 | 4,207 |
| 2040 | 3,029 | 5,097 | 3,705 | 5,246 |
| 2041 | 3,077 | 5,274 | 3,753 | 5,423 |
| 2042 | 3,977 | 5,489 | 4,654 | 5,638 |
| 2043 | 3,947 | 5,902 | 4,567 | 6,051 |
| 2044 | 4,449 | 6,099 | 5,069 | 6,248 |
| 2045 | 5,165 | 6,464 | 5,785 | 6,613 |

Figure F.12 and Figure F.13 graphically display the balances of reserve requirements and capability of spinning reserve resources in PacifiCorp's East and West balancing authority areas respectively. The graphs demonstrate that PacifiCorp's system has sufficient resources to serve its reserve requirements throughout the IRP planning period. Note that keeping minimum amounts in energy storage or bringing thermal plants online and/or reducing their generation while online are required to achieve the reserve capability shown in the figures. In addition, PacifiCorp currently can transfer a portion of the operating reserves held in either of its balancing authority areas to help meet the requirements of its other balancing authority area, based on the reserve need and relative economics of the available supply.

**Figure F.12 - Comparison of Reserve Requirements and Resources, East Balancing Authority Area (MW)**

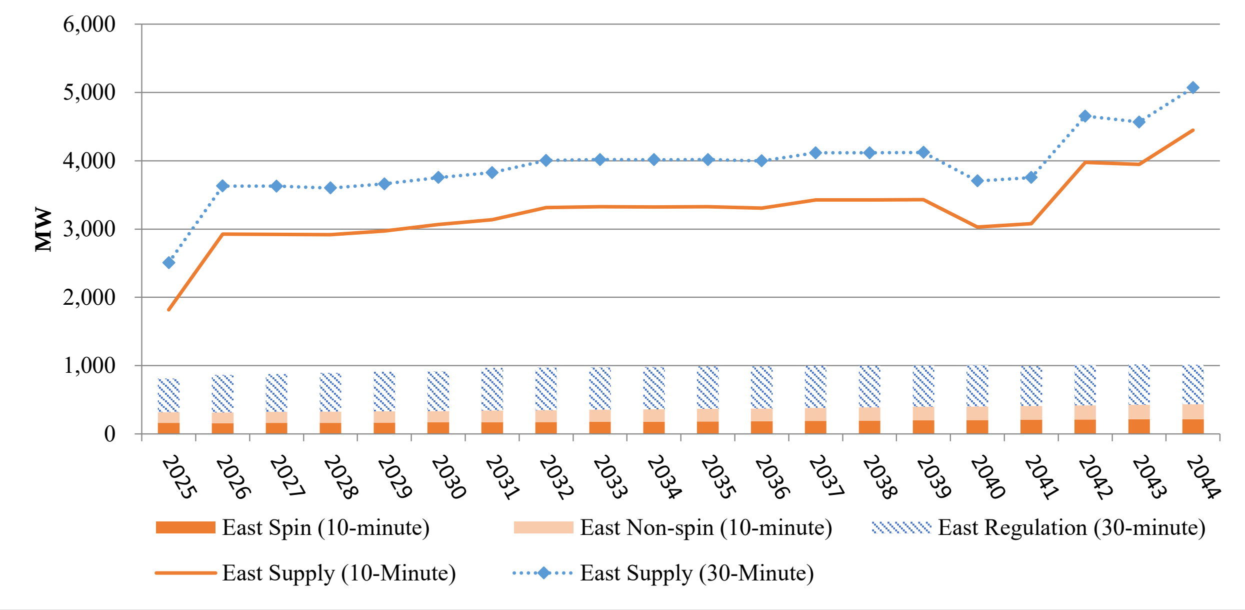
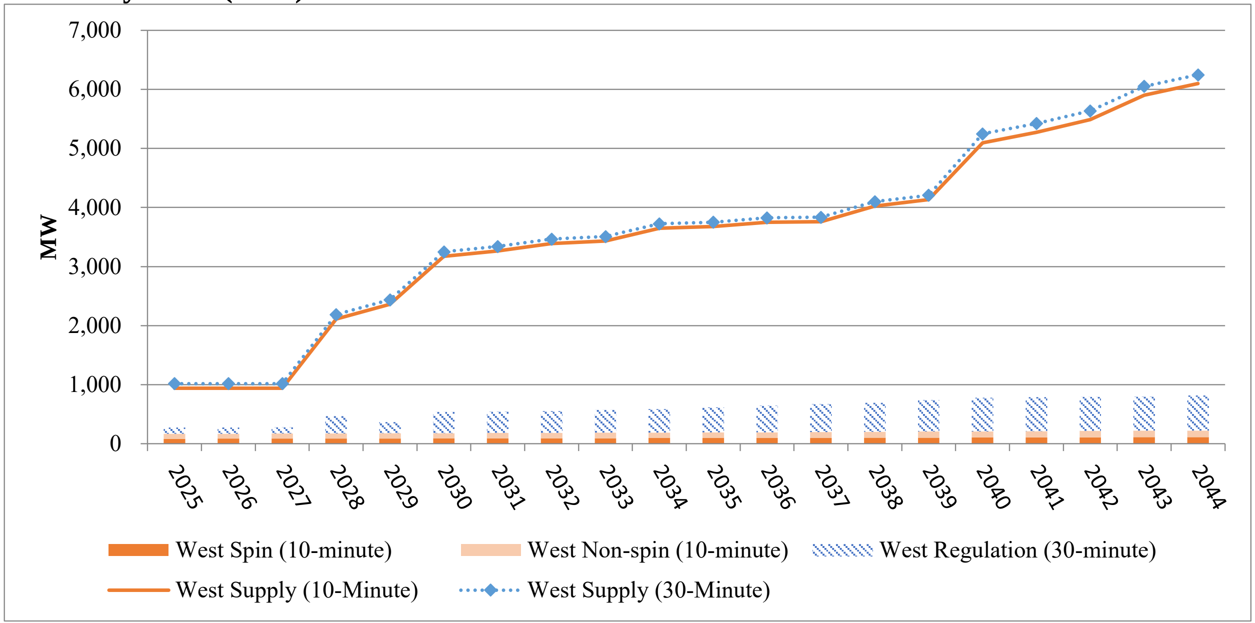



**Figure F.13 - Comparison of Reserve Requirements and Resources, West Balancing Authority Area (MW)**




## Flexible Resource Supply Planning

In actual operations, PacifiCorp has been able to serve its reserve requirements and has not experienced any incidents where it was short of reserve. PacifiCorp manages its resources to meet its reserve obligation in the same manner as meeting its load obligation – through long term planning, market transactions, utilization of the transmission capability between the two balancing authority areas, and operational activities that are performed on an economic basis.

PacifiCorp and the California Independent System Operator Corporation implemented the energy imbalance market (EIM) on November 1, 2014, and participation by other utilities has expanded significantly with more participants scheduled for entry through 2026. By pooling variability in load and resource output, EIM entities reduce the quantity of reserve required to meet flexibility needs. Because variability across different BAAs may happen in opposite directions, the uncertainty requirement for the entire EIM footprint can be less than the sum of individual BAAs' requirements. This difference is known as the "diversity benefit" in the EIM. This diversity benefit reflects offsetting variability and lower combined uncertainty. PacifiCorp's regulation reserve forecast includes a credit to account for the diversity benefits associated with its participation in EIM.

As indicated in OPUC order 12-013, electric vehicle technologies may be able to meet flexible resource needs. Since the 2023 IRP, electric vehicle load control has been one of the demand response options available for selection. While operating reserve supply is projected to be well in excess of operating reserve requirements, the rising supply of zero-cost renewable resources increases the value associated with shifting load within the day and seasonally, rather than just within the hour as contemplated in this appendix.

# APPENDIX G – PLANT WATER CONSUMPTION STUDY

The information provided in this appendix is for PacifiCorp owned plants. Total water consumption and generation includes all owners for jointly owned facilities.

Water intake for each facility is determined by using data acquired from water contracts, water shares and private water rights for each individual facility. Total consumption is the difference between raw water intake and the total water discharged at each respective location. Plant specific water consumption rates are calculated using consumption divided by plant Net MWh production.[1]

For the purposes of water consumption estimates, PacifiCorp is using a four-year average historical model to estimate future water usage. Past water consumption rates have suggested that baseline water usage for thermal generation is consistent year over year with only minor variations in water consumption per Net MWh. 2020-2023 data remained consistent with this model predicting consistent baseline water data. 2023 saw an approximately 25% decrease in Net MWh production while water consumption decreased by around 10% which led to a higher rate of water consumption per MWh produced. The four-year average will remain viable as a predictive model if thermal generation data continues to fall within the range seen in the past four years. If thermal generation decreases significantly, the actual rates will likely be higher than the four-year average, similar to 2023.

[1] Updated water usage was a topic included in stakeholder feedback during the public input meeting series. See Appendix M, stakeholder feedback form #11 (Utah Environmental Caucus).

## Study Data

### Table G.1 – Plant Water Consumption with Acre-Feet* per Year

| | | | Acre-Feet Per Year | | | | | Net MWhs Per Year | | | | 4-year Average | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Plant Name | Zero Discharge | Cooling Media | 2020 | 2021 | 2022 | 2023 | 4-year Average | 2020 | 2021 | 2022 | 2023 | Gals/ MWH | GPM/ MW |
| Chehalis | | Air | 66 | 71 | 47 | 45 | 57 | 2,407,519 | 2,248,237 | 2,172,465 | 2,239,346 | 8 | 0.1 |
| Currant Creek | Yes | Air | 95 | 113 | 85 | 133 | 106 | 2,335,426 | 2,746,290 | 2,805,979 | 2,879,943 | 13 | 0.2 |
| Dave Johnston | | Water | 7,856 | 6,571 | 5,901 | 12,770 | 8,275 | 4,325,604 | 3,601,242 | 3,581,919 | 3,537,695 | 717 | 11.9 |
| Gadsby | | Water | 409 | 339 | 454 | 184 | 346 | 133,410 | 83,008 | 118,821 | 236,930 | 789 | 13.2 |
| Hunter | Yes | Water | 15,103 | 16,326 | 13,426 | 8,788 | 13,411 | 7,988,203 | 9,248,963 | 7,381,184 | 3,410,309 | 624 | 10.4 |
| Huntington | Yes | Water | 7,929 | 12,019 | 11,717 | 7,427 | 9,773 | 4,515,305 | 6,263,658 | 5,673,115 | 3,400,758 | 642 | 10.7 |
| Jim Bridger | Yes | Water | 18,184 | 19,103 | 19,076 | 15,054 | 17,854 | 10,458,575 | 10,342,840 | 10,662,019 | 6,075,458 | 620 | 10.3 |
| Lakeside | | Water | 4,075 | 4,421 | 4,591 | 4,435 | 4,380 | 5,560,112 | 6,389,355 | 6,578,673 | 6,456,506 | 229 | 3.8 |
| Naughton | Yes | Water | 7,622 | 7,236 | 6,929 | 7,570 | 7,339 | 2,659,033 | 2,596,446 | 2,456,201 | 2,766,289 | 913 | 15.2 |
| Wyodak | Yes | Air | 336 | 333 | 324 | 283 | 319 | 1,732,784 | 1,717,528 | 1,779,843 | 1,282,117 | 64 | 1.1 |
| **TOTAL** | | | **61,675** | **66,532** | **62,550** | **56,688** | **61,861** | **42,115,971** | **45,237,567** | **43,210,219** | **32,285,351** | **472** | **7.9** |

* One acre-foot of water is equivalent to 325,851 Gallons or 43,560 Cubic Feet.

Gadsby includes a mix of both Rankine steam units and Brayton peaking gas turbines.

## Table G.2 – Plant Water Consumption by State (acre-feet)

| UTAH PLANTS | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Plant Name** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** |
| Currant Creek | 116 | 110 | 101 | 95 | 113 | 85 | 133 |
| Gadsby | 100 | 205 | 281 | 409 | 339 | 454 | 184 |
| Hunter | 15,383 | 14,751 | 15,808 | 15,103 | 16,326 | 13,426 | 8,788 |
| Huntington | 9,653 | 9,804 | 9,028 | 7,929 | 12,019 | 11,717 | 7,427 |
| Lakeside | 2,698 | 3,648 | 3,894 | 4,075 | 4,421 | 4,591 | 4,435 |
| **TOTAL** | **27,950** | **28,518** | **29,112** | **27,611** | **33,218** | **30,273** | **20,966** |
| Percent of total water consumption = | | 44.4% | | | | | |

| WYOMING PLANTS | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Plant Name** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** |
| Dave Johnston | 8,231 | 8,325 | 8,485 | 7,856 | 6,571 | 5,901 | 12,770 |
| Jim Bridger | 19,047 | 20,067 | 19,893 | 18,184 | 19,103 | 19,076 | 15,054 |
| Naughton | 6,927 | 9,916 | 10,195 | 7,622 | 7,236 | 6,929 | 7,570 |
| Wyodak | 332 | 319 | 292 | 336 | 333 | 324 | 283 |
| **TOTAL** | **34,537** | **38,627** | **38,865** | **33,998** | **33,243** | **32,230** | **35,678** |
| Percent of total water consumption = | | 55.6% | | | | | |

## Table G.3 – Plant Water Consumption for Plants Located in the Upper Colorado River Basin (acre-feet)

| **Plant Name** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** |
|---|---|---|---|---|---|---|---|
| Hunter | 15,383 | 14,751 | 15,808 | 15,103 | 16,326 | 13,426 | 8,788 |
| Huntington | 9,653 | 9,804 | 9,028 | 7,929 | 12,019 | 11,717 | 7,427 |
| Naughton | 6,927 | 9,916 | 10,195 | 7,622 | 7,236 | 6,929 | 7,570 |
| Jim Bridger | 19,047 | 20,067 | 19,893 | 18,184 | 19,103 | 19,076 | 15,054 |
| **TOTAL** | **51,010** | **54,538** | **54,924** | **48,838** | **54,684** | **51,148** | **38,839** |
| Percent of total water consumption = | | 79.6% | | | | | |

## Table G.4 – Plant Water Consumption by Fuel Type (acre-feet)

| COAL FIRED PLANTS | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Plant Name** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** |
| Dave Johnston | 8,231 | 8,325 | 8,485 | 7,856 | 6,571 | 5,901 | 12,770 |
| Hunter | 15,383 | 14,751 | 15,808 | 15,103 | 16,326 | 13,426 | 8,788 |
| Huntington | 9,653 | 9,804 | 9,028 | 7,929 | 12,019 | 11,717 | 7,427 |
| Jim Bridger | 19,047 | 20,067 | 19,893 | 18,184 | 19,103 | 19,076 | 15,054 |
| Naughton | 6,927 | 9,916 | 10,195 | 7,622 | 7,236 | 6,929 | 7,570 |
| Wyodak | 332 | 319 | 292 | 336 | 333 | 324 | 283 |
| **TOTAL** | **59,573** | **63,182** | **63,701** | **57,030** | **61,588** | **57,373** | **51,893** |
| Percent of total water consumption = | | 93.1% | | | | | |

| NATURAL GAS FIRED PLANTS | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Plant Name** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** |
| Currant Creek | 116 | 110 | 101 | 95 | 113 | 85 | 133 |
| Chehalis | 54 | 33 | 63 | 66 | 71 | 47 | 45 |
| Gadsby | 100 | 205 | 281 | 409 | 339 | 454 | 184 |
| Lakeside | 2,698 | 3,648 | 3,894 | 4,075 | 4,421 | 4,591 | 4,435 |
| **TOTAL** | **2,968** | **3,996** | **4,339** | **4,645** | **4,944** | **5,177** | **4,796** |
| Percent of total water consumption = | | 6.9% | | | | | |

# APPENDIX H – STOCHASTICS

## Introduction

For the 2025 IRP, PacifiCorp modified its stochastic analysis to include additional parameters, to capture sustained deviations over the course of a year, and to better reflect the relationships between the various stochastic parameters.

In past IRPs, PacifiCorp calculated stochastic parameters such as volatility and mean reversion to represent most parameters. These parameters produce either normally distributed or log-normally distributed inputs. The normally distributed results for different parameters are then tied together via a correlation matrix. This type of stochastic analysis is well suited so long as the relevant parameters that can be reasonably characterized by a normal distribution. Given the prevalence of wind and solar generation in recent IRPs, PacifiCorp sought to account for risks associated with these technologies. Both technologies are dependent on weather conditions, which is also a factor the influences load, hydro, and market prices, but wind and solar output, particularly on an hourly basis, is not readily characterized using a normal distribution. Upon closer inspection short-term stochastic parameters also miss much of the real-world variation in other parameters, such as 1 in 20 load conditions or dry hydro years, which represent significant deviations from normal. Stochastic parameters can also understate the relationship between different inputs, for example, market prices may experience larger shocks in a dry hydro year or under 1 in 20 load conditions than would be indicated by a normal distribution.

With these factors in mind, the 2025 IRP includes stochastic analysis based on the actual eighteen historical years, from 2006-2023. When PLEXOS uses volatility, mean reversion, and correlation parameters to create stochastic conditions, it produces daily "shock" values that adjust inputs away from their expected values and aligned with other inputs consistent with the correlation inputs. For the 2025 IRP, PacifiCorp is also using daily "shock" values, but they have been calculated from specific historical conditions so that the correlation from history is captured. Rather than independently drawing correlated shocks for a variety of parameters, each stochastic iteration in the 2025 IRP reflects draws of a single historical calendar year for each year of the horizon, and reflects the patterns specific to that historical year for a range of inputs:

- Load (including weather-sensitive energy efficiency): daily variation.
- Market prices (electricity and natural gas): daily variation.
- Hydro: monthly variation.
- Wind and solar: hourly values.
- Thermal outages (existing resources): hourly values.

Once the historical period is identified, the parameters for all inputs are mapped into the forecast period using the same pattern used in PacifiCorp's chaotic normal load forecast, which maintains the day of the week in history and in the forecast while generally keeping contiguous blocks of days together. These patterns provide a representative range of conditions for stochastic analysis.

The stochastic analysis for the 2025 IRP continues to reflect short-run parameters, such that PLEXOS was not allowed to re-optimize its capacity expansion plan based on stochastic results. Certain types of resources may provide greater value in stochastic conditions relative to the normalized conditions used in the capacity expansion process, this concept is analogous to the stochastic risk reduction credit applied to energy efficiency, but it has not been adopted more broadly at this time. Long-run parameters, such as fundamental changes in markets and policy, are addressed through analysis of price-policy scenarios, as discussed in Chapter 8 (Modeling and Portfolio Evaluation).

## Overview

Long-term planning demands specification of how important variables behave over time. For the case of PacifiCorp's long-term planning, important variables include natural gas and electricity prices, regional loads, and regional hydro generation. Modeling these variables involves not only a description of their expected value over time as with a traditional forecast, but also a description of the spread of possible future values. The following sections summarize the development of stochastic process parameters to describe how these uncertain variables evolve over time[1].

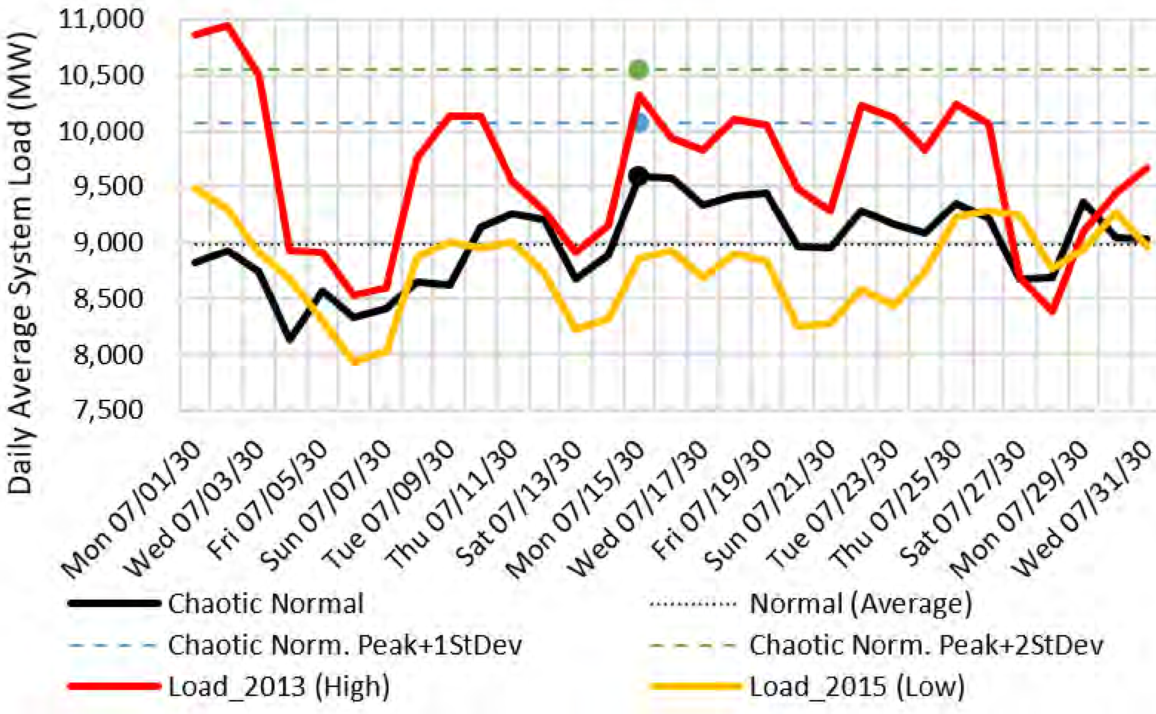
## Stochastic Variables

### Load

For reporting purposes, PacifiCorp produces an estimate of weather-normalized actual load for each of its states at the conclusion of each calendar year. This helps to identify the extent that weather conditions were a driver of retail sales. For the 2025 IRP stochastic analysis, PacifiCorp calculated the % difference between daily average actual load for each state, and the monthly average weather-normalized load for that state. This calculation indicates how much above or below expectations the actual load was on each day. This calculation also retains the possibility that a given month will be above or below normal, as the average of the actual loads need not be equal to the average of the weather-normalized loads in a given month. The daily load factor for each state is applied to all of the load bubbles for that state within PLEXOS, which maintains separate data streams for different jurisdictions, even in areas that are electrically contiguous like Walla Walla (Oregon and Washington) or Northern Utah (Utah, Idaho, Wyoming). Using a load factor, rather than actual hourly load, allows for the impact of load growth over time, as well as changing in the patterns of load, for instance increased customer generation. Figure H.1 shows the variation in forecasted load conditions modeled in the 2025 IRP stochastic analysis. Note that these same load shocks are also applied to the energy efficiency savings from temperature-sensitive bundles (heating and cooling). The savings from these measures is already aligned with PacifiCorp's normalized load forecast (more savings on the highest load data), applying the same shocks to energy efficiency ensures that the savings follows the high load conditions, whenever and as often as they occur. This should increase the value of temperature-sensitive energy efficiency with both higher energy value and reliability benefits.

[1] A stochastic or random process is the counterpart to a deterministic process. Instead of dealing with only one possible reality of how the variables might evolve over time, there is some indeterminacy in the future evolution described by probability distributions or random draws.

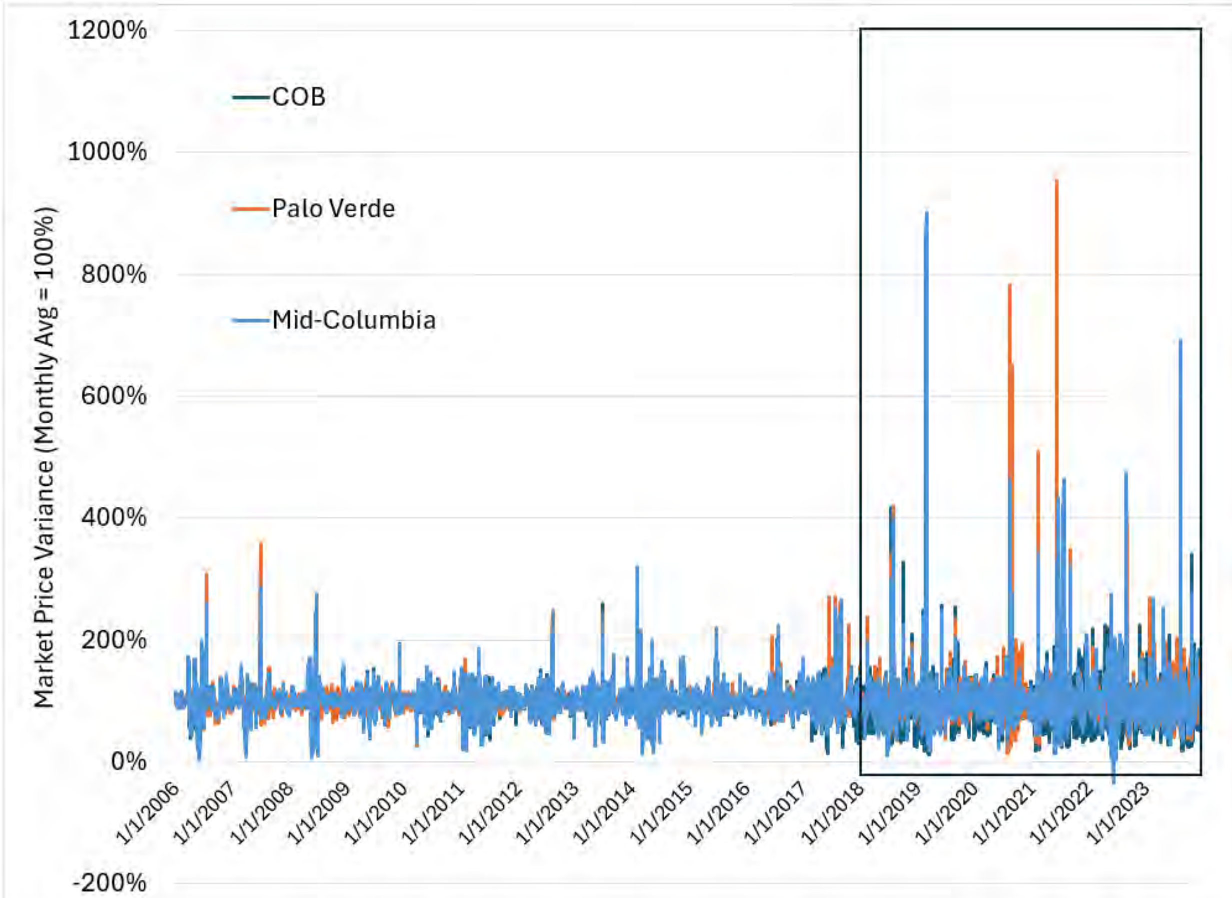
**Figure H.1 – Chaotic Normal and Historical Load Patterns**




## Market Prices

For the 2025 IRP stochastic analysis, PacifiCorp calculated the % difference between daily market actual prices and monthly average actual market prices. Unlike load, PacifiCorp does not have a readily available "normalized" market price, so it is likely that some of the market price response relative to expected conditions is not captured. For example, a wet hydro year would result in a lower monthly average market price on all days, which would not be apparent in the daily price factors. That is just one of many regional factors (i.e., external to PacifiCorp) that impact market prices and could be more thoroughly assessed in future analysis. As a part of the analysis for 2025 IRP, PacifiCorp identified that recent market prices have exhibited significantly higher volatility since 2018, relative to prior years, as shown in Figure H.2. Electricity supply and demand must be matched from moment to moment and volatile market prices may reflect growing concerns that available supply may be insufficient, potentially because of load growth, retirement of dispatchable resources, increasing penetration of renewable resources, and/or more extreme weather conditions. PacifiCorp does not expect these drivers to revert to previous conditions (i.e., lower load, dispatchable resources additions outpacing increases in load, fewer renewables, or less volatile weather), so the variability of historical market prices was increased to align with more recent conditions. This technique retains the relative pattern of pricing across each month while increasing the spread between days with above average prices and days with below average prices.

**Figure H.2 – Historical Market Price Variation**




## Hydro Conditions

Hydro is a relatively small portion of PacifiCorp's portfolio, representing about seven percent of the energy supply in 2025. Because several of its river systems have flexibility to smooth out some variation, notably the Lewis River and Mid-Columbia, PacifiCorp's hydro analysis is based on monthly variation relative to the average of all historical years. The percentage change in hydro output is applied to the climate change-adjusted hydro forecast, so climate impacts continue to be incorporated. Figure H.3 shows that the highest and lowest hydro months are clustered. 2017 has five of the highest months, while 2021 has four of the lowest months. Previous analysis that relied on random weekly draws would have been unlikely to capture this behavior.

**Figure H.3 – Historical Hydro Variation**

| Month | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | Average |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 672 | 487 | 449 | 495 | 523 | 557 | 586 | 411 | 351 | 528 | 448 | 343 | 613 | 384 | 482 | 499 | 393 | 436 | **481** |
| 2 | 600 | 382 | 352 | 336 | 321 | 419 | 595 | 463 | 503 | 464 | 559 | 566 | 471 | 214 | 515 | 335 | 246 | 229 | **421** |
| 3 | 402 | 526 | 363 | 375 | 341 | 506 | 520 | 305 | 570 | 293 | 593 | 644 | 353 | 261 | 296 | 268 | 420 | 228 | **404** |
| 4 | 336 | 380 | 331 | 375 | 328 | 481 | 341 | 349 | 383 | 234 | 356 | 522 | 426 | 390 | 320 | 232 | 261 | 333 | **354** |
| 5 | 393 | 284 | 373 | 503 | 331 | 504 | 392 | 362 | 415 | 202 | 304 | 549 | 337 | 346 | 364 | 258 | 368 | 422 | **373** |
| 6 | 346 | 263 | 467 | 365 | 442 | 438 | 382 | 308 | 251 | 226 | 253 | 430 | 264 | 299 | 279 | 225 | 363 | 291 | **327** |
| 7 | 217 | 230 | 342 | 208 | 249 | 374 | 283 | 236 | 229 | 201 | 204 | 292 | 220 | 210 | 205 | 169 | 226 | 203 | **239** |
| 8 | 194 | 199 | 229 | 133 | 161 | 255 | 244 | 190 | 189 | 136 | 171 | 175 | 173 | 181 | 152 | 125 | 155 | 134 | **178** |
| 9 | 173 | 172 | 200 | 138 | 174 | 260 | 177 | 165 | 147 | 120 | 155 | 262 | 147 | 194 | 78 | 103 | 156 | 191 | **167** |
| 10 | 243 | 253 | 231 | 183 | 279 | 301 | 243 | 287 | 294 | 141 | 439 | 373 | 178 | 260 | 164 | 166 | 189 | 188 | **245** |
| 11 | 623 | 408 | 447 | 396 | 510 | 542 | 597 | 378 | 551 | 442 | 594 | 671 | 316 | 274 | 358 | 535 | 304 | 380 | **463** |
| 12 | 681 | 631 | 315 | 390 | 636 | 436 | 644 | 334 | 651 | 601 | 559 | 630 | 413 | 322 | 457 | 420 | 310 | 561 | **499** |
| **Average** | **406** | **352** | **341** | **325** | **358** | **423** | **416** | **315** | **377** | **298** | **385** | **454** | **325** | **278** | **305** | **277** | **283** | **300** | **348** |
| **% chg** | 16% | 1% | -2% | -7% | 3% | 21% | 19% | -10% | 8% | -14% | 11% | 30% | -7% | -20% | -13% | -20% | -19% | -14% | |

Lowest monthly Highest monthly

## Wind and Solar Output

Wind and solar are already a large part of PacifiCorp's portfolio, representing more than a third of energy supply in 2025 and projected to be more than half of the energy supply by 2030. With the growing reliance on these technologies, their variability is a key component of both cost and reliability. PacifiCorp's transmission system provides access to a wide range of geographic locations. This provides access to locations with the highest annual capacity factors, as well as opportunities for diverse deployment of wind and solar generation to reduce the impact of transmission congestion and localized weather conditions.

For the 2025 IRP, PacifiCorp contracted with Hendrickson Renewables[2] to develop historical hourly wind and solar generation profiles for both its existing portfolio and for proxy resource locations. Some existing resources located in close proximity were evaluated in aggregate for this analysis. The methodology used by Hendrickson Renewables is described below.

For each solar resource, hourly irradiance, and weather data specific to the location were extracted from the Vaisala satellite irradiance dataset and PVsyst model was configured and run for each project site to simulate energy output. For existing facilities, the monthly results were tuned to match historical actual generation from 2020 through 2023. For contracted facilities that do not yet have actual generation data, the results were tuned to match the expected output per the contract. The resulting time series do not include degradation effects, which are applied within the IRP modeling. For proxy locations, annual energy production was reduced by 3% to account for additional availability losses that are not part of the PVsyst model and tuned so that the long-term aggregated energy output matched that targeted annual energy production, again prior to degradation. Small-scale solar resources have the same generation profile as utility-scale in a given location as the technology is equivalent and siting has limited impact on irradiance.

For each existing wind resource, hourly one-hundred-meter wind speeds and air density specific to the location were extracted from the ERA5 reanalysis data set. Wind speeds were also modified

[2] https://hendricksonrenewables.com/

to account for air density effects using International Electrotechnical Commission (IEC) standards. The end result is a project-specific power curve and adjusted wind speed data that aligns with the historical actual generation by month from 2020 through 2023. For each onshore proxy wind resource, the Global Wind Atlas was used to estimate hub-height-specific annual average wind speeds. For the Offshore Brookings project, multiple references were reviewed, and Hendrickson determined a 10.5 m/s annual average wind speed at the specified 137m hub height. Proxy wind projects are also based on the ERA5 dataset and have gross energy production that is reduced by total losses of 20%. Small-scale wind resources may use different technology (such as lower hub heights and smaller turbines) and may be sited in less favorable locations (existing transmission and distribution infrastructure may not be near prime wind sites), so the 2025 IRP includes small-scale-specific wind generation profiles for the west side of its system, where there is greater interest in small-scale resources. Small-scale wind resources on the east side of the system have the same generation profile as utility-scale wind resources in a given location.

Figure H.4 shows the annual variation in proxy wind and solar generation for the variety of potential locations considered in the 2025 IRP. The annual variation in wind is higher solar, with individual locations varying by more than ten percent of the annual output (e.g., a three percent capacity factor decrease on a thirty percent annual capacity factor). The average across the wind fleet can also vary by nearly that amount, as the lowest year (2013) is approximately 9.8% less than the annual average. Solar resources change by a smaller amount as the lowest year (2017) is only 1.8% below the annual average. This annual variation is important, particularly for compliance with clean energy requirements in Oregon and Washington which include annual reporting. But more important to the IRP optimization of costs and reliability is the hourly and daily variation underlying these wind and solar results, the alignment of output with load, market prices, and other wind and solar resources.

**Figure H.4 – Historical Variation of Proxy Wind and Solar Resources**

| Location | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | Base (Avg) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| WD COR | 35% | 30% | 33% | 32% | 37% | 32% | 35% | 27% | 33% | 27% | 37% | 35% | 32% | 29% | 33% | 35% | 31% | 34% | 33% |
| WD CLV | 27% | 30% | 28% | 29% | 30% | 28% | 33% | 25% | 31% | 28% | 33% | 31% | 31% | 31% | 32% | 32% | 30% | 26% | 30% |
| WD BOR/GOE | 31% | 32% | 30% | 27% | 30% | 35% | 35% | 28% | 33% | 28% | 31% | 33% | 31% | 28% | 32% | 31% | 28% | 25% | 30% |
| WD HTG | 23% | 25% | 28% | 28% | 28% | 29% | 27% | 26% | 29% | 23% | 26% | 26% | 30% | 26% | 29% | 28% | 29% | 24% | 27% |
| WD NTN/NUT/WSF | 29% | 31% | 33% | 30% | 31% | 32% | 32% | 28% | 35% | 28% | 32% | 30% | 31% | 30% | 34% | 33% | 30% | 23% | 31% |
| WD SOR (Offshore) | 55% | 45% | 49% | 47% | 55% | 50% | 49% | 44% | 50% | 46% | 50% | 48% | 46% | 47% | 48% | 55% | 43% | 52% | 49% |
| WD SOR/SUM | 38% | 33% | 36% | 33% | 41% | 34% | 37% | 29% | 37% | 30% | 39% | 35% | 32% | 34% | 33% | 37% | 32% | 35% | 35% |
| WD UTS | 27% | 29% | 29% | 30% | 29% | 29% | 30% | 25% | 29% | 28% | 31% | 32% | 30% | 30% | 32% | 31% | 31% | 28% | 29% |
| WD WWA | 36% | 34% | 36% | 32% | 34% | 38% | 37% | 30% | 35% | 28% | 34% | 31% | 34% | 26% | 39% | 36% | 29% | 28% | 33% |
| WD WMV | 41% | 38% | 40% | 38% | 39% | 38% | 41% | 33% | 40% | 34% | 39% | 41% | 37% | 33% | 40% | 41% | 35% | 38% | 38% |
| WD BDG/WYC | 37% | 36% | 41% | 35% | 38% | 43% | 39% | 39% | 43% | 35% | 39% | 39% | 39% | 39% | 42% | 40% | 40% | 32% | 39% |
| WD DJW/WYE | 43% | 41% | 44% | 41% | 40% | 46% | 43% | 42% | 42% | 38% | 43% | 40% | 38% | 41% | 44% | 40% | 44% | 42% | 42% |
| WD WYN | 42% | 40% | 39% | 37% | 36% | 42% | 41% | 38% | 39% | 36% | 41% | 38% | 35% | 35% | 39% | 41% | 41% | 33% | 39% |
| WD YAK | 31% | 31% | 32% | 32% | 31% | 33% | 32% | 29% | 34% | 28% | 30% | 27% | 31% | 28% | 35% | 34% | 28% | 28% | 31% |
| **Average Utility Scale WD** | **35.5%** | **33.9%** | **35.6%** | **33.7%** | **35.6%** | **36.4%** | **36.5%** | **31.7%** | **36.4%** | **31.2%** | **36.0%** | **34.8%** | **34.0%** | **32.6%** | **36.6%** | **36.7%** | **33.7%** | **32.0%** | **34.6%** |
| **Location** | **2006** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** | **Base (Avg)** |
| PV CLV | 32% | 32% | 33% | 32% | 32% | 32% | 32% | 31% | 32% | 32% | 32% | 32% | 32% | 32% | 33% | 32% | 32% | 32% | 32% |
| PV BOR/GOE | 27% | 28% | 28% | 28% | 27% | 28% | 27% | 28% | 28% | 28% | 28% | 27% | 28% | 28% | 28% | 28% | 28% | 28% | 28% |
| PV HTG | 29% | 29% | 30% | 30% | 29% | 29% | 29% | 28% | 29% | 29% | 29% | 29% | 30% | 29% | 30% | 29% | 30% | 29% | 29% |
| PV NTN/NUT/WSF | 29% | 30% | 29% | 29% | 29% | 29% | 29% | 28% | 29% | 29% | 29% | 28% | 29% | 29% | 30% | 29% | 29% | 29% | 29% |
| PV COR | 31% | 31% | 31% | 31% | 30% | 31% | 31% | 31% | 31% | 31% | 31% | 30% | 31% | 31% | 32% | 32% | 31% | 31% | 31% |
| PV SOR/SUM | 29% | 30% | 29% | 30% | 29% | 29% | 29% | 29% | 29% | 29% | 29% | 28% | 29% | 29% | 30% | 29% | 30% | 29% | 29% |
| PV UTS | 30% | 32% | 31% | 31% | 31% | 31% | 31% | 31% | 32% | 31% | 31% | 32% | 31% | 31% | 33% | 31% | 31% | 31% | 31% |
| PV WWA | 26% | 26% | 26% | 26% | 26% | 25% | 25% | 26% | 26% | 27% | 27% | 25% | 26% | 26% | 26% | 27% | 25% | 26% | 26% |
| PV WMV | 25% | 24% | 23% | 24% | 24% | 23% | 24% | 24% | 25% | 25% | 24% | 24% | 25% | 25% | 24% | 26% | 24% | 25% | 24% |
| PV BDG/WYC | 28% | 29% | 29% | 29% | 29% | 28% | 29% | 28% | 29% | 29% | 29% | 28% | 30% | 29% | 30% | 29% | 29% | 28% | 29% |
| PV DJW/WYE | 27% | 28% | 27% | 27% | 28% | 27% | 28% | 27% | 27% | 27% | 28% | 27% | 27% | 27% | 29% | 27% | 28% | 27% | 27% |
| PV WYN | 28% | 27% | 28% | 27% | 28% | 27% | 28% | 27% | 26% | 27% | 28% | 27% | 27% | 27% | 28% | 27% | 27% | 27% | 27% |
| PV YAK | 27% | 27% | 27% | 27% | 26% | 27% | 26% | 27% | 27% | 27% | 28% | 26% | 27% | 26% | 28% | 28% | 27% | 27% | 27% |
| **Average Utility Scale PV** | **28.1%** | **28.6%** | **28.2%** | **28.5%** | **28.3%** | **28.1%** | **28.6%** | **28.0%** | **28.2%** | **28.4%** | **28.6%** | **27.9%** | **28.7%** | **28.3%** | **29.5%** | **28.6%** | **28.7%** | **28.0%** | **28.4%** |

## Thermal Outages

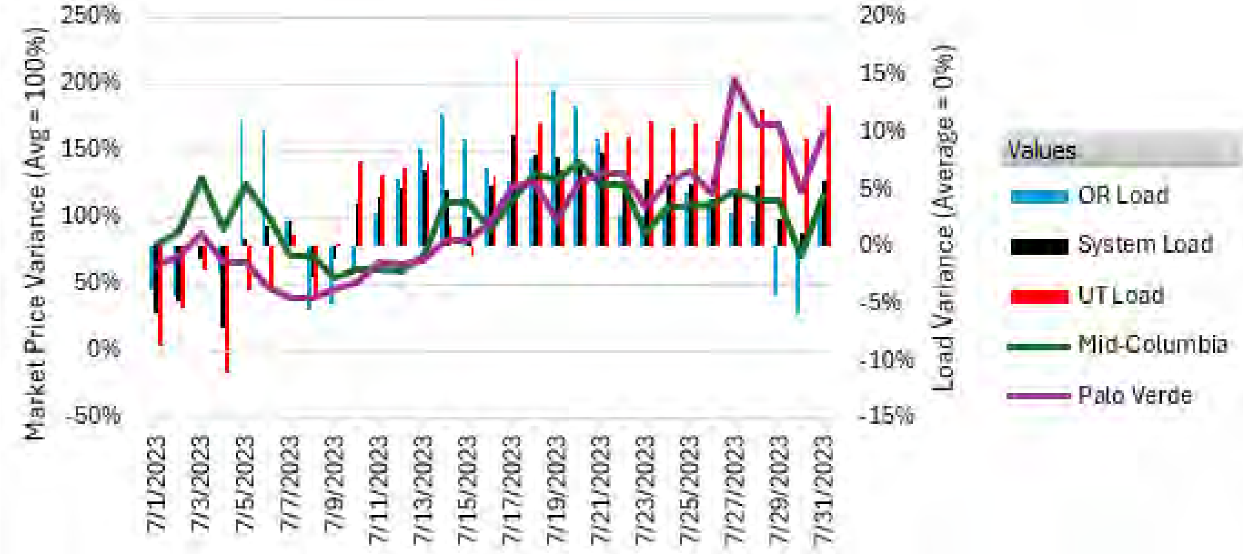
PacifiCorp used NERC-GADS data reported for its existing thermal fleet to identify the start and end times for forced outages, maintenance outages, and derates at each unit. The actual outage events from history are replicated in the forecast period.

# Correlated Inputs

While the variation in individual inputs is a valuable enhancement, the patterns and range of conditions when considering multiple inputs is where this historical data technique really surpasses PacifiCorp's previous stochastic techniques. Figure H.5 shows the pattern of market prices and load during July 2023, while Figure H.6 shows October 2020.

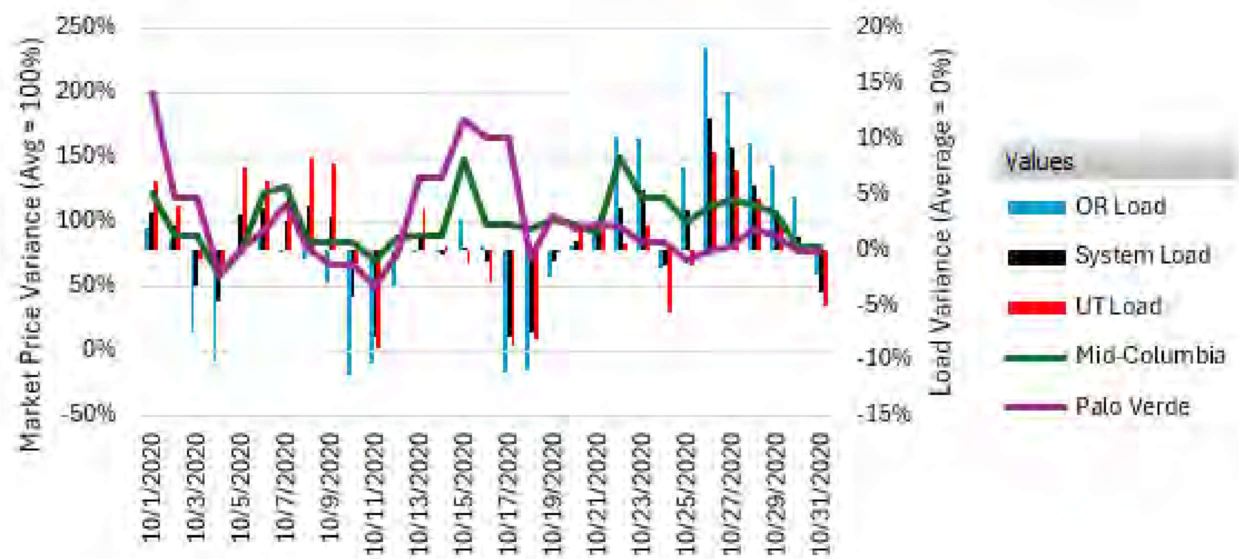
Actual loads for July 2023 were somewhat above the median weather-normalized level. The pattern across the month shows that market prices tend to be higher when loads are high, and vice versa. This relationship between market prices and PacifiCorp's load is common. Prices also reflect other factors, including renewable resource output, and loads of other utilities in the region.

**Figure H.5 -- Historical Market Prices vs Load, July 2023**




Actual loads for October 2020 were close to the median weather-normalized level. Loads are particularly low on weekends (e.g., Oct. 3, 2020, is a Saturday). Price variation also occurs outside of PacifiCorp's peak load days, as a result of regional conditions. In actual operations, correlation is not perfect, so it is not intended to be so for forecasting.

**Figure H.6 – Historical Market Prices vs Load, October 2020**



# Appendix I – Capacity Expansion Results

The tables below provide the full portfolio expansion results for each case with a distinct portfolio in the 2025 IRP. Maps of PacifiCorp's service area overlaid with 2025 IRP preferred portfolio incremental resource additions by location are also presented. See the below tables for a list of cases presented here.

**Table I.1 – Price-Policy Case Definitions**

| Price-Policy | Existing Coal(b) | Existing Gas(b) | Other Existing Resources | Proxy Resources(c) |
|---|---|---|---|---|
| MN | Optimized | Optimized | End of Life | All allowed |
| MR | Optimized | Optimized | End of Life | All allowed |
| LN | Optimized | Optimized | End of Life | All allowed |
| HH | Optimized | Optimized | End of Life | All allowed |
| SC | Optimized | Optimized | End of Life | All allowed |

(a) Thermal coal and gas resources are endogenously optimized for retirements, conversions, and technology installations.
(b) Optimized proxy portfolio selections include renewables, offshore wind, storage, natural gas, transmission, DSM, purchases, and sales, etc.

**Table I.2 – 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 |

# 2025 IRP Portfolio Maps

## Preferred Portfolio

### Figure I.1: 2025 IRP Preferred Portfolio Incremental Resource Additions 2025-2030

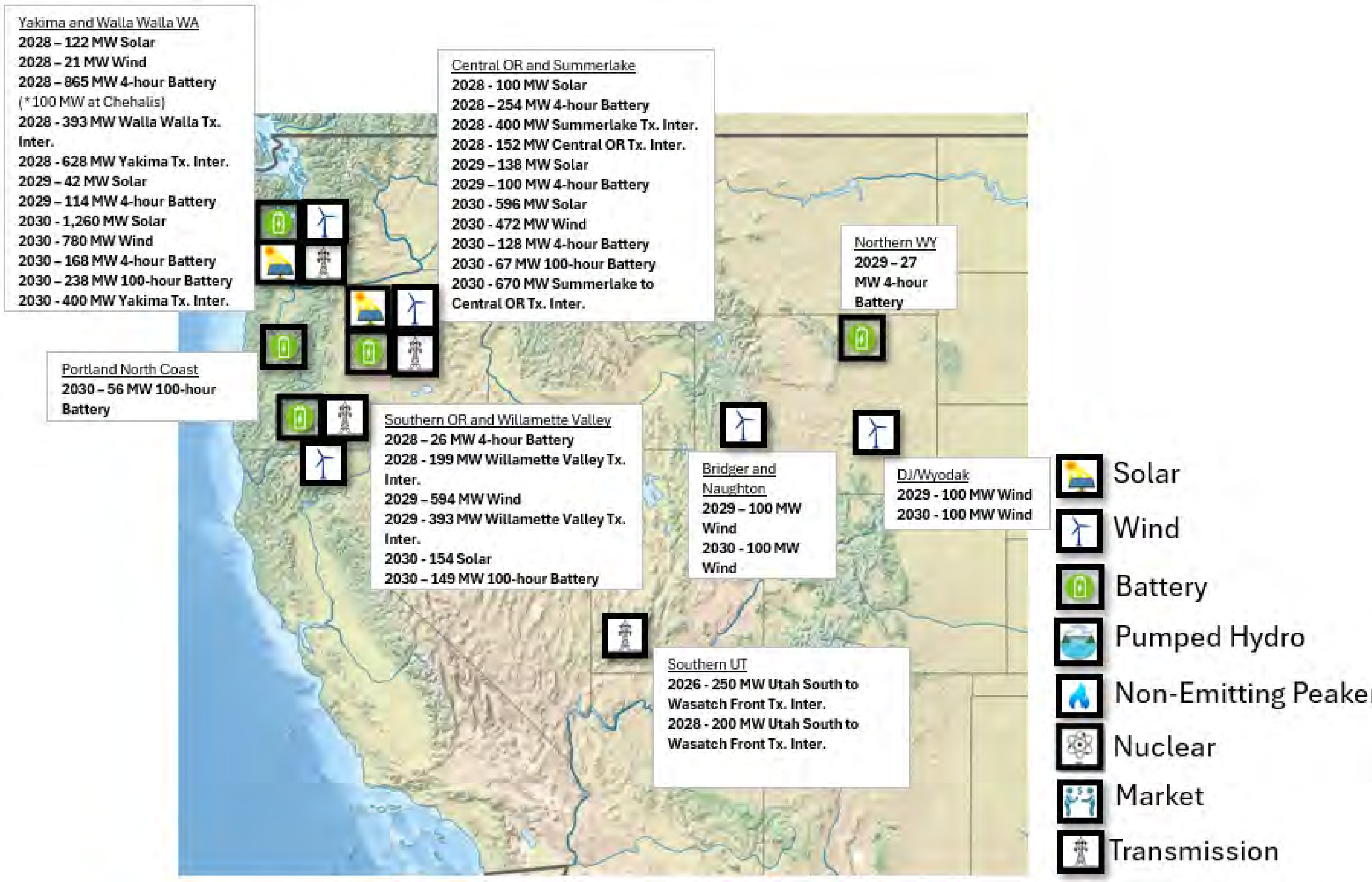


**Figure I.2: 2025 IRP Preferred Portfolio Incremental Resource Additions 2031-2035**

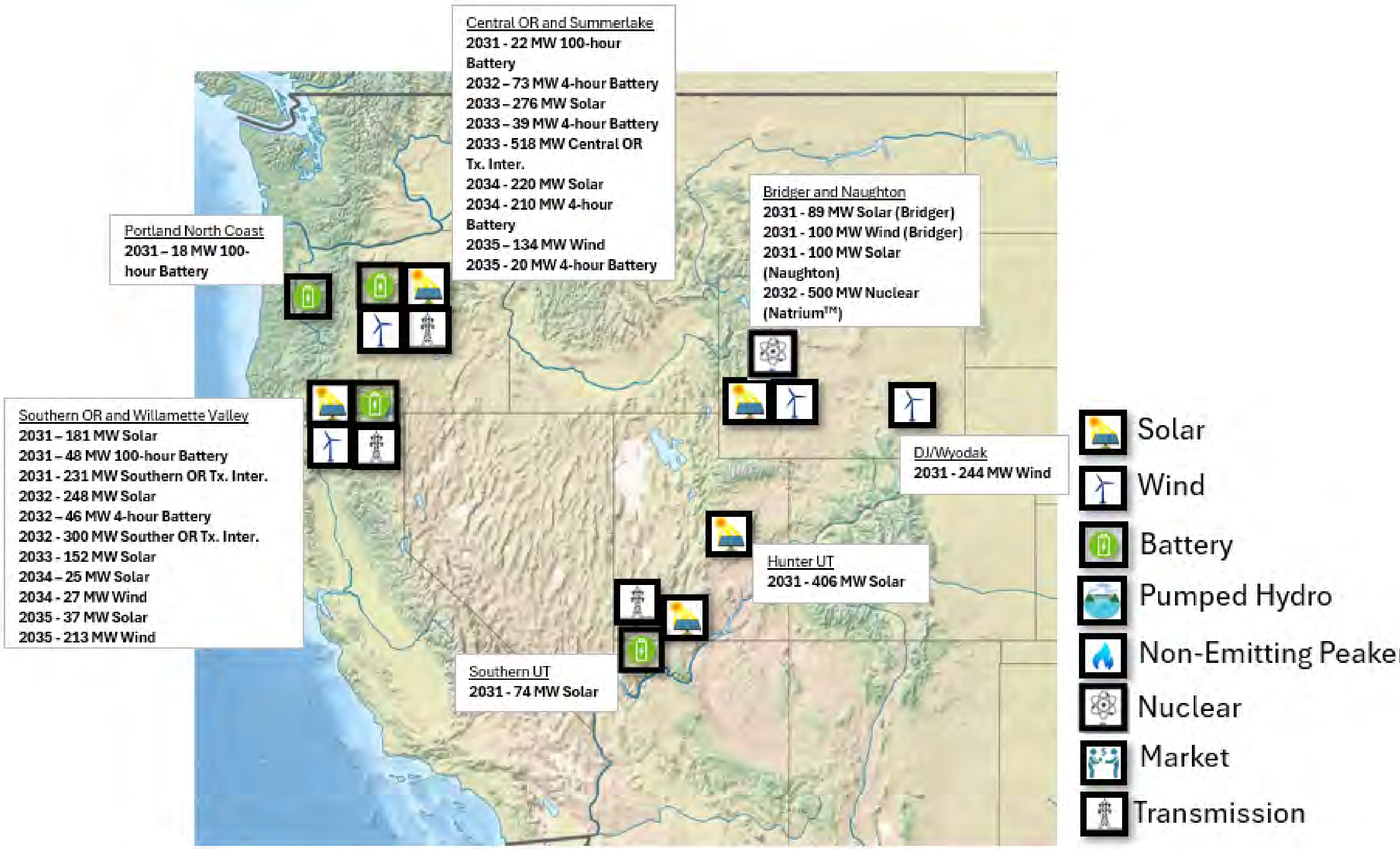


**Figure I.3: 2025 IRP Preferred Portfolio Incremental Resource Additions 2036-2040**

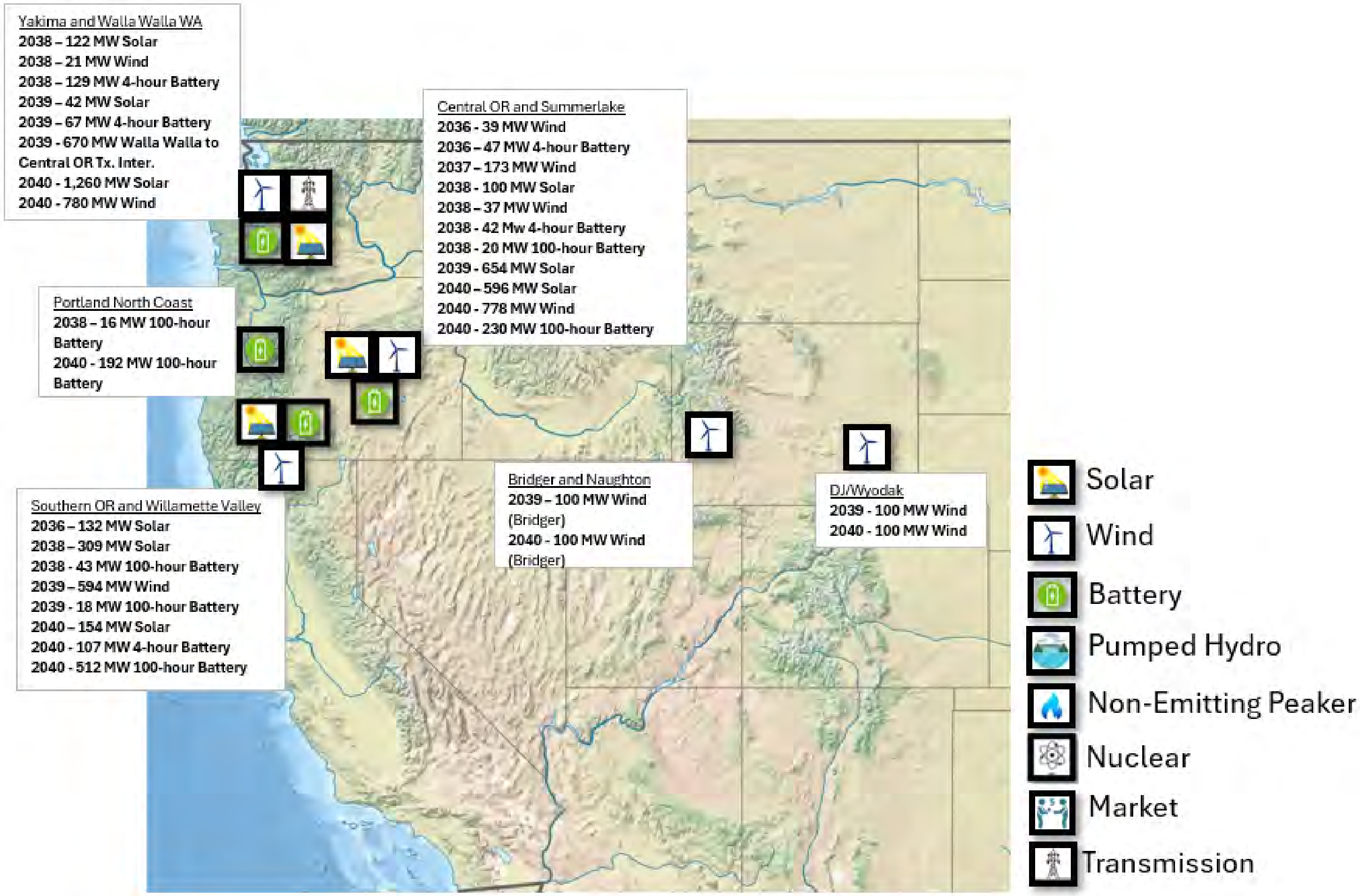
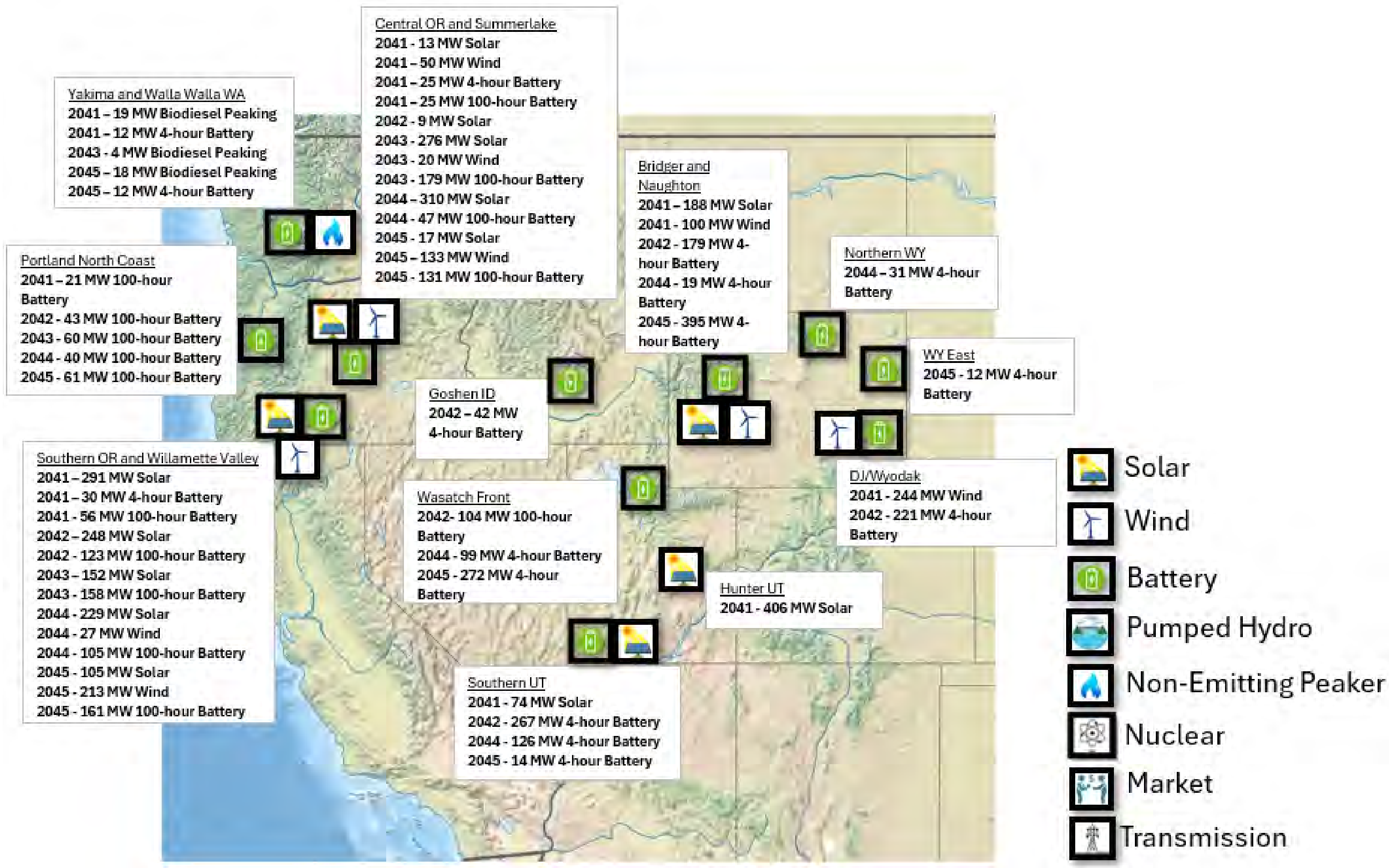


**Figure I.4: 20 IRP Preferred Portfolio Incremental Resource Additions 2041-2045**



# 2025 IRP Portfolio Summaries

## Preferred Portfolio

| Summary Portfolio Capacity by Resource Type and Year, Installed MW | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | | |
| Resource | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | Total |
| **Expansion Options** | | | | | | | | | | | | | | | | | | | | | | |
| Gas - CCCT | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Gas - Peaking | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Nuclear | - | - | - | - | - | - | - | 500 | - | - | - | - | - | - | - | - | - | - | - | - | - | 500 |
| Renewable Peaking | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 19 | - | 4 | - | 18 | 41 |
| DSM - Energy Efficiency | 92 | 89 | 209 | 220 | 239 | 261 | 329 | 291 | 299 | 295 | 299 | 315 | 347 | 314 | 293 | 301 | 303 | 315 | 238 | 205 | 182 | 5,436 |
| DSM - Demand Response | 18 | 2 | - | 63 | 21 | 120 | 99 | 5 | 1 | 3 | 3 | 21 | 112 | 18 | 5 | 24 | 61 | 106 | 29 | 26 | 52 | 789 |
| Renewable - Wind | - | - | - | 21 | 794 | 1,452 | 344 | 1 | - | 29 | 347 | 40 | 175 | 37 | - | 376 | 50 | - | 20 | - | 96 | 3,782 |
| Renewable - Small Scale Wind | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Utility Solar | - | - | - | 222 | 180 | 1,690 | 849 | 240 | 403 | 225 | 13 | - | 1 | - | 554 | 104 | 12 | - | - | 197 | 75 | 4,765 |
| Renewable - Small Scale Solar | - | - | - | - | - | 320 | 2 | 18 | 26 | 21 | 30 | 132 | - | 309 | - | - | 110 | - | - | 143 | 36 | 1,147 |
| Renewable - Geothermal | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Battery, < 8 hour | - | - | - | 1,146 | 242 | 296 | - | 119 | 39 | 210 | 20 | 47 | - | 175 | 67 | 113 | 67 | 713 | 5 | 459 | 733 | 4,451 |
| Renewable - Battery, 8-23 hour | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Battery, 24+ hour | - | - | - | - | - | 511 | 91 | 3 | 4 | 3 | 4 | 4 | 11 | 83 | 37 | 939 | 107 | 319 | 402 | 197 | 358 | 3,073 |
| Other Renewable | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Storage - Other | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | | | | | | | | | | | | | | | | | | |
| **Existing Unit Changes** | | | | | | | | | | | | | | | | | | | | | | |
| Coal Plant Retirements - Minority Own | - | (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** | |

# Oregon Full Jurisdictional Portfolio

| Summary Portfolio Capacity by Resource Type and Year, Installed MW | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | | |
| Resource | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | Total |
| **Expansion Options** | | | | | | | | | | | | | | | | | | | | | | |
| Gas - CCCT | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Gas - Peaking | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Nuclear | - | - | - | - | - | - | - | 500 | - | - | - | - | - | - | - | - | - | - | - | - | - | 500 |
| Renewable Peaking | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 19 | - | 4 | - | 18 | 41 |
| DSM - Energy Efficiency | 92 | 89 | 201 | 209 | 220 | 237 | 306 | 280 | 283 | 280 | 300 | 309 | 333 | 303 | 283 | 291 | 266 | 286 | 252 | 230 | 189 | 5,239 |
| DSM - Demand Response | 18 | 2 | - | 53 | 17 | 9 | 53 | 5 | 1 | 3 | 3 | 11 | 259 | 15 | 50 | 23 | 4 | 100 | 9 | 50 | 25 | 710 |
| Renewable - Wind | - | - | - | 21 | 260 | 1,066 | 100 | 51 | - | 29 | 347 | 40 | 175 | 37 | - | 376 | 50 | - | 20 | - | 96 | 2,668 |
| Renewable - Small Scale Wind | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Utility Solar | - | - | - | 122 | 99 | 1,871 | 19 | 220 | 315 | 225 | 13 | - | - | - | 554 | 104 | 12 | - | - | 197 | 75 | 3,826 |
| Renewable - Small Scale Solar | - | - | - | - | - | 320 | 2 | 18 | 26 | 21 | 30 | 132 | - | 309 | - | - | 110 | - | - | 143 | 36 | 1,147 |
| Renewable - Geothermal | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Battery, < 8 hour | - | - | - | 876 | 255 | 228 | 31 | 119 | 39 | 210 | 20 | 83 | - | 104 | 100 | 314 | 58 | - | 2 | - | - | 2,439 |
| Renewable - Battery, 8-23 hour | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 17 | 224 | - | - | - | - | - | 241 |
| Renewable - Battery, 24+ hour | - | - | - | - | - | 134 | - | - | - | - | - | - | - | 59 | 4 | 752 | 128 | - | 341 | - | 59 | 1,477 |
| Other Renewable | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Storage - Other | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 1 | |
| | | | | | | | | | | | | | | | | | | | | | | |
| **Existing Unit Changes** | | | | | | | | | | | | | | | | | | | | | | |
| Coal Plant Retirements - Minority Own | - | (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)** | |

# Washington Full Jurisdictional Portfolio

| Summary Portfolio Capacity by Resource Type and Year, Installed MW | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | | |
| Resource | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | Total |
| **Expansion Options** | | | | | | | | | | | | | | | | | | | | | | |
| Gas - CCCT | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Gas - Peaking | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Nuclear | - | - | - | - | - | - | - | 500 | - | - | - | - | - | - | - | - | - | - | - | - | - | 500 |
| Renewable Peaking | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| DSM - Energy Efficiency | 92 | 89 | 224 | 235 | 215 | 234 | 289 | 287 | 291 | 290 | 316 | 323 | 356 | 324 | 304 | 293 | 278 | 302 | 268 | 234 | 186 | 5,430 |
| DSM - Demand Response | 18 | 2 | 2 | 197 | 5 | 17 | - | - | - | - | - | 43 | - | 17 | 24 | 8 | 5 | 331 | 31 | 27 | 107 | 834 |
| Renewable - Wind | - | - | - | - | 1,607 | - | 260 | 1 | - | - | - | - | - | - | - | - | - | - | - | - | - | 1,868 |
| Renewable - Small Scale Wind | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Utility Solar | - | - | - | 201 | 138 | 463 | 1,437 | 770 | 527 | 418 | 772 | 249 | 100 | 1 | - | - | - | - | - | - | - | 5,076 |
| Renewable - Small Scale Solar | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Geothermal | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Battery, < 8 hour | - | - | 38 | 856 | 232 | 1,376 | - | - | - | - | - | - | - | 129 | 67 | 66 | 129 | 149 | 646 | 170 | 1,357 | 5,215 |
| Renewable - Battery, 8-23 hour | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Battery, 24+ hour | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Other Renewable | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Storage - Other | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | |
| | | | | | | | | | | | | | | | | | | | | | | |
| **Existing Unit Changes** | | | | | | | | | | | | | | | | | | | | | | |
| Coal Plant Retirements - Minority Own | - | (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** | |

# Utah, Idaho, Wyoming, California (UIWC) Full Jurisdictional Portfolio

| Summary Portfolio Capacity by Resource Type and Year, Installed MW | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | | |
| Resource | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | Total |
| **Expansion Options** | | | | | | | | | | | | | | | | | | | | | | |
| Gas - CCCT | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Gas - Peaking | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Nuclear | - | - | - | - | - | - | - | 500 | - | - | - | - | - | - | - | - | - | - | - | - | - | 500 |
| Renewable Peaking | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| DSM - Energy Efficiency | 92 | 89 | 164 | 170 | 182 | 196 | 270 | 236 | 247 | 251 | 261 | 286 | 312 | 284 | 278 | 257 | 252 | 283 | 216 | 200 | 165 | 4,691 |
| DSM - Demand Response | 18 | 2 | - | 2 | 7 | 112 | 99 | - | - | - | 5 | 39 | 115 | 3 | - | 4 | 70 | 106 | 43 | 30 | 32 | 687 |
| Renewable - Wind | - | - | - | - | 306 | 684 | 344 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 1,334 |
| Renewable - Small Scale Wind | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Utility Solar | - | - | - | 153 | 12 | 79 | 668 | - | 31 | 123 | 133 | 3 | - | - | - | 2 | - | - | - | 65 | - | 1,269 |
| Renewable - Small Scale Solar | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Geothermal | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Battery, < 8 hour | - | - | - | 193 | 71 | 224 | - | - | - | - | 85 | 171 | 4 | 474 | 249 | 140 | 469 | 713 | 896 | 1,097 | 733 | 5,519 |
| Renewable - Battery, 8-23 hour | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Battery, 24+ hour | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 104 | - | - | - | 104 |
| Other Renewable | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Storage - Other | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | | | | | | | | | | | | | | | | | | |
| **Existing Unit Changes** | | | | | | | | | | | | | | | | | | | | | | |
| Coal Plant Retirements - Minority Own | - | (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** | |

# MN No CCS

| Summary Portfolio Capacity by Resource Type and Year, Installed MW | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | | |
| Resource | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | Total |
| **Expansion Options** | | | | | | | | | | | | | | | | | | | | | | |
| Gas - CCCT | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Gas - Peaking | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Nuclear | - | - | - | - | - | - | - | 500 | - | - | - | - | - | - | - | - | - | - | - | - | - | 500 |
| Renewable Peaking | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 19 | - | 4 | - | 18 | 41 |
| DSM - Energy Efficiency | 92 | 89 | 207 | 218 | 229 | 253 | 326 | 287 | 284 | 282 | 294 | 300 | 333 | 312 | 292 | 289 | 304 | 315 | 260 | 232 | 219 | 5,417 |
| DSM - Demand Response | 18 | 2 | - | 63 | 19 | 34 | 187 | 5 | 1 | 3 | 3 | 21 | 93 | 18 | 5 | 25 | 6 | 176 | 30 | 26 | 50 | 785 |
| Renewable - Wind | - | - | - | 21 | 594 | 1,252 | 276 | 1 | - | 29 | 347 | 40 | 175 | 37 | - | 376 | 50 | - | 20 | - | 96 | 3,314 |
| Renewable - Small Scale Wind | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Utility Solar | - | - | - | 222 | 180 | 1,690 | 614 | 240 | 403 | 225 | 13 | - | 1 | - | 554 | 104 | 12 | - | - | 197 | 75 | 4,530 |
| Renewable - Small Scale Solar | - | - | - | - | - | 320 | 2 | 18 | 26 | 21 | 30 | 132 | - | 309 | - | - | 110 | - | - | 143 | 36 | 1,147 |
| Renewable - Geothermal | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Battery, < 8 hour | - | - | 2 | 1,146 | 215 | 299 | - | 119 | 39 | 210 | 20 | 47 | - | 175 | 188 | 113 | 67 | 115 | 5 | 758 | - | 3,518 |
| Renewable - Battery, 8-23 hour | - | - | 1 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 1 |
| Renewable - Battery, 24+ hour | - | - | - | - | - | 511 | 91 | 3 | 4 | 3 | 4 | 4 | 11 | 83 | 37 | 939 | 107 | 261 | 402 | 197 | 358 | 3,015 |
| Other Renewable | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Storage - Other | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | | | | | | | | | | | | | | | | | | |
| **Existing Unit Changes** | | | | | | | | | | | | | | | | | | | | | | |
| Coal Plant Retirements - Minority Own | - | (82) | - | (33) | (123) | (148) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (386) |
| Coal Plant Retirements | - | - | - | (220) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (220) |
| Coal Plant Ceases as Coal | - | (357) | - | - | (205) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (562) |
| Coal - CCS | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Coal - Gas Conversions | - | 357 | - | - | 205 | - | - | - | - | - | - | - | - | - | - | - | - | - | (403) | - | - | 159 |
| 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** | **210** | **1,415** | **1,114** | **4,112** | **1,287** | **1,173** | **757** | **770** | **711** | **544** | **513** | **902** | **1,076** | **1,846** | **277** | **867** | **271** | **1,320** | **832** | |

# MR No CCS

| Summary Portfolio Capacity by Resource Type and Year, Installed MW | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | | |
| Resource | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | Total |
| **Expansion Options** | | | | | | | | | | | | | | | | | | | | | | |
| Gas - CCCT | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Gas - Peaking | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Nuclear | - | - | - | - | - | - | - | 500 | - | - | - | - | - | - | - | - | - | - | - | - | - | 500 |
| Renewable Peaking | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 19 | - | 4 | - | 18 | 41 |
| DSM - Energy Efficiency | 92 | 89 | 207 | 218 | 230 | 251 | 302 | 288 | 282 | 271 | 292 | 302 | 345 | 314 | 293 | 301 | 304 | 315 | 270 | 246 | 219 | 5,431 |
| DSM - Demand Response | 18 | 2 | - | 63 | 19 | 16 | - | 5 | 1 | 3 | 3 | 19 | 2 | 18 | 5 | 27 | 8 | 467 | 11 | 44 | 51 | 782 |
| Renewable - Wind | - | - | - | 21 | 594 | 2,857 | - | 1 | - | 29 | 347 | 40 | 175 | 37 | - | 376 | 50 | - | 20 | - | 96 | 4,643 |
| Renewable - Small Scale Wind | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Utility Solar | - | - | - | 222 | 180 | 1,690 | 681 | 891 | 503 | 325 | 68 | - | 1 | - | 554 | 104 | 12 | - | - | 197 | 75 | 5,503 |
| Renewable - Small Scale Solar | - | - | - | - | - | 320 | 2 | 18 | 26 | 21 | 30 | 132 | - | 309 | - | - | 110 | - | - | 143 | 36 | 1,147 |
| Renewable - Geothermal | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Battery, < 8 hour | - | - | 2 | 1,146 | 215 | 1,002 | - | 119 | 39 | 210 | 20 | 47 | - | 175 | 67 | 131 | 67 | - | 5 | 163 | 907 | 4,315 |
| Renewable - Battery, 8-23 hour | - | - | 1 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 1 |
| Renewable - Battery, 24+ hour | - | - | - | - | - | 522 | 91 | 3 | 4 | 3 | 4 | 4 | 11 | 83 | 37 | 939 | 107 | 315 | 402 | 197 | 362 | 3,084 |
| Other Renewable | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Storage - Other | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | | | | | | | | | | | | | | | | | | |
| **Existing Unit Changes** | | | | | | | | | | | | | | | | | | | | | | |
| Coal Plant Retirements - Minority Own | - | (82) | - | (33) | (123) | (148) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (386) |
| Coal Plant Retirements | - | - | - | (220) | - | - | (418) | (268) | - | - | - | - | - | - | - | - | - | - | - | - | - | (906) |
| Coal Plant Ceases as Coal | - | (357) | - | - | (205) | (2,679) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (3,241) |
| Coal - CCS | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Coal - Gas Conversions | - | 357 | - | - | 205 | 2,679 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 3,241 |
| 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) | (2) | (52) |
| Expire - Other | - | 520 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (20) | 500 |
| | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | | | | | | | | | | | | | | | | | | |
| **Total** | **110** | **464** | **210** | **1,415** | **1,115** | **6,411** | **449** | **1,557** | **855** | **859** | **764** | **544** | **434** | **904** | **956** | **1,878** | **279** | **1,097** | **665** | **757** | **1,742** | |

# No Nuclear

| Summary Portfolio Capacity by Resource Type and Year, Installed MW | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | | |
| Resource | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | Total |
| **Expansion Options** | | | | | | | | | | | | | | | | | | | | | | |
| Gas - CCCT | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Gas - Peaking | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Nuclear | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable Peaking | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| DSM - Energy Efficiency | 92 | 89 | 210 | 220 | 237 | 256 | 331 | 314 | 310 | 299 | 299 | 314 | 324 | 267 | 283 | 251 | 286 | 299 | 282 | 261 | 220 | 5,444 |
| DSM - Demand Response | 18 | 2 | - | 63 | 20 | 136 | 13 | 8 | 26 | 79 | 32 | 4 | 70 | 14 | 151 | 24 | 46 | 31 | 12 | 102 | 48 | 899 |
| Renewable - Wind | - | - | - | - | 500 | 1,728 | 300 | 301 | 302 | 322 | 380 | 292 | 2 | - | - | - | - | - | - | - | - | 4,127 |
| Renewable - Small Scale Wind | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Utility Solar | - | - | - | 656 | - | 1,444 | 962 | 299 | 326 | 395 | 456 | 391 | 1 | - | - | - | - | - | - | 22 | 108 | 5,060 |
| Renewable - Small Scale Solar | - | - | - | - | - | 320 | 2 | 18 | 26 | 21 | 26 | 53 | - | 307 | - | 49 | 153 | - | 10 | 126 | 36 | 1,147 |
| Renewable - Geothermal | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Battery, < 8 hour | - | - | 16 | 1,399 | 109 | 462 | - | 274 | 39 | 209 | 34 | 72 | 313 | 130 | 6 | 937 | 159 | - | 605 | 10 | 602 | 5,376 |
| Renewable - Battery, 8-23 hour | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Battery, 24+ hour | - | - | - | - | - | 191 | 2 | 3 | 3 | 3 | 3 | 3 | 114 | 3 | 3 | 186 | 78 | 233 | 168 | 118 | 4 | 1,115 |
| Other Renewable | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Storage - Other | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | | | | | | | | | | | | | | | | | | |
| **Existing Unit Changes** | | | | | | | | | | | | | | | | | | | | | | |
| Coal Plant Retirements - Minority Own | - | (82) | - | (33) | (123) | (148) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (386) |
| Coal Plant Retirements | - | - | - | (220) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (220) |
| Coal Plant Ceases as Coal | - | (357) | - | - | (205) | (700) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (1,262) |
| Coal - CCS | - | - | - | - | - | 526 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 526 |
| Coal - Gas Conversions | - | 357 | - | - | 205 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 562 |
| 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** | **226** | **2,083** | **743** | **4,116** | **1,401** | **1,217** | **1,032** | **1,325** | **1,230** | **1,129** | **724** | **689** | **443** | **1,447** | **324** | **563** | **1,030** | **406** | **998** | |

# No Coal 2032

**Summary Portfolio Capacity by Resource Type and Year, Installed MW**

| | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** | **2034** | **2035** | **2036** | **2037** | **2038** | **2039** | **2040** | **2041** | **2042** | **2043** | **2044** | **2045** | **Total** |
| **Expansion Options** | | | | | | | | | | | | | | | | | | | | | | |
| Gas - CCCT | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Gas - Peaking | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Nuclear | - | - | - | - | - | - | - | 500 | - | - | - | - | - | - | - | - | - | - | - | - | - | 500 |
| Renewable Peaking | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 19 | - | 4 | - | 18 | 41 |
| DSM - Energy Efficiency | 92 | 89 | 210 | 221 | 231 | 251 | 319 | 304 | 308 | 298 | 309 | 325 | 347 | 314 | 293 | 299 | 304 | 315 | 270 | 246 | 220 | 5,565 |
| DSM - Demand Response | 18 | 2 | - | 63 | 19 | 16 | - | 5 | 1 | 3 | 3 | 19 | 328 | 18 | 5 | 25 | 5 | 146 | 33 | 27 | 51 | 787 |
| Renewable - Wind | - | - | - | 21 | 594 | 2,914 | - | 1 | - | 29 | 347 | 40 | 175 | 37 | - | 376 | 50 | - | 20 | - | 96 | 4,700 |
| Renewable - Small Scale Wind | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Utility Solar | - | - | - | 222 | 180 | 1,690 | 494 | 635 | 545 | 792 | 114 | 100 | 1 | - | 554 | 104 | 12 | - | - | 197 | 75 | 5,715 |
| Renewable - Small Scale Solar | - | - | - | - | - | 320 | 2 | 18 | 26 | 21 | 30 | 132 | - | 309 | - | - | 110 | - | - | 143 | 36 | 1,147 |
| Renewable - Geothermal | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Battery, < 8 hour | - | - | - | 1,145 | 215 | 565 | - | 119 | 39 | 210 | 20 | 47 | - | 175 | 67 | 113 | 67 | 152 | 5 | 416 | 18 | 3,373 |
| Renewable - Battery, 8-23 hour | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Battery, 24+ hour | - | - | - | - | - | 510 | 91 | 3 | 4 | 3 | 4 | 4 | 33 | 83 | 37 | 939 | 107 | 390 | 401 | 197 | 358 | 3,164 |
| Other Renewable | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Storage - Other | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | | | | | | | | | | | | | | | | | | |
| **Existing Unit Changes** | | | | | | | | | | | | | | | | | | | | | | |
| Coal Plant Retirements - Minority Own | - | (82) | - | (33) | (123) | (148) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (386) |
| Coal Plant Retirements | - | - | - | (220) | - | - | - | (686) | - | - | - | - | - | - | - | - | - | - | - | - | - | (906) |
| Coal Plant Ceases as Coal | - | (357) | - | - | (205) | (2,679) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (3,241) |
| Coal - CCS | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Coal - Gas Conversions | - | 357 | - | - | 205 | 2,679 | - | - | - | - | - | - | - | - | - | - | - | - | (156) | - | - | 3,085 |
| 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) | (2) | (52) |
| Expire - Other | - | 520 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (20) | 500 |
| | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | | | | | | | | | | | | | | | | | | |
| **Total** | **110** | **464** | **210** | **1,417** | **1,116** | **6,019** | **697** | **899** | **923** | **1,353** | **827** | **667** | **784** | **904** | **956** | **1,856** | **276** | **1,003** | **530** | **993** | **850** | |

# Offshore Wind

| Summary Portfolio Capacity by Resource Type and Year, Installed MW | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | | |
| Resource | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | Total |
| **Expansion Options** | | | | | | | | | | | | | | | | | | | | | | |
| Gas - CCCT | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Gas - Peaking | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Nuclear | - | - | - | - | - | - | - | 500 | - | - | - | - | - | - | - | - | - | - | - | - | - | 500 |
| Renewable Peaking | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| DSM - Energy Efficiency | 92 | 89 | 209 | 219 | 240 | 260 | 331 | 292 | 306 | 294 | 299 | 322 | 345 | 314 | 310 | 301 | 303 | 314 | 222 | 218 | 182 | 5,462 |
| DSM - Demand Response | 18 | 2 | - | 63 | 20 | 206 | 21 | 8 | - | 10 | 4 | 4 | 110 | 29 | 5 | 11 | 8 | 166 | 30 | 31 | 50 | 796 |
| Renewable - Wind | - | - | 100 | 100 | 762 | 630 | 400 | 1 | 1,000 | 98 | 100 | 100 | - | - | - | 353 | 95 | - | - | - | 162 | 3,901 |
| Renewable - Small Scale Wind | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Utility Solar | - | - | 103 | 237 | 205 | 1,382 | 885 | 249 | 104 | 100 | 100 | 100 | 103 | 392 | 444 | 100 | - | - | - | 116 | 26 | 4,646 |
| Renewable - Small Scale Solar | - | - | - | - | - | 416 | - | - | - | - | - | - | - | 24 | 29 | 114 | 142 | - | 36 | 250 | 26 | 1,037 |
| Renewable - Geothermal | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Battery, < 8 hour | - | - | 7 | 2,291 | 527 | 528 | - | 149 | - | 131 | 46 | 54 | 2 | 251 | 113 | 1,454 | 211 | 675 | 768 | 82 | 834 | 8,123 |
| Renewable - Battery, 8-23 hour | - | - | 1 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 1 |
| Renewable - Battery, 24+ hour | - | - | - | - | - | 1,577 | 20 | 23 | 23 | 22 | 25 | 26 | 24 | 27 | 28 | 127 | 34 | 142 | 96 | 30 | 34 | 2,258 |
| Other Renewable | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Storage - Other | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | | | | | | | | | | | | | | | | | | |
| **Existing Unit Changes** | | | | | | | | | | | | | | | | | | | | | | |
| Coal Plant Retirements - Minority Own | - | (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) | (2) | (52) |
| Expire - Other | - | 520 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (20) | 500 |
| | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | | | | | | | | | | | | | | | | | | |
| **Total** | **110** | **464** | **420** | **2,655** | **1,631** | **4,578** | **1,448** | **1,222** | **1,433** | **652** | **574** | **606** | **484** | **1,005** | **929** | **2,460** | **395** | **1,297** | **423** | **494** | **1,292** | |

# LN (Low Natural Gas / No $CO_2$ Proxy)

**Summary Portfolio Capacity by Resource Type and Year, Installed MW**

| 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 |
| **Expansion Options** | | | | | | | | | | | | | | | | | | | | | | |
| Gas - CCCT | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 496 | 496 |
| Gas - Peaking | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Nuclear | - | - | - | - | - | - | - | 500 | - | - | - | - | - | - | - | - | - | - | - | - | - | 500 |
| Renewable Peaking | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| DSM - Energy Efficiency | 92 | 89 | 207 | 223 | 236 | 257 | 325 | 288 | 300 | 289 | 311 | 318 | 343 | 309 | 322 | 305 | 302 | 291 | 272 | 244 | 217 | 5,540 |
| DSM - Demand Response | 18 | 2 | - | 63 | 19 | 75 | 149 | 7 | 2 | 4 | 4 | 14 | 110 | 14 | 5 | 24 | 124 | - | 8 | 80 | 51 | 773 |
| Renewable - Wind | - | - | - | - | 594 | 1,265 | 594 | 2 | - | 24 | 369 | 1 | 176 | 38 | - | 365 | 90 | - | 3 | - | 150 | 3,671 |
| Renewable - Small Scale Wind | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Utility Solar | - | - | - | 200 | 138 | 1,761 | 517 | 239 | 398 | 230 | 7 | - | 1 | - | 570 | 93 | 61 | - | - | 44 | 110 | 4,369 |
| Renewable - Small Scale Solar | - | - | - | - | - | 320 | 2 | 18 | 26 | 21 | 31 | 153 | - | 306 | - | - | 97 | - | 35 | 101 | 36 | 1,146 |
| Renewable - Geothermal | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Battery, < 8 hour | - | - | - | 1,252 | 220 | 609 | - | 99 | 39 | 209 | 23 | 82 | - | 239 | 67 | 1,126 | 1,060 | - | 272 | 12 | 1,437 | 6,746 |
| Renewable - Battery, 8-23 hour | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Battery, 24+ hour | - | - | - | - | - | 271 | 95 | 4 | 4 | 3 | 4 | 4 | 17 | 38 | 40 | 132 | 26 | 215 | 137 | 159 | 16 | 1,165 |
| Other Renewable | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Storage - Other | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | | | | | | | | | | | | | | | | | | |
| **Existing Unit Changes** | | | | | | | | | | | | | | | | | | | | | | |
| Coal Plant Retirements - Minority Own | - | (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 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 562 |
| 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) | (2) | (52) |
| Expire - Other | - | 520 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (20) | 500 |
| | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | | | | | | | | | | | | | | | | | | |
| **Total** | **110** | **464** | **207** | **1,483** | **1,084** | **4,137** | **1,473** | **1,157** | **769** | **777** | **749** | **572** | **547** | **912** | **1,004** | **2,045** | **1,362** | **(20)** | **680** | **407** | **2,491** | |

# MR (Medium Natural Gas / Current Federal $CO_2$ Regulations)

| Summary Portfolio Capacity by Resource Type and Year, Installed MW | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Resource | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | Total |
| **Expansion Options** | | | | | | | | | | | | | | | | | | | | | | |
| Gas - CCCT | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Gas - Peaking | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Nuclear | - | - | - | - | - | - | - | 500 | - | - | - | - | - | - | - | - | - | - | - | - | - | 500 |
| Renewable Peaking | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 19 | - | 4 | - | 18 | 41 |
| DSM - Energy Efficiency | 92 | 89 | 209 | 221 | 231 | 256 | 329 | 313 | 326 | 315 | 318 | 326 | 369 | 335 | 313 | 308 | 304 | 315 | 254 | 224 | 209 | 5,656 |
| DSM - Demand Response | 18 | 2 | - | 63 | 19 | 16 | 3 | 5 | 1 | 5 | 3 | 19 | 323 | 18 | 5 | 24 | 114 | 34 | 34 | 25 | 205 | 936 |
| Renewable - Wind | - | - | - | 21 | 694 | 1,931 | 200 | 382 | 100 | 129 | 447 | 40 | 175 | 37 | - | 376 | 50 | - | 20 | - | 96 | 4,698 |
| Renewable - Small Scale Wind | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Utility Solar | - | - | - | 222 | 180 | 1,690 | 863 | 934 | 420 | 467 | 213 | 133 | 1 | - | 554 | 104 | 12 | - | - | 197 | 75 | 6,065 |
| Renewable - Small Scale Solar | - | - | - | - | - | 320 | 2 | 18 | 26 | 21 | 30 | 132 | - | 309 | - | - | 110 | - | - | 143 | 36 | 1,147 |
| Renewable - Geothermal | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Battery, < 8 hour | - | - | - | 1,156 | 215 | 438 | - | 119 | 39 | 210 | 20 | 47 | 27 | 175 | 67 | 113 | 582 | 33 | 5 | 305 | 324 | 3,875 |
| Renewable - Battery, 8-23 hour | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Battery, 24+ hour | - | - | - | - | - | 510 | 91 | 3 | 4 | 3 | 4 | 4 | 175 | 83 | 37 | 939 | 107 | 510 | 401 | 197 | 455 | 3,523 |
| Other Renewable | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Storage - Other | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | | | | | | | | | | | | | | | | | | |
| **Existing Unit Changes** | | | | | | | | | | | | | | | | | | | | | | |
| Coal Plant Retirements - Minority Own | - | (82) | - | (33) | (123) | (148) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (386) |
| Coal Plant Retirements | - | - | - | (220) | - | - | - | (686) | - | - | - | - | - | - | - | - | - | - | - | - | - | (906) |
| Coal Plant Ceases as Coal | - | (357) | - | - | (205) | (2,679) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (3,241) |
| Coal - CCS | - | - | - | - | - | 526 | - | - | - | - | - | - | - | - | - | - | - | - | (526) | - | - | 0 |
| Coal - Gas Conversions | - | 357 | - | - | 205 | 1,979 | - | - | - | - | - | - | - | - | - | - | - | - | (156) | - | - | 2,385 |
| 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) | (2) | (52) |
| Expire - Other | - | 520 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (20) | 500 |
| | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | | | | | | | | | | | | | | | | | | |
| **Total** | **110** | **464** | **209** | **1,428** | **1,216** | **4,740** | **1,279** | **1,588** | **916** | **1,147** | **1,035** | **701** | **970** | **925** | **976** | **1,864** | **900** | **892** | **(11)** | **858** | **1,396** | |

# HH (High Natural Gas / High $CO_2$ Proxy)

| Summary Portfolio Capacity by Resource Type and Year, Installed MW | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | | |
| Resource | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | Total |
| **Expansion Options** | | | | | | | | | | | | | | | | | | | | | | |
| Gas - CCCT | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Gas - Peaking | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Nuclear | - | - | - | - | - | - | - | 500 | - | - | - | - | - | - | - | - | - | - | - | - | - | 500 |
| Renewable Peaking | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 19 | - | 4 | - | 18 | 41 |
| DSM - Energy Efficiency | 92 | 89 | 211 | 223 | 237 | 257 | 309 | 295 | 300 | 289 | 309 | 315 | 347 | 326 | 305 | 302 | 305 | 316 | 259 | 252 | 230 | 5,568 |
| DSM - Demand Response | 18 | 2 | - | 63 | 22 | 13 | - | 5 | 1 | 3 | 3 | 19 | - | 18 | 8 | 24 | 5 | 463 | 15 | 157 | 30 | 869 |
| Renewable - Wind | - | - | - | 21 | 794 | 2,712 | - | 42 | - | 29 | 349 | 40 | 175 | 37 | - | 376 | 50 | - | 20 | - | 96 | 4,741 |
| Renewable - Small Scale Wind | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Utility Solar | - | - | - | 222 | 181 | 1,813 | 1,750 | 240 | 457 | 225 | 267 | - | 1 | - | 554 | 104 | 12 | - | - | 197 | 75 | 6,098 |
| Renewable - Small Scale Solar | - | - | - | - | - | 320 | 2 | 18 | 26 | 21 | 30 | 132 | - | 309 | - | - | 110 | - | - | 143 | 36 | 1,147 |
| Renewable - Geothermal | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Battery, < 8 hour | - | - | 2 | 1,146 | 302 | 1,383 | - | 119 | 39 | 210 | 20 | 47 | - | 175 | 67 | 113 | 67 | - | 5 | - | - | 3,695 |
| Renewable - Battery, 8-23 hour | - | - | 1 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 1 |
| Renewable - Battery, 24+ hour | - | - | - | - | - | 511 | 91 | 3 | 4 | 3 | 4 | 4 | 11 | 83 | 37 | 939 | 107 | 641 | 402 | 197 | 598 | 3,635 |
| Other Renewable | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Storage - Other | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | | | | | | | | | | | | | | | | | | |
| **Existing Unit Changes** | | | | | | | | | | | | | | | | | | | | | | |
| Coal Plant Retirements - Minority Own | - | (82) | - | (33) | (123) | (148) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (386) |
| Coal Plant Retirements | - | - | - | (220) | - | - | (268) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (488) |
| Coal Plant Ceases as Coal | - | (357) | - | - | (205) | (1,299) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (1,861) |
| Coal - CCS | - | - | - | - | - | 526 | - | - | - | - | - | - | - | - | - | - | - | - | (526) | - | - | 0 |
| Coal - Gas Conversions | - | 357 | - | - | 205 | 599 | - | - | (269) | - | - | - | - | - | - | - | - | - | - | - | - | 892 |
| 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) | (2) | (52) |
| Expire - Other | - | 520 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (20) | 500 |
| | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | | | | | | | | | | | | | | | | | | |
| **Total** | **110** | **464** | **214** | **1,420** | **1,413** | **6,588** | **1,675** | **1,222** | **558** | **777** | **982** | **557** | **434** | **916** | **971** | **1,858** | **277** | **1,420** | **132** | **713** | **1,061** | |

# SC (Social Cost of Greenhouse Gases)

| Summary Portfolio Capacity by Resource Type and Year, Installed MW | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Resource | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | Total |
| **Expansion Options** | | | | | | | | | | | | | | | | | | | | | | |
| Gas - CCCT | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Gas - Peaking | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Nuclear | - | - | - | - | - | - | - | 500 | - | - | - | - | - | - | - | - | - | - | - | - | - | 500 |
| Renewable Peaking | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| DSM - Energy Efficiency | 92 | 89 | 211 | 226 | 241 | 263 | 329 | 293 | 314 | 305 | 318 | 325 | 357 | 325 | 320 | 308 | 305 | 315 | 270 | 260 | 219 | 5,685 |
| DSM - Demand Response | 18 | 2 | 2 | 64 | 28 | 191 | 14 | 5 | 1 | 1 | 18 | 11 | 108 | 18 | 10 | 24 | 6 | 150 | 12 | 50 | 46 | 779 |
| Renewable - Wind | - | - | - | 20 | 1,614 | 1,353 | 352 | 1 | - | 65 | 293 | 237 | 114 | 26 | 29 | 423 | 47 | - | - | 11 | 196 | 4,781 |
| Renewable - Small Scale Wind | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Utility Solar | - | - | 22 | 381 | 144 | 2,005 | 1,259 | 335 | 400 | 206 | 225 | 90 | 1 | - | 471 | 115 | - | - | - | 288 | 92 | 6,034 |
| Renewable - Small Scale Solar | - | - | - | - | - | 320 | 2 | 19 | 26 | 23 | 24 | 20 | 9 | 312 | - | 42 | 170 | - | - | 56 | 26 | 1,049 |
| Renewable - Geothermal | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Battery, < 8 hour | - | - | - | 2,147 | 329 | 484 | - | 175 | 7 | 194 | 2 | 23 | - | 286 | 121 | 1,095 | 138 | 245 | 192 | 237 | 531 | 6,206 |
| Renewable - Battery, 8-23 hour | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Renewable - Battery, 24+ hour | - | - | - | - | - | 1,410 | 107 | 19 | 19 | 18 | 20 | 21 | 69 | 22 | 34 | 141 | 141 | 442 | 219 | 169 | 94 | 2,945 |
| Other Renewable | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Storage - Other | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | | | | | | | | | | | | | | | | | | |
| **Existing Unit Changes** | | | | | | | | | | | | | | | | | | | | | | |
| Coal Plant Retirements - Minority Own | - | (82) | - | (33) | (123) | (148) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (386) |
| Coal Plant Retirements | - | - | - | (488) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (269) | - | - | (757) |
| Coal Plant Ceases as Coal | - | (357) | - | - | (205) | (1,030) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (1,592) |
| Coal - CCS | - | - | - | - | - | 526 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 526 |
| Coal - Gas Conversions | - | 357 | - | - | 205 | 330 | - | - | - | - | - | - | - | - | - | - | - | - | (99) | - | - | 793 |
| Gas Plant Retirements | - | - | - | (167) | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (167) |
| 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) | (2) | (52) |
| Expire - Other | - | 520 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | (20) | 500 |
| | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | | | | | | | | | | | | | | | | | | |
| **Total** | **110** | **464** | **235** | **2,148** | **2,233** | **5,605** | **1,854** | **1,347** | **767** | **809** | **900** | **727** | **558** | **957** | **985** | **2,148** | **409** | **1,152** | **278** | **838** | **1,182** | |

# APPENDIX K – CAPACITY CONTRIBUTION

## Introduction

The capacity contribution of a resource is represented as a percentage of that resource's nameplate or maximum capacity and is a measure of the ability of a resource to reliably meet demand. This capacity contribution affects PacifiCorp's resource planning activities, which are intended to ensure there is sufficient capacity on its system to meet its load obligations inclusive of a planning reserve margin. Because of the increasing penetration of variable energy resources (such as wind and solar) and energy-limited resources (such as storage and demand response), planning for coincident peak loads is no longer sufficient to determine the necessary amount and timing of new resources. To ensure resource adequacy is maintained over time, all resource portfolios evaluated in the integrated resource plan (IRP) have sufficient capacity to meet PacifiCorp's load obligations and a planning reserve margin in all hours of each year. Because all resources provide both energy and capacity benefits, identifying the resource that can provide additional capacity at the lowest incremental cost to customers is not straightforward. A resource's energy value is dependent on its generation profile and location, as well as the composition of resources and transmission in the overall portfolio. Similarly, a resource's capacity value (or contribution to ensuring reliable system operation) is also dependent on both its characteristics and the composition of the overall portfolio. To further complicate the analysis, PacifiCorp's portfolio composition changes dramatically over time, as a result of retirements and expiring contracts.

In the 2019 IRP, PacifiCorp developed initial capacity contribution estimates for wind and solar capacity that accounted for expected declining contributions as the level of penetration increased. A key assumption in this analysis was that only a single variable was modified, for example, when evaluating solar penetration level, the capacity from wind and energy storage resources in the portfolio were held constant. As the preparation of the 2019 IRP continued, PacifiCorp identified that these initial estimates did not adequately account for the interactions between solar, wind, and energy storage and thus did not ensure that each portfolio was adequately reliable. Therefore, as part of the 2019 IRP PacifiCorp assessed each portfolio to verify that it would support reliable operation in each hour of the year. PacifiCorp has continued to perform this portfolio-wide reliability assessment.

In the past, PacifiCorp's stochastic analysis has reflected standard deviations, mean reversion, and correlation to represent the expected variation in loads, thermal outages, and hydro conditions (along with market prices, which only impact economics, and not loss of load risk). As discussed in Appendix H (Stochastics), for the 2025 IRP PacifiCorp is adding variations in wind and solar generation, and will account for inter-annual variations, rather than relying upon mean reverting variables.

PacifiCorp calculates two kinds of capacity contribution values for different purposes. First, Appendix K (Capacity Contribution) in prior IRPs has reported marginal capacity contribution values which reflect the expected reduction in loss of load events as a result of a small increase in a given resource, with no other changes in a PacifiCorp's portfolio. Second, values based on the Western Resource Adequacy Program (WRAP) methodology are used to measure resource adequacy and are reported in the load and resource balance. The WRAP methodology produces "portfolio" capacity contribution values, or the average contribution from all resources of a given type based on the combined portfolios of WRAP participants, though with some variation to reflect the performance of individual projects. However, the WRAP methodology does not give priority to existing projects relative to new projects, as all projects of a given type receive equivalent treatment.

## CF Methodology

Marginal capacity contribution values are calculated using the capacity factor approximation method (CF Method) as outlined in a 2012 report produced by the National Renewable Energy Laboratory (NREL Report).[1] The CF Method calculates a capacity contribution based on a resource's expected availability during periods when the risk of loss of load events is highest, based on the loss of load probability (LOLP) in each hour. This CF Method analysis is performed using a portfolio that is comparable to the preferred portfolio. For the reasons discussed above, this analysis provides a reasonable estimate of capacity contribution value so long as the changes relative to the preferred portfolio are small, since in effect, the CF Method calculates the marginal capacity contribution of a one megawatt resource addition. Changes to the locations and quantities of wind, solar, and energy storage are key drivers of the marginal capacity contribution results.

The NREL Report summarizes several methods for estimating the capacity value of renewable resources that are broadly categorized into two classes: 1) reliability-based methods that are computationally intensive; and 2) approximation methods that use simplified calculations to approximate reliability-based results. The NREL Report references a study from Milligan and Parsons that evaluated capacity factor approximation methods, which use capacity factor data among varying sets of hours, relative to a more computationally intensive reliability-based metric. As discussed in the NREL Report, the CF Method was found to be the most dependable technique in deriving capacity contribution values that approximate those developed using a reliability-based metric.

As described in the NREL Report, the CF Method "considers the capacity factor of a generator over a subset of periods during which the system faces a high risk of an outage event." When using the CF Method, hourly LOLP is calculated and then weighting factors are obtained by dividing each hour's LOLP by the total LOLP over the period. These weighting factors are then applied to the contemporaneous hourly capacity factors to produce a capacity contribution value.

The weighting factors based on LOLP are defined as:

$$w_i = \frac{LOLP_i}{\sum_{j=1}^{T} LOLP_j}$$

where $w_i$ is the weight in hour $i$, $LOLP_i$ is the LOLP in hour $i$, and $T$ is the number of hours in the study period, which is 8,760 hours for the current study. These weights are then used to calculate the weighted average capacity factor as an approximation of the capacity contribution as:

[1] Madaeni, S. H.; Sioshansi, R.; and Denholm, P. "Comparison of Capacity Value Methods for Photovoltaics in the Western United States." NREL/TP-6A20-54704, Denver, CO: National Renewable Energy Laboratory, July 2012 (NREL Report) at: www.nrel.gov/docs/fy12osti/54704.pdf

$$CV = \sum_{i=1}^{T} w_i C_i,$$

where $C_i$ is the capacity factor of the resource in hour *i*, and *CV* is the weighted capacity value of the resource.

For fixed profile resources, including wind, solar, and energy efficiency, the average LOLP values across all iterations are sufficient, as the output of these resources is the same in each iteration. To determine the capacity contribution of fixed profile resources using the CF Method, PacifiCorp implemented the following three steps:

1. A multi-iteration hourly Monte Carlo simulation of PacifiCorp's system was produced using the Plexos Short-Term (ST) model. Each iteration reflects load, hydro, wind, solar and existing thermal resource conditions from a specified historical year from 2006-2023. The LOLP for each hour in the year is calculated by counting the number of iterations in which system load and/or reserve obligations could not be met with available resources and dividing by the total number of iterations.[2] For example, if in hour 19 on December 22nd there are three iterations with shortfalls out of a total of 50 iterations, then the LOLP for that hour would be 6 percent.[3]

2. Weighting factors were determined based upon the LOLP in each hour divided by the sum of LOLP among all hours within the same summer or winter season. In the example noted above, the sum of LOLP among all winter hours is 58 percent.[4] The weighting factor for hour 19 on December 22nd would be 1.0417 percent.[5] This means that 1.0417 percent of all winter loss of load events occurred in hour 19 on December 22nd and that a resource delivering in only that single hour would have a winter capacity contribution of 1.0417 percent.

3. The hourly weighting factors are then applied to the capacity factors of fixed profile resources in the corresponding hours to determine the weighted capacity contribution value in those hours. Extending the example noted, if a resource has a capacity factor of 41.0 percent in hour 19 on December 22nd, its weighted winter capacity contribution for that hour would be 0.4271 percent.[6]

For resources which are energy limited, such as energy storage or demand response programs, the LOLP values in each iteration must be examined independently, to ensure that the available storage or control hours are sufficient. Continuing the example of December 22nd described above,

[2] While PacifiCorp participates in the Northwest Power Pool (NWPP) reserve sharing agreement, this only provides energy from other participants within the first hour of a contingency event, e.g., a forced outage of a generator or transmission line. Shortfalls in the 2023 IRP are much more likely to result from changes in load, renewable resource output, or energy storage limitations, which do not qualify as contingency events. In light of this, PacifiCorp's analysis includes the first hour of every shortfall event.

[3] 0.6 percent = 3 / 500.

[4] For each hour, the hourly LOLP is calculated as the number of iterations with ENS divided by the total of 500 iterations. There are 288 winter ENS iteration-hours out of total of 5,832 winter hours. As a result, the sum of LOLP for the winter is 288 / 500 = 58 percent. There are 579 summer ENS iteration-hours out of total of 2,928 summer hours. As a result, the sum of LOLP for the summer is 579 / 500 = 116 percent.

[5] 1.0417 percent = 0.6 percent / 58 percent, or simply 1.0417 percent = 3 / 288.

[6] 0.4271 percent = 1.0417 percent x 41.0 percent.

consider if hour 18 and hour 19 both have three hours with energy or reserve shortfalls out of 500 iterations. If all six shortfall hours are in different iterations, a 1-hour energy storage resource could cover all six hours. However, if the six shortfall hours are in the same three iterations in hour 18 and hour 19 (i.e. 2-hour duration events), then a 1-hour storage resource could only cover three of the six shortfall hours. Additional considerations are also necessary for hybrid resources which share an interconnection and cannot generate their maximum potential output simultaneously.

The details of the wind and solar resource modeling in the study period are an important aspect of the results. For the 2025 IRP, PacifiCorp is using generation profiles for existing wind and solar and proxy options based on the time period 2006-2023. For each iteration, load, hydro, and existing thermal resource conditions are developed from the same time period. Using historical conditions for as many variables as possible maintains the correlation between the variables as well as the distribution of the results. As one would expect, days with higher load or lower renewable resource generation are more likely to result in shortfall events. By drawing conditions over an entire year, sustained conditions like droughts and under-supply of renewables can be identified, and longer-duration storage may be necessary to avoid loss of load events under those conditions. Given the increasing complexity of the iteration data, basing CF Method capacity contribution calculations on an average or 12-month by 24-hour forecast of renewable generation will tend to overstate capacity contribution, particularly if there is a significant quantity of similarly located resources of the same type already in the portfolio, or if an appreciable quantity of resource additions is being contemplated. Even if an hourly renewable generation forecast is used, capacity contributions can be overstated if the weather underlying the forecast is not consistent with that used for similarly located resources used to develop the CF Method results. Because similarly located resources of the same type would experience similar weather in actual operations, a mismatch in the underlying weather conditions used in renewable generation forecasting will create diversity in the generation supply than would not occur in actual operations.

## CF Method Results

The CF Method results presented in Figure K.1 provide a reasonable capacity contribution value so long as the changes relative to the preferred portfolio are small, since in effect, the CF Method calculates the marginal capacity contribution of a one-megawatt resource addition. Please note that marginal capacity contribution values reported herein are applicable to small incremental or decremental changes relative to the composition of the IRP preferred portfolio and do not represent the average capacity contribution for each of the megawatts of a given resource type included in the preferred portfolio. Nor do these values match what is used in the load and resource balance and discussed later on in the WRAP Methodology and WRAP Results sections of this Appendix. In general, wind, solar, and energy storage have declining marginal capacity contribution values as the quantity of a given resource type increases. This results in average capacity contribution values that exceed the marginal capacity contribution values reported here.

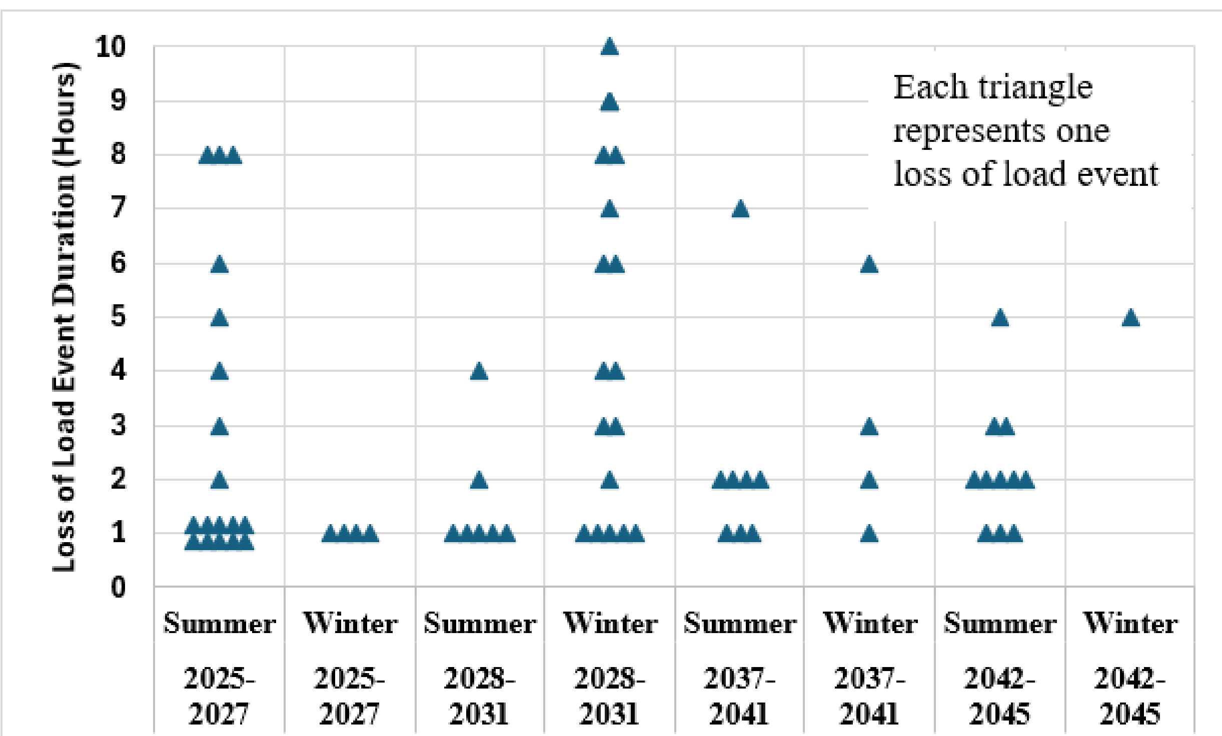
Values presented in Figure K.1 are based on the stochastic results used to develop the risk adjustment for the preferred portfolio, specifically the loss of load events identified as part of that analysis. Values have been aggregated for groups of years due to the limited frequency of events in this data set, which spans 18 conditions (weather years for 2006-2023). The events vary across the horizon, and the preferred portfolio did not experience any loss of events during 2032-2036.

The capacity contribution of solar is relatively low at the start of the horizon but increases in the summer as the portfolio becomes more dependent on energy storage. Because of its reduced output during the winter season, the CF Method contribution of solar in the winter ends up close to zero, though solar is still likely providing reliability benefits for the portfolio as a whole. The capacity contribution of wind varies somewhat over time, particularly on the west, where large amounts of wind as wind resources are a relatively small portion of the resource mix on the west today. The contribution of offshore wind is relatively high, in keeping with its high capacity factor and diverse generation profile relative to onshore wind locations. The capacity contribution of energy storage is limited based on the duration of the event, and the duration of the storage resource. Most loss of load events start in the late afternoon or evening, and the longest loss of load event in this data set was ten hours. Detail on loss of load events is presented in Figure K.2.

**Figure K.1 – CF Method Capacity Contribution Values for Wind, Solar, and Storage**

| | | Solar | | Wind | | | Storage | | | Seasonal |
|---|---|---|---|---|---|---|---|---|---|---|
| **Period** | **Season** | **East** | **West** | **East** | **West** | **Offshore** | **2 Hour** | **4 Hour** | **8 Hour** | **Weight** |
| | **Summer** | 4.7% | 6.0% | 22.5% | 40.0% | 65.3% | 48.1% | 72.2% | 100.0% | 88% |
| **2025-2027** | **Winter** | 3.6% | 4.4% | 38.1% | 19.5% | 38.9% | 100.0% | 100.0% | 100.0% | 12% |
| | **Annual** | **4.6%** | **5.8%** | **24.5%** | **37.5%** | **62.0%** | **51.7%** | **74.1%** | **100.0%** | |
| | **Summer** | 18.1% | 15.2% | 31.0% | 14.0% | 47.7% | 81.8% | 100.0% | 100.0% | 35% |
| **2028-2031** | **Winter** | 0.5% | 0.0% | 27.1% | 6.8% | 54.6% | 35.5% | 61.3% | 94.6% | 65% |
| | **Annual** | **6.7%** | **5.4%** | **28.4%** | **9.4%** | **52.2%** | **40.4%** | **65.4%** | **95.2%** | |
| | **Summer** | 13.9% | 15.8% | 35.4% | 18.5% | 66.8% | 72.2% | 83.3% | 100.0% | 51% |
| **2037-2041** | **Winter** | 0.6% | 0.0% | 2.1% | 1.8% | 1.8% | 58.3% | 83.3% | 100.0% | 49% |
| | **Annual** | **7.4%** | **8.1%** | **19.2%** | **10.4%** | **35.2%** | **66.7%** | **83.3%** | **100.0%** | |
| | **Summer** | 16.7% | 25.7% | 28.0% | 44.4% | 78.1% | 79.2% | 95.8% | 100.0% | 94% |
| **2042-2045** | **Winter** | 1.7% | 0.0% | 13.2% | 90.4% | 60.4% | 40.0% | 80.0% | 100.0% | 6% |
| | **Annual** | **15.7%** | **24.1%** | **27.1%** | **47.2%** | **77.0%** | **72.4%** | **93.1%** | **100.0%** | |

**Figure K.2 – Loss of Load Event Detail**



## WRAP Methodology

The capacity benefits of wind, solar, and storage decline as their share of a portfolio increases, though this effect can be offset some degree as wind, solar, and storage in combination may provide more capacity than they each would provide on their own. But even the combined effect will exhibit diminishing benefits as penetration levels increase. Because WRAP has a wide footprint, the diversity among geographically dispersed wind and solar resources can result in a higher capacity contribution and dilute the impact of resource additions of a given type.

## WRAP Results

Participants in WRAP must register their resources and will then be assigned a Qualifying Capacity Contribution (QCC) that can be counted toward meeting their load requirements. The QCC values are calculated by or on behalf of the WRAP, with methodologies that vary by type, as described in WRAP Business Practice Manual 105 (Qualifying Resources).[7] The current resource types include:

- Thermal or long-duration storage
- Variable energy resources (wind and solar)
- Energy storage
- Hybrid facilities
- Demand response
- Hydro resources (storage and run of river)

In general, WRAP QCC values reflect Effective Load Carrying Capability (ELCC). For thermal and long-duration storage, QCC values are based on a resource's historical forced outage rate during capacity critical hours (the top five percent of hours based on load net of wind, solar, and run of river hydro). These resources are assumed to have random outages, and because they can operate throughout any outage event, their contributions are not impacted if their share of the portfolio goes up or down. As a result, QCC values for thermal and long-duration storage do not require portfolio ELCC analysis. Storage hydro resources have somewhat more involved calculations, accounting for operational limitations and non-power constraints, but generally follow the same treatment as thermal and long-duration storage, based on their potential for maximizing output during capacity critical hours. For wind, solar, run of river hydro, and short-duration energy storage (under eight hours at present), ELCC analysis must account for the share of these resources in the portfolio, as it is impacted by the magnitude of each type as well as interactions among the different types.

[7] WRAP Business Practice Manual 105 Qualifying Resources. Version 1.0. Accessed 11/8/2024: https://www.westernpowerpool.org/private-media/documents/V1.0_BPM_105_Forward_Showing_Qualifying_Resources_12-07-2023.pdf

The WRAP ELCC analysis has several stages and starts by identifying the QCC values for each resource type and location, with results for each forward showing month in the summer (June-September) and winter seasons (November-March). Each individual resource receives a share of the monthly total QCC for their type and location, based on the ratio of their output during capacity critical hours to the total output for all resources of their type and location.

The WRAP ELCC analysis is repeated each year, one year in advance of the forward showing deadline, as detailed in WRAP Business Practice Manual 101 (Advance Assessment).[8] For example, studies would be completed in October 2023 for the summer 2025 season, as the forward showing deadline for the summer of 2025 would be October of 2024.[9] Similarly, the studies for the winter season would be completed in March 2024 for the winter season starting in November 2025.[10]

The recent WRAP ELCC analysis has also included projections of the impacts of increasing wind, solar, and energy storage resource additions on QCC values. Because these values are based on the resource mix of the WRAP regions, and not PacifiCorp's specific portfolio, the 2025 IRP includes a projection of the decline in QCC values over time that is based on the forecast of regional resource changes underlying the September 2024 official forward price curve. As a result, the forecast is independent of PacifiCorp's portfolio selection. Figure K.3 through Figure K.5 show the 2025 WRAP QCC values for solar, wind, and storage, and the Company's projection through the end of the IRP study horizon.

[8] WRAP Business Practice Manual 101 Advance Assessment. Version 1.0. Accessed 11/8/2024: https://www.westernpowerpool.org/private-media/documents/V1.0_BPM_101_Advance_Assessment_12-07-2023.pdf

[9] WRAP Summer 2025 Data. Accessed 11/8/2024: https://www.westernpowerpool.org/private-media/documents/2024-01-31_Webinar_Summer_2025_and_2028_Data.pdf

[10] WRAP Winter 2025-2026 Data. Accessed 11/8/2024: https://www.westernpowerpool.org/private-media/documents/2024-06-13_Webinar_Winter_2025-2026_and_2028-2029_Data.pdf

**Figure K.3 – WRAP Contributions Through Time – Solar**

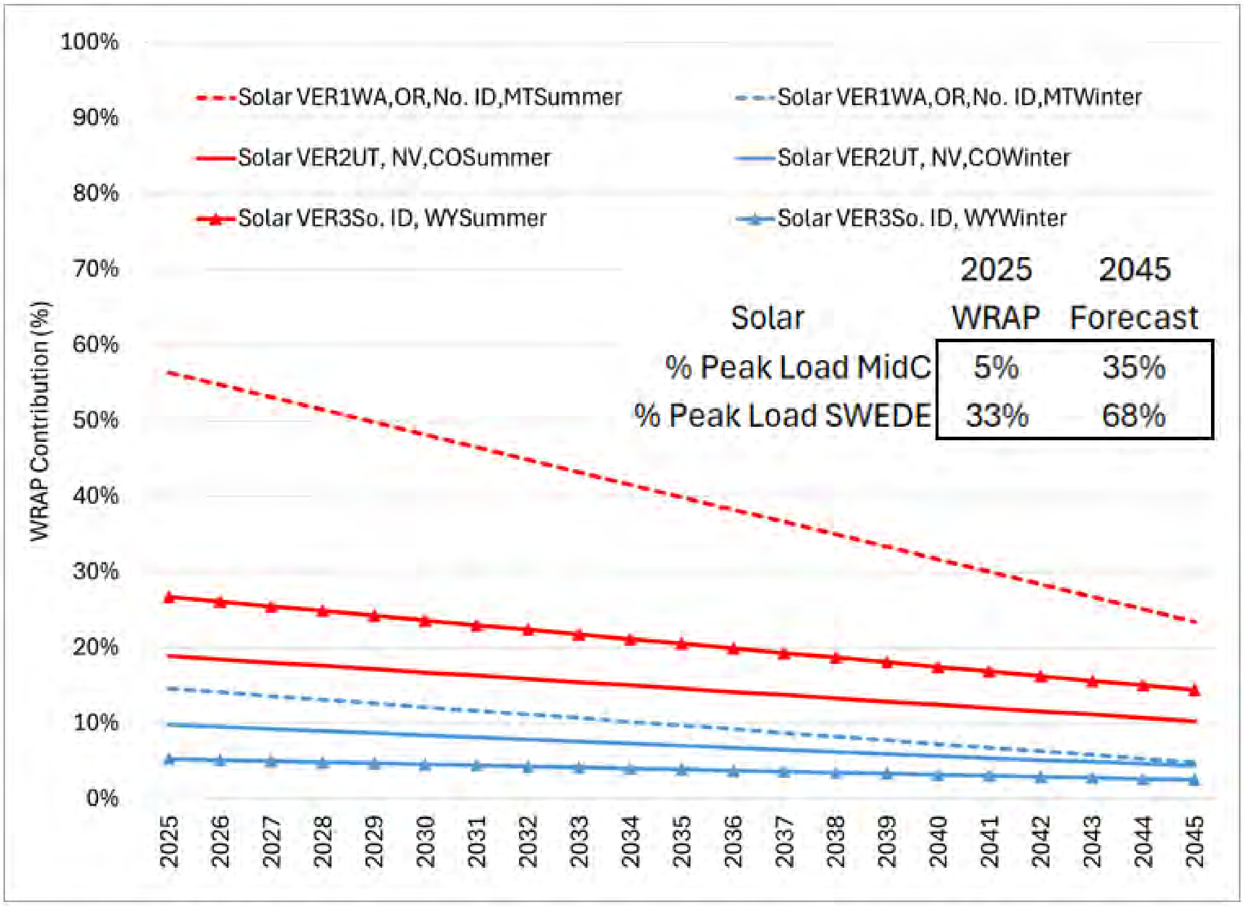


**Figure K.4 – WRAP Contributions Through Time – Wind**

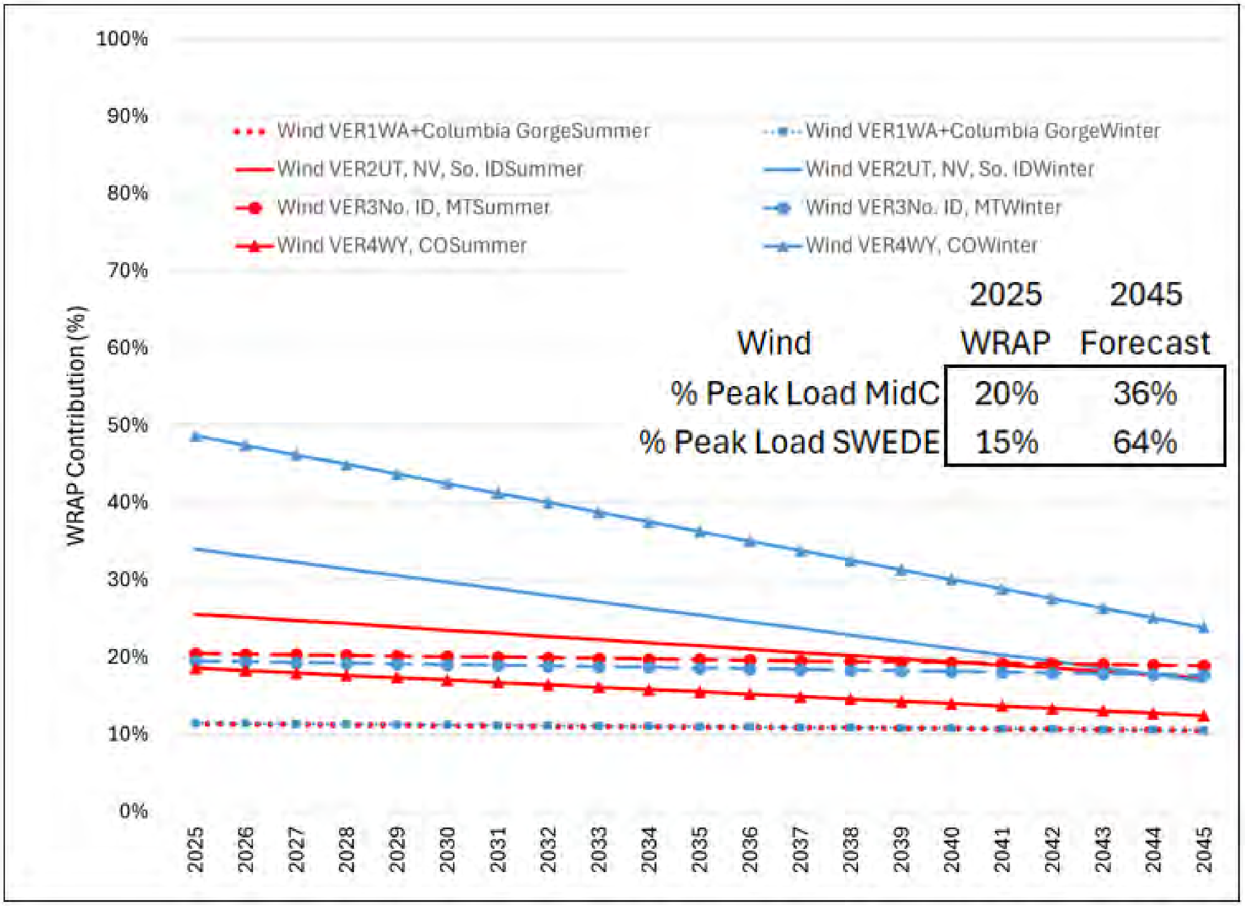
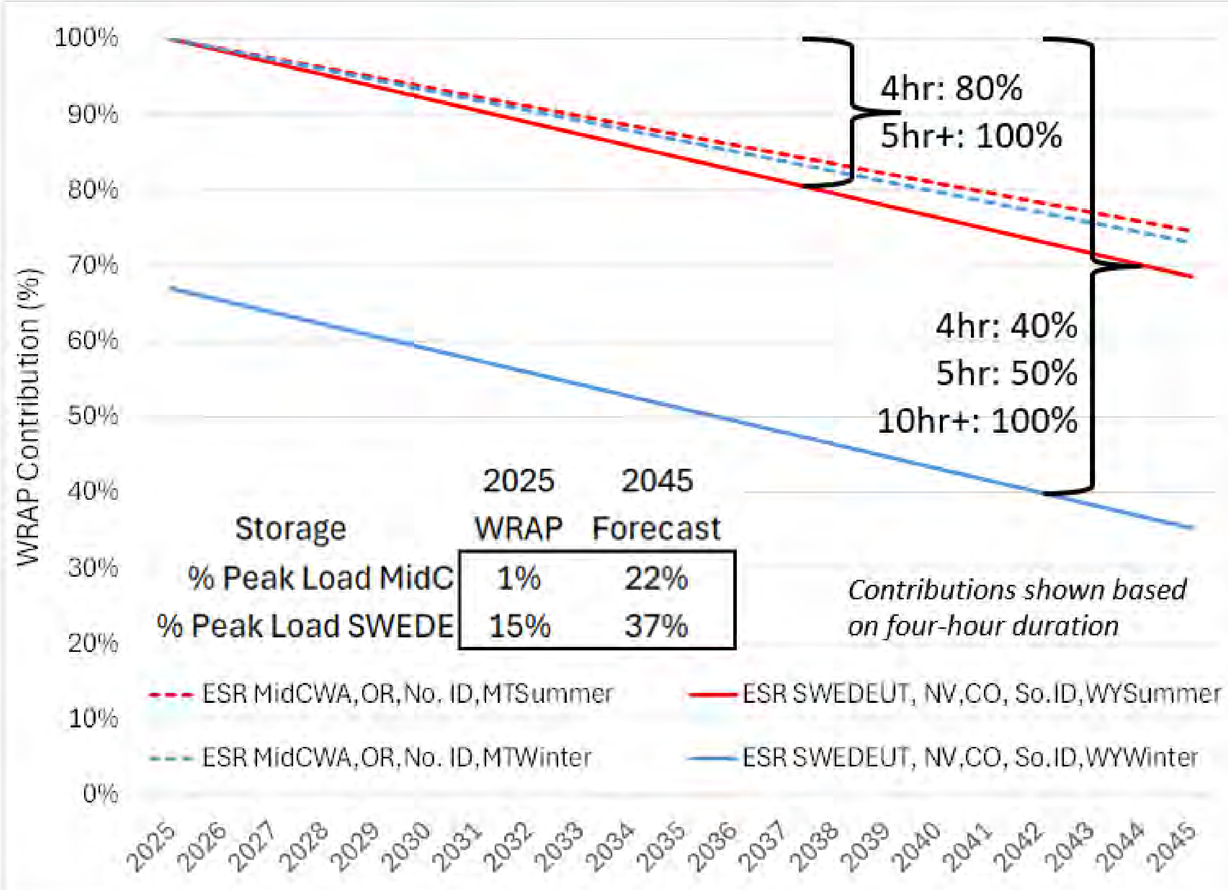


**Figure K.5 – WRAP Contributions Through Time – Storage**



# APPENDIX L – DISTRIBUTED GENERATION STUDY

## Introduction

DNV prepared the Distributed Generation Study for PacifiCorp.[1] A key objective of this research is to assist PacifiCorp in developing penetration forecasts of non-utility owned distributed generation resources to support its 2025 Integrated Resource Plan. The purpose of this study is to project the level of distributed generation resources PacifiCorp's customers might install over the next twenty years under low, base, and high penetration scenarios.

[1] Note that in the 2023 IRP, this study was referred to as the "Private Generation" assessment.

DISTRIBUTED GENERATION FORECAST

# Behind-The-Meter Resource Assessment

PacifiCorp

**Date:** November 25, 2024

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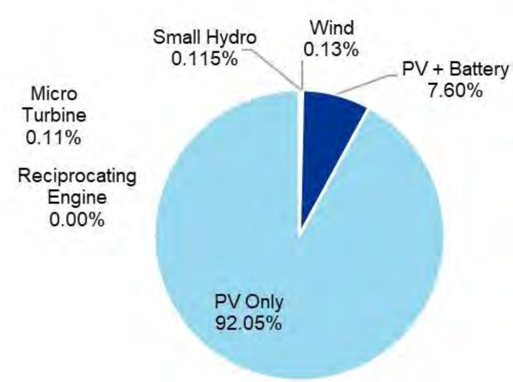
# 1 EXECUTIVE SUMMARY

This report presents DNV's Long-Term Distributed Generation Resource Assessment for PacifiCorp (the Company) covering service territories in Utah, Oregon, Idaho, Wyoming, California, and Washington to support PacifiCorp's 2025 Integrated Resource Plan (IRP). This assessment evaluated the expected adoption of behind-the-meter (BTM) distributed energy resources (DERs) including photovoltaic solar (PV only), photovoltaic solar coupled with battery storage (PV + Battery), small wind, small hydro, reciprocating engines, and microturbines over a 20-year forecast horizon (2024-2043) for all customer sectors (residential, commercial, industrial, and agricultural). The adoption model DNV developed for this study is calibrated to the currently[1] installed and interconnected capacity of these technologies, shown in Figure 1-1.

**Figure 1-1. Historic cumulative installed distributed generation capacity, PacifiCorp, 2014-2024**

**Cumulative installed PG capacity by state**


**Cumulative installed PG capacity by technology**




To date and consistent with the 2023 report, the majority of PG-installed capacity and annual capacity growth has been in Utah, which represents the largest portion of PacifiCorp's customer population—about 50% of all PacifiCorp customers are in the Company's Utah service territory. Roughly 99% of existing distributed generation capacity installed in PacifiCorp's service territory is PV or PV + Battery. To inform the adoption forecast process, DNV conducted an in-depth review of the other technologies and did not find any literature to suggest that they would take on a larger share of the distributed generation market in the Company's service territory in the future years of this study.

DNV developed its assumptions, inputs, methodologies, and forecasts independently from prior distributed generation assessments performed for PacifiCorp. Further, DNV developed three adoption scenarios for each technology and sector: a base case, a high case, and a low case. The base case is considered the most likely projection as it is based on current market trends and expected changes in technology costs and retail electricity rates; the high and low cases are used as sensitivities to test how changes in costs and retail rates impact customer adoption of these technologies. Additional factors considered in the scenarios include export rate factors, value of backup power, incentive levels, and non-monetary market barriers.

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[1] PacifiCorp Distributed Generation interconnection data as of end of quarter 1 2024.

All scenarios use technology cost and performance assumptions specific to each state in PacifiCorp's service territory in the base year (2023) of the assessment. The base case uses the 2023 federal income tax credit schedules and state incentives, retail electricity rate escalation from the Annual Energy Outlook (AEO)[2] reference case, and a blended version of the National Renewable Energy Laboratory (NREL) Annual Technology Baseline[3] moderate and conservative technology cost forecasts as inputs to the modelling process. In the high case, retail electricity rates increase more rapidly, and technology costs decline at a faster rate compared to the base case. The high case also considers NREL's value of backup power in the customer's benefit-cost calculation and a reduction in non-monetary market barriers resulting from the federal efforts to promote distributed generation through the Inflation Reduction Act (IRA) of 2022, further increasing the adoption rates. For the low case, retail electricity rates increase at a slower rate than the base case and technology costs decrease at a slower rate than the base case.

## 1.1 Study methodologies and approaches

The forecasting methodologies and techniques DNV applied in this analysis are commonly used in small-scale, BTM energy resource and energy efficiency forecasting. The methods used to develop the state and sector-level results are described in more detail below.

### 1.1.1 State-level forecast approach

DNV developed a BTM net economic framework that defines costs as the acquisition and installation expenses for each technology, adjusted for available incentives. Benefits are defined as the customer's economic gains from ownership, including energy and demand savings, as well as export credits. We assumed that the current net metering or net billing policies and tariff structures in each state remained the same throughout the assessment. This resulted in the model incorporating benefits associated with net metering in Oregon, Washington, and Wyoming and net billing in Utah and California. We assumed customers in Idaho would accrue benefits based on Utah's net billing policy.

This analysis incorporated the current rate structures and tariffs offered to customers in PacifiCorp's service territories. Time-of-use rates, tiered tariffs, and retail tariffs that include high demand charges increased the value of PV + Battery configurations compared to PV-Only configurations while other factors such as load profiles and DER compensation mechanisms minimized the impact of such tariffs on the customer economics of PV + Battery systems. The DER compensation mechanism in Oregon, Washington, and Wyoming — traditional net metering — does not incentivize PV + Battery storage co-adoption. In net metering DER compensation schemes, customers receive export credits for excess PV generation at the same dollar-per-kWh rate that they would have otherwise paid to purchase electricity from the grid. Net billing—the mechanism modelled in California, Idaho, and Utah—does incentivize PV + Battery storage co-adoption, as customers can lower their electricity bills by charging their batteries with excess PV generation and dispatching their batteries to meet on-site load during times of day when retail energy prices are high. From the perspective of utility bill savings alone, PV + battery systems are often not the most cost-effective option for most customers. Customers who seek the reassurance and reliability of backup power show more of a willingness to pay for this product, especially if they reside in areas prone to outages and severe weather events.

The economic analysis calculated payback by year for each technology by sector and state. A corresponding technical feasibility analysis determined the maximum, feasible adoption for each technology by sector given system size limits,

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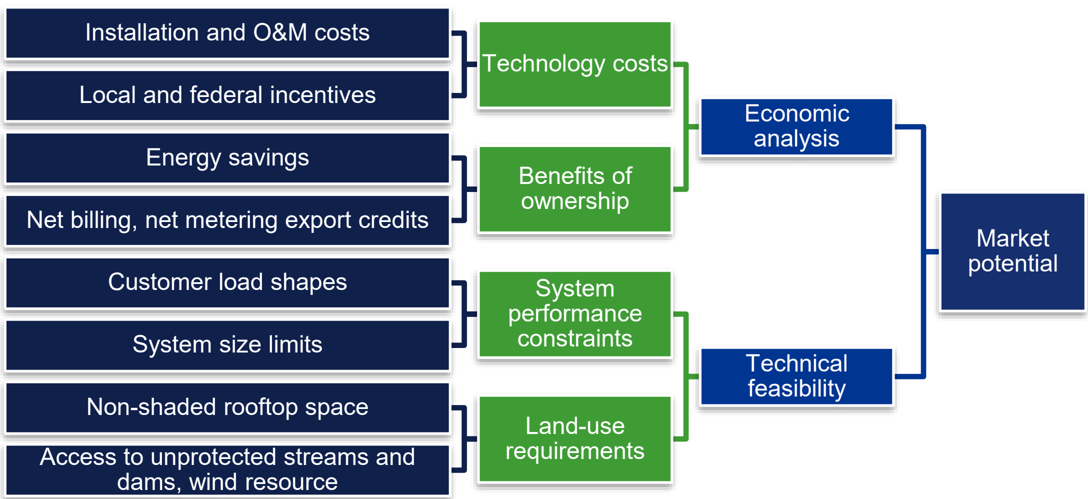
[2] U.S. Energy Information Administration, Annual Energy Outlook 2023 (AEO2023), (Washington, DC, March 2023).

[3] NREL. 2023 Annual Technology Baseline. Golden, CO: National Renewable Energy Laboratory.

customer usage profiles, and physical conditions. The results of the technical feasibility assessment and economic analysis were then used to inform the market adoption analysis to derive market potential. The methodology and major inputs to the analysis are shown in Figure 1-2. Changes to technology costs, retail electricity rates, and federal tax credits used in the high and low cases impact the economic portion of the analysis.

**Figure 1-2. Methodology to determine market potential of distributed generation adoption**



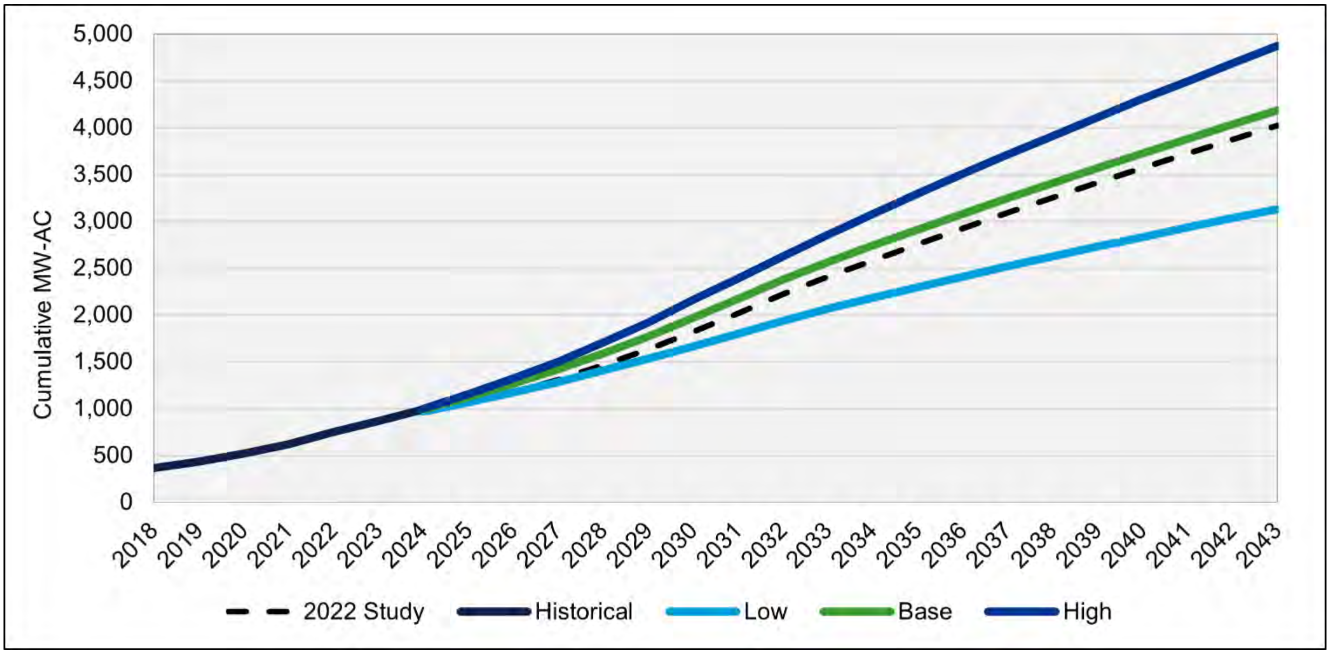

DNV used technology and sector-specific Bass diffusion curves to model market adoption and derive total market potential. Bass diffusion curves are widely used for forecasting technology adoption. Diffusion curves typically take the form of an S-curve with an initial period of slow early adoption that increases as the technology becomes more mainstream and eventually tapers off amongst late adopters. The upper limit of the curve is set to maximum market potential, or the maximum share of the market that will adopt the technology regardless of the interventions applied to influence adoption. In this analysis, the long-term maximum level of market adoption was based on payback. As payback was calculated by year in the economic analysis to capture the changing effects of market interventions over time, the maximum level of market adoption in the diffusion curves varied by year in the study.

The Bass diffusion curves used in the market potential analysis are characterized by three parameters—an innovation coefficient, an imitation coefficient, and the ultimate market potential. Together, these three parameters also determine the time to reach maximum adoption and the overall shape of the curve. The innovation and imitation parameters were calibrated for each technology and sector, based on current market penetration and when PacifiCorp started to see the technology being adopted in each of its service territories. Updated diffusion parameters used the most recent installation data provided by PacifiCorp (through Q1 2024).

## 1.2 Distributed generation forecast

In the base case scenario, DNV estimates 4,182 MW of new distributed generation capacity will be installed in PacifiCorp's service territory over the next twenty years (2024-2043). Figure 1-3 shows historical distributed generation capacity and forecast base, low and high case scenarios compared to the previous (2022) study's total base case forecast. The 2022 study base case scenario estimated 3,874 MW of new capacity over the 20-year forecast. The 2024 study low case scenario estimates 3,129 MW of new capacity over the 20-year forecast while the high case estimates 4,871 MW of new distributed generation capacity installed by 2043.

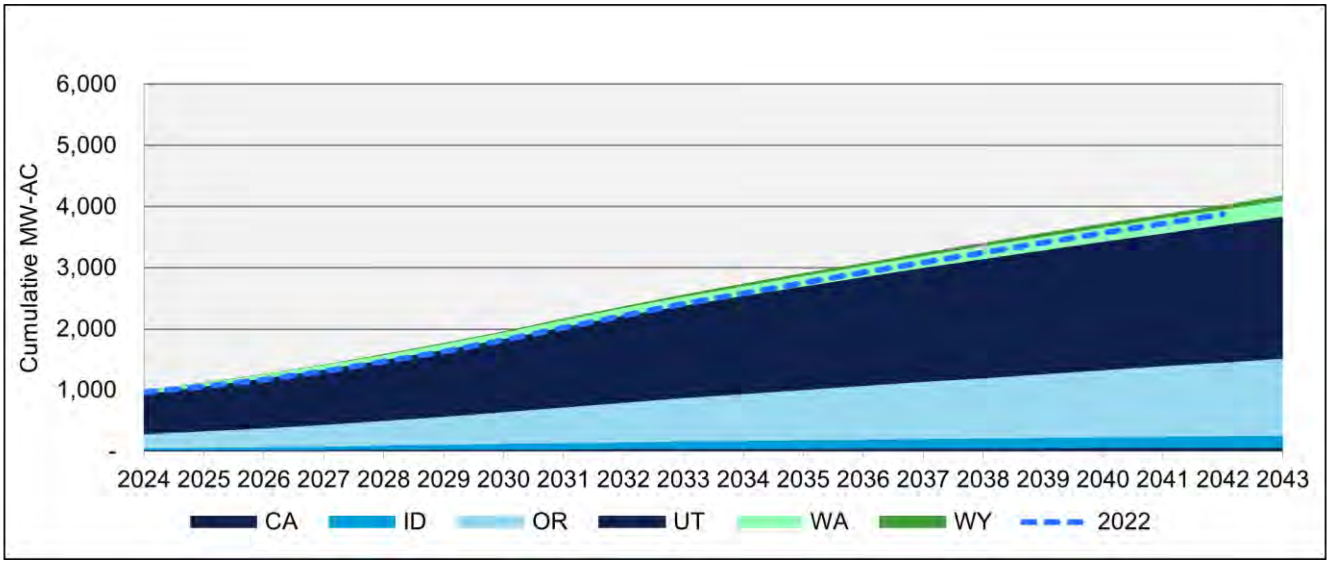
**Figure 1-3. Cumulative historical and new capacity installed by scenario (MW-AC), 2024-2043**




The sensitivity analysis showed a greater margin of uncertainty on the low side than on the high side. The IRA extends tax credits for distributed generation that create favorable economics for adoption, and those are embedded in the base case. We therefore limited our upper bound forecast to lower technology costs and higher retail electricity rates, and these produced only a small boost to adoption for technologies that were already cost-effective under the IRA. In contrast, when we modelled our lower bound, we found that the decreases in cost-effectiveness were enough to tamp down adoption by a wider margin. The low case assumed higher technology costs and lower increases in retail electricity rates than the other cases, reducing the economic appeal of distributed generation despite incentives being unchanged. The low-case forecast is 26% less than the base case, while the high-case cumulative installed capacity forecasted over the 20-year period is 15% greater than the base case.

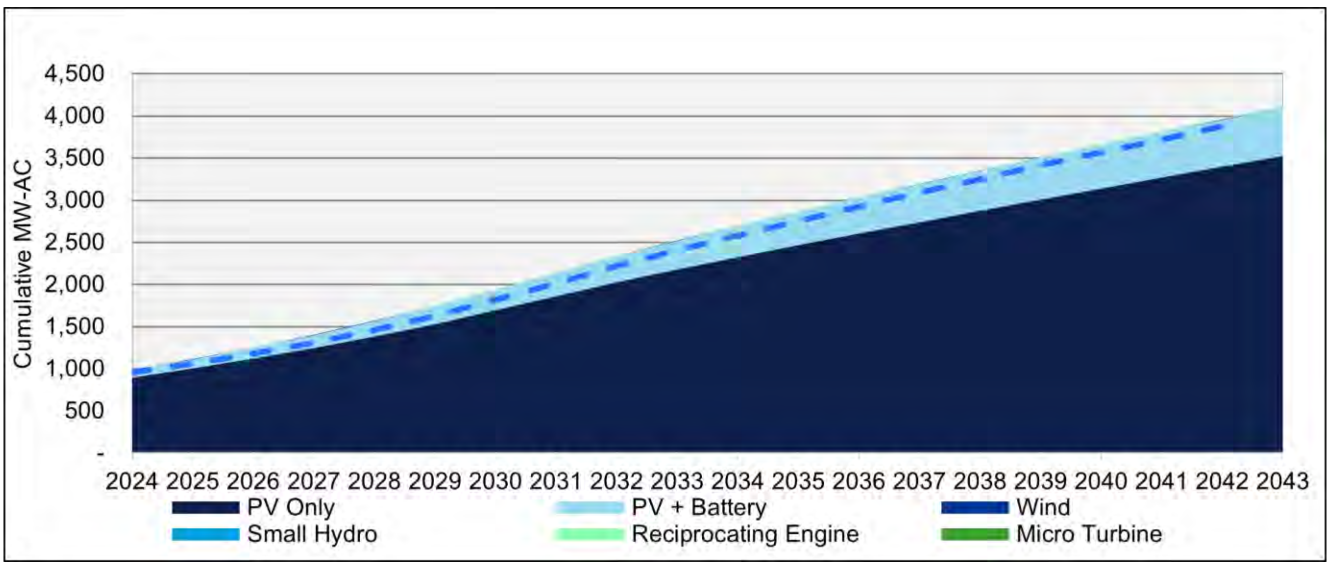
Figure 1-4 shows the base case forecast by state, compared to the previous (2022) assessment's total base case forecast. This figure indicates that Utah and Oregon will drive most PG installations over the next two decades, which is to be expected given these two states represent the largest share of PacifiCorp's customers and sales. Utah continues to dominate near- and long-term adoption (customer base and current adoption levels). Oregon adoption increases significantly in the near- to medium-term due to various factors, and Idaho and Washington experience moderate to high adoption levels over time. The base scenario estimates approximately 1,740 MW of new capacity will be installed over the next 10 years in PacifiCorp's territory—62% of which is in Utah, 36% in Oregon, 8% in Washington, and 5% in Idaho. Given recent adoption trends, projected PV capacity is expected to grow at a faster rate in the early years and at a slower rate towards the end of the forecast period. The key drivers of these differences include larger average PV system sizes, a steeper decline in PV + Battery costs at the start of the forecast period, and the maturity of rooftop PV technology.

Figure 1-4. Cumulative new capacity installed by state (MW-AC), 2024-2043, base case




In Figure 1-5 below, the base case forecast is presented by technology for all states in PacifiCorp's service territory. First-year PV Only is estimated to grow by 10 MW and PV + Battery by 3 MW. These two technologies make up 99% of new installed distributed generation capacity forecasted. The results section of the report contains results by technology for the high, base, and low sectors. Additionally, the total PV capacity forecasted is presented by sector in that section.

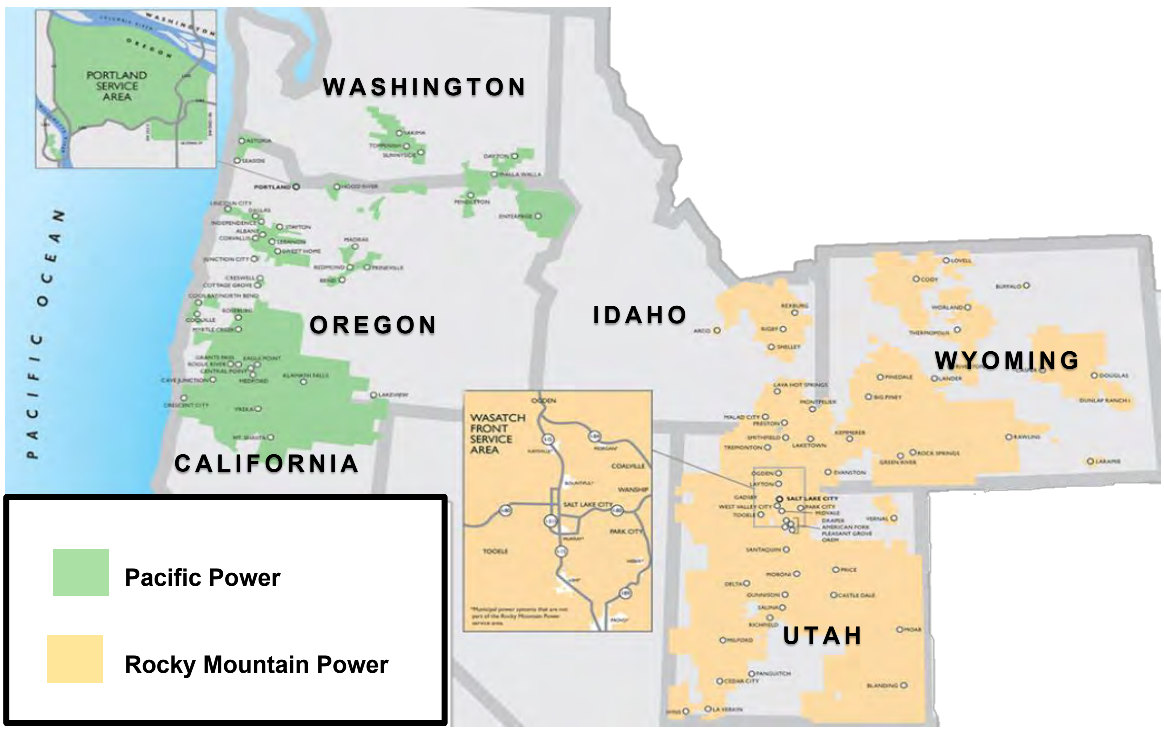
**Figure 1-5. Cumulative new capacity installed by technology (MW-AC), 2024-2043, base case**



## 2 BACKGROUND

DNV prepared this distributed generation Long-term Resource Assessment on behalf of PacifiCorp. The assessment represents their service territory in six states: California, Idaho, Oregon, Utah, Washington, and Wyoming, as shown in Figure 2-1. In this assessment, distributed generation technologies provide BTM energy generation at the customer site and are designed to offset customer load and/or peak demand. This assessment supports PacifiCorp's 2025 IRP forecasting the level of distributed generation resources PacifiCorp's customers may install over the next two decades under base, low, and high adoption scenarios. In addition to distributed generation, DNV also considered the cost-effective potential for high-efficiency cogeneration in Washington, consistent with the 480-109-060 (13) and 480-109-100 (6) of the Washington Administrative Code (WAC).

**Figure 2-1. PacifiCorp service territory**




There have been seven previous assessments involving distributed generation. DNV developed its assumptions, inputs, methodologies, and forecasts for years 2022 and 2024 independently from the prior seven assessments. The forecasting methodologies and techniques DNV applied in this analysis are commonly used in small-scale, BTM energy resource and energy efficiency forecasting. This study evaluated the expected adoption of BTM technologies over the next 20 years, including:

1. Photovoltaic (Solar PV) Systems
2. Solar PV paired with battery storage
3. Small scale wind
4. Small scale hydro
5. Reciprocating engines
6. Microturbines

Project sizes were determined based on average customer load across the commercial, irrigation, industrial, and residential customer classes for each state. The project sizes were then limited by each state's respective system size limits. Distributed generation adoption for each technology was estimated by sector in each state in PacifiCorp's service territory.

# 3 APPROACH AND METHODS

DNV used applicability, technical feasibility, customer perspectives toward distributed generation, and project economics to forecast the expected market adoption of each distributed generation technology.

## 3.1 Technology attributes

The technology attributes define the reference systems and their key attributes such as capacity factors, derate factors, and costs which are used in the payback and adoption analyses. A full list of detailed technology attributes and assumptions by state and sector is provided in section 5. The following information provides a high-level summary of the key elements of the technologies assessed in this analysis.

### 3.1.1 Solar PV

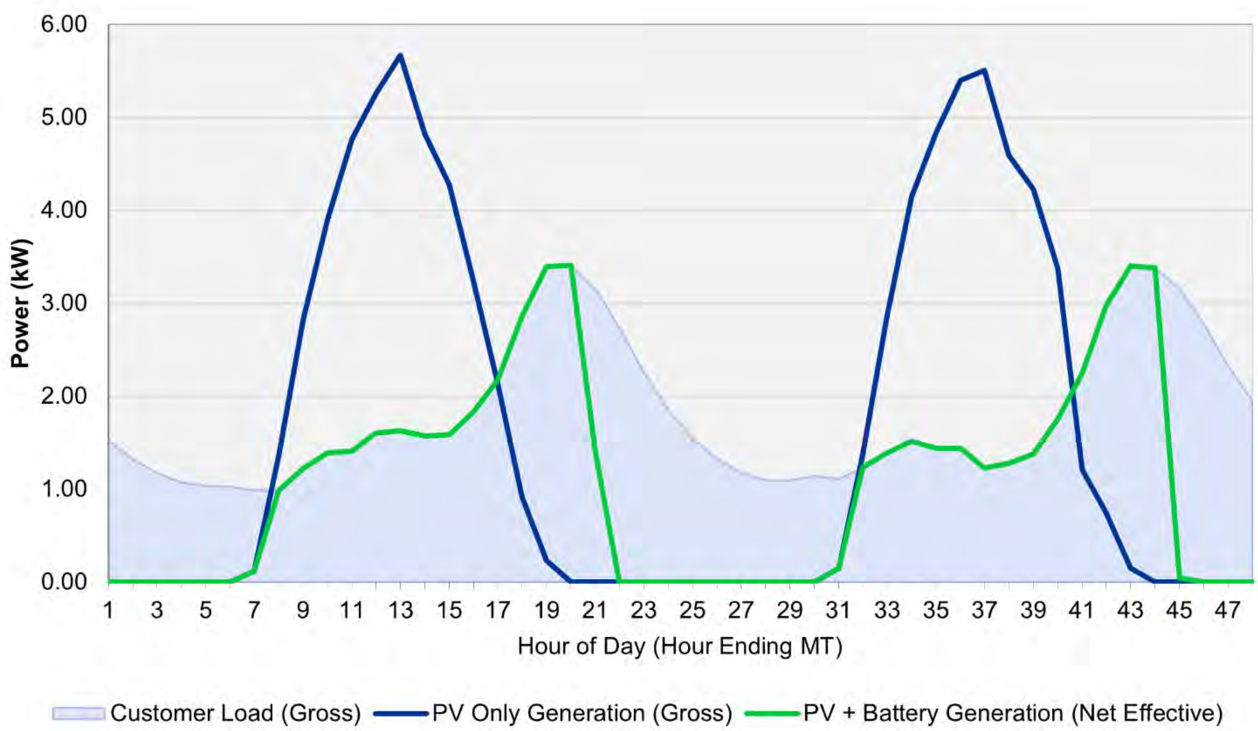
Solar photovoltaic (PV) systems convert sunlight into electrical energy. DNV modeled representative PV system energy output for residential and non-residential systems in each state to estimate first-year production. To model hourly production, DNV leveraged its SolarFarmer and Solar Resource Compass APIs. DNV's Solar Resource Compass API accesses and compares irradiance data from multiple data providers in each region. Solar Resource Compass also generates monthly soiling loss estimates for dust soiling and snow soiling, as well as a monthly albedo profile. By incorporating industry standard models and DNV analytics, precipitation, and snowfall data are automatically accessed and used to estimate the impact on energy generation.

Total PV capacity is forecasted by two different technology configurations: PV Only and PV + Battery. The PV technology in the PV + Battery systems was modeled using the same specifications as the PV Only technology except for nameplate capacity. DNV determined that average system sizes for PV + Battery configurations are, on average, larger than PV Only systems.

DNV further segmented the PV + Battery technology into two categories: new PV + Battery systems installed together and a Battery Retrofit case, where a battery is added to an existing PV system. The PV Only forecast presented in the results section of this report is the net of customers who later adopt an add-on battery system (Battery Retrofit), and therefore become a part of the PV + Battery forecast. DNV assumes that customers in the Battery Retrofit case do not represent new incremental PV MW-AC capacity; however, the generation profile of the customer changes from PV Only to PV + Battery.

An example residential customer load profile for two summer days is presented in Figure 3-1 to illustrate the difference between the generation profiles of PV Only and PV + Battery systems. This example represents peak PV production, and it should be noted that systems located in PacifiCorp territory have different load curves for the winter and rainy seasons.

**Figure 3-1. Example residential summer load shape compared to PV Only and PV + battery generation profiles**




### 3.1.1.1 PV Only

Table 3-1 provides the representative system specifications used to model residential standalone PV adoption. DC/AC ratio assumptions are derived from DNV's experience in the residential PV industry.

**Table 3-1. Residential PV Only representative system assumptions**

| System performance | Units | CA | ID | OR | UT | WA | WY |
|---|---|---|---|---|---|---|---|
| **Nameplate capacity** | kW-DC | 6.5 | 7.3 | 7.1 | 6.2 | 10.0 | 7.2 |
| **Module type** | n/a | c-Si | c-Si | c-Si | c-Si | c-Si | c-Si |
| **PV inverter** | n/a | Microinverter | | | | | |
| **Installation requirements** | n/a | Fixed-tilt roof-mounted | | | | | |
| **Capacity factor** | kWh (kW-DC x 8760 hrs./yr) | 13% | 15% | 16% | 15% | 13% | 16% |
| **DC/AC derate factor** | n/a | 1.118 | 1.123 | 1.121 | 1.129 | 1.132 | 1.118 |

Table 3-2 provides the representative system specification used to model non-residential standalone PV adoption. DC/AC ratio assumptions are derived from Wood Mackenzie's H1 2022 US solar PV system pricing report. The nameplate capacity of the system depends on the average customer size for each non-residential sector and state.

**Table 3-2. Non-residential PV Only representative system assumptions**

| System performance | Units | CA | ID | OR | UT | WA | WY |
|---|---|---|---|---|---|---|---|
| **Nameplate capacity** | kW-DC | 25-129 | 26-123 | 25-253 | 52-138 | 17-98 | 15-25 |
| **Module type** | n/a | c-Si | c-Si | c-Si | c-Si | c-Si | c-Si |
| **PV inverter** | n/a | Three-phase string inverter | | | | | |
| **Installation requirements** | n/a | Flat roof-mounted | | | | | |
| **Capacity factor** | kWh (kW-DC x 8760 hrs./yr) | 14% | 13% | 12% | 14% | 12% | 12% |
| **DC/AC derate factor** | n/a | 1.30 | 1.30 | 1.30 | 1.30 | 1.30 | 1.30 |

The full list of nameplate capacity assumptions by sector and state can be found in section 5. For all PV systems, DNV assumed a linear degradation rate of 0.5% across the expected useful life of the system.

### 3.1.1.2 PV + battery

Technology attributes consist of a representative system, operational data, cost assumptions, and capital costs which are used in conjunction to develop a total installed cost in dollars per kW. DNV reviewed PacifiCorp's history of interconnected projects to develop its customer-level assumptions for a number of batteries, usable energy capacity, and rated power at the state level. The resulting representative composite system is used for operational parameters and costs to be used for long-term adoption and forecasting purposes.

DNV assumes a fully integrated battery energy storage system (BESS) product for the residential sector, which will include a battery pack and a bi-directional inverter based on leading residential battery energy storage manufacturers such as Tesla, Enphase, and Sonnen providing fully integrated BESS solutions. Table 3-3 presents the representative residential PV + Battery system assumptions used in this analysis. The system specifications for the commercial, industrial, and irrigation sectors are listed in Appendix A, section 5.1.

**Table 3-3. Residential PV + battery representative system assumptions**

| Technology | System performance | Units | CA | ID | OR | UT | WA | WY |
|---|---|---|---|---|---|---|---|---|
| **PV** | Nameplate capacity | kW-DC | 8.5 | 8.9 | 8.7 | 7.7 | 12.0 | 8.2 |
| | Total usable energy capacity | kWh | 12.5 | 12.5 | 12.5 | 10.0 | 14.0 | 10.0 |
| | Total power | kW | 5.0 | 5.0 | 7.0 | 5.0 | 7.0 | 5.0 |
| | Battery duration | Hrs | 2.5 | 2.5 | 2.0 | 2.5 | 2.0 | 2.0 |
| | Roundtrip efficiency | % | | | | | | 89% |
| **BESS** | Battery pack chemistry | n/a | Lithium-ion nickel, manganese, cobalt (NMC) | | | | | |

Residential and non-residential BESS can be installed as a standalone system, added to an existing PV system (i.e., battery retrofit), or the system can be installed with a new PV system. DNV assumed all battery installations would be co-located with a PV system in an AC-coupled configuration, as standalone BESS systems are ineligible for the federal IT, as explained in section 3.1.6.

Battery adoption was forecasted separately for PV + Battery systems installed together, and the Battery Retrofit case, where a battery is added to an existing PV system. The basis of the Battery Retrofit forecast is the existing PV capacity in PacifiCorp's service territories and the PV Only capacity forecasted in this analysis. For forecasting distributed generation capacity, the Battery Retrofit forecast is presented in the results section as a part of the PV + Battery capacity forecast. In the BTM battery storage capacity forecast, presented in Appendix 5.3, the Battery Retrofit case is split out in the presentation of the results.

Battery degradation was modeled using DNV's Battery AI, a data-driven battery analytics tool that predicts short-term and long-term useable energy capacity degradation under different usage conditions. It combines laboratory cell testing data with artificial intelligence (AI) technologies to provide an estimation for battery energy capacity degradation over time. In this analysis, Battery AI used several current-generation, commercially available NMC cells to predict the expected degradation performance of "generic" cells. These cells were tested in the lab over six to twelve months at multiple temperatures, C-rates, SOC ranges, and cycling/resting conditions. Predictions are generally constrained within the bounds of the testing data. DNV has not explicitly modeled battery end-of-life (EOL), due to a lack of testing data in this region of operation. Earlier than 20 years or 60% capacity retention is generally considered to represent EOL.

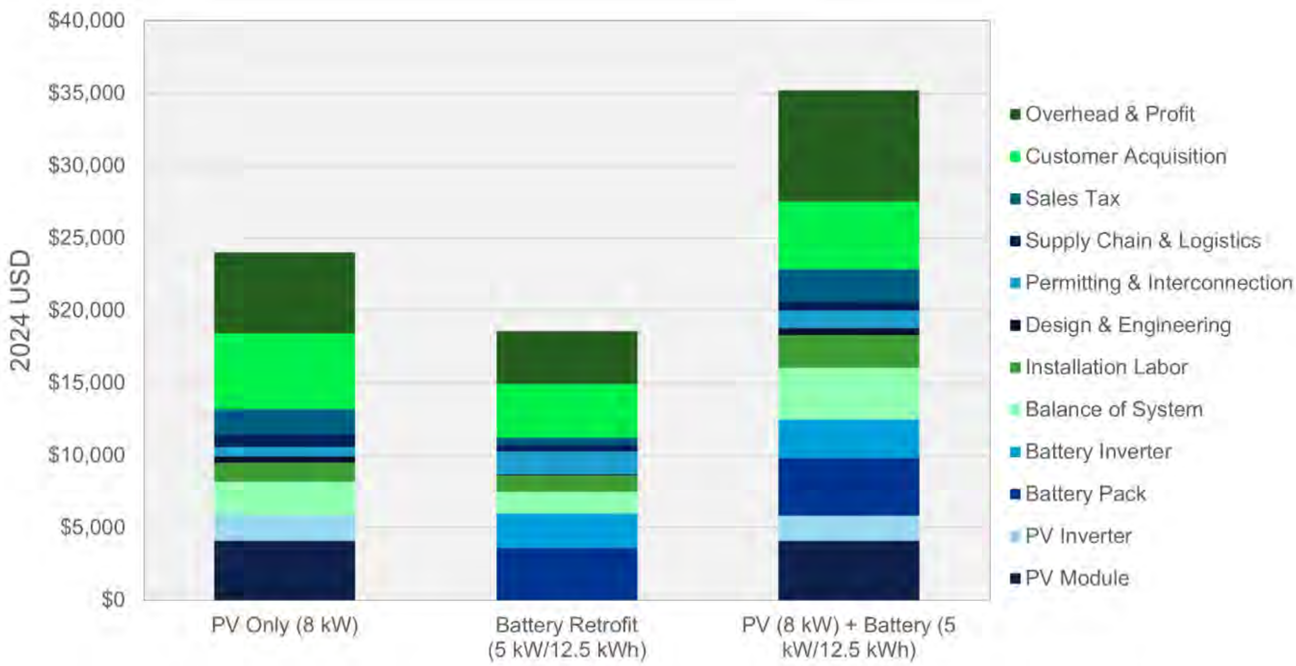
Both cycling and calendar effects were considered in the degradation assessment. It is also assumed the battery cell temperature will be controlled to be around 25°C for the majority of the time with proper thermal management (e.g., ventilation, HVAC). DNV notes that temperature plays a key role in battery degradation. Continuous operation under extremely low or high temperatures will accelerate degradation in the battery's state of health.

**Cost assumptions**

Cost assumptions are used in conjunction with representative system parameters to develop system costs. The costs are developed for each state and sector, including hardware, labor, permitting, interconnection fees, and provisions for sales and marketing, overhead, and profit. For labor costs, we used state-level data from the U.S. Bureau of Labor Statistics (BLS) for electricians, laborers (construction), and electrical engineers.

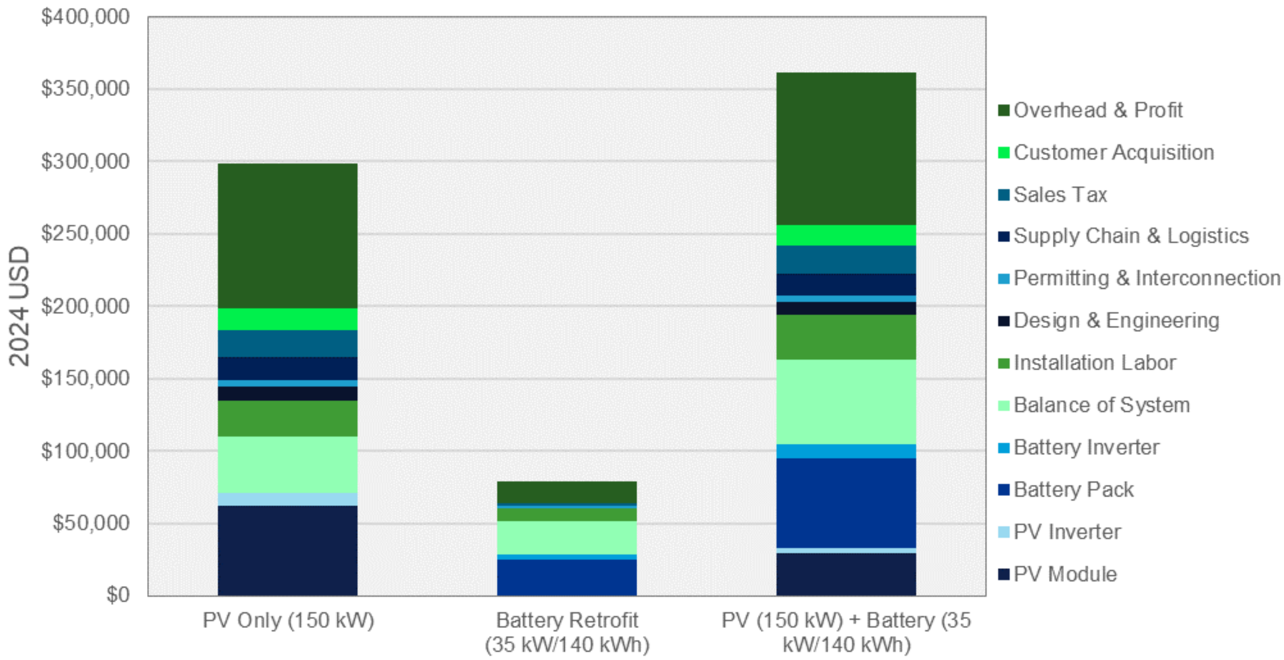
Total installed costs (or capital expenditures) are based on cost assumptions developed on a bottom-up basis—including hardware, installation/interconnection, as well as a provision for sales, general, and administrative costs, and overhead. Capital expenditures (Cap-Ex) are expenditures required to achieve commercial operation in a given year. Pricing indicates a cash sale, not a lease or Power Purchase Agreement (PPA), and it does not account for Investment Tax Credit (ITC) or local rebates. Examples of total installed costs by category for residential and commercial customers in Utah are shown in Figure 3-2 and Figure 3-3, respectively. The full set of cost and incentive assumptions used in the analysis can be found in Appendix A, section 5.1.

**Figure 3-2. Cost of residential PV standalone, battery storage retrofit to existing PV, and PV + battery systems from DNV bottom-up Cap-Ex Model, Utah[1]**




[1] Costs are presented as all-in costs before tax credits.

**Figure 3-3. Cost of commercial PV standalone, battery storage retrofit to existing PV, and PV + battery systems from DNV bottom-up Cap-Ex Model, Utah[1]**




[1] Costs are presented as all-in costs before tax credits.

DNV has estimated all CapEx categories for the projects based on Wood Mackenzie's US 2022 H1 cost model, which is reasonable relative to the actual CapEx that DNV has observed on past projects. DNV estimated the benchmark CapEx values based on the project capacity, location, and technology assumptions for each state and sector. When technology assumptions were unavailable, DNV made reasonable assumptions. Combined PV + Battery systems were assumed to have cost efficiencies in certain categories that would reduce the total cost of the system when installed at the same time. Cap-Ex categories assumed to have cost efficiencies for combined systems include electrical and structural balance of system, installation labor, design & engineering, permitting, interconnection & inspection costs, customer acquisition costs, supply chain & logistics, and overhead & profit costs.

DNV used a blended version of the NREL Annual Technology Baseline[4] moderate and conservative solar PV and battery energy storage system technology cost forecasts in the base case of this distributed generation forecast. The average residential and non-residential PV system cost forecasts are presented in Figure 3-4 and Figure 3-5, and the average residential and non-residential battery cost forecasts are shown in Figure 3-6 and Figure 3-7.

[4] NREL (National Renewable Energy Laboratory). 2023. 2023 Annual Technology Baseline. Golden, CO: National Renewable Energy Laboratory.

DNV reviewed the costs presented in the NREL dataset and found that the moderate cost decline forecast for solar PV was much more aggressive than what DNV's national cost models are predicting and what has been seen in the market historically. The technology cost forecast used in the base case has a 37% price decrease in the first 10 years, as opposed to the 50% decrease forecasted in the NREL moderate case. Base year costs were developed for each state, and then the forecasts were applied to each base year cost (by state, technology, and scenario) to get future year costs.

**Figure 3-4. Average residential solar PV system costs, 2022-2043**

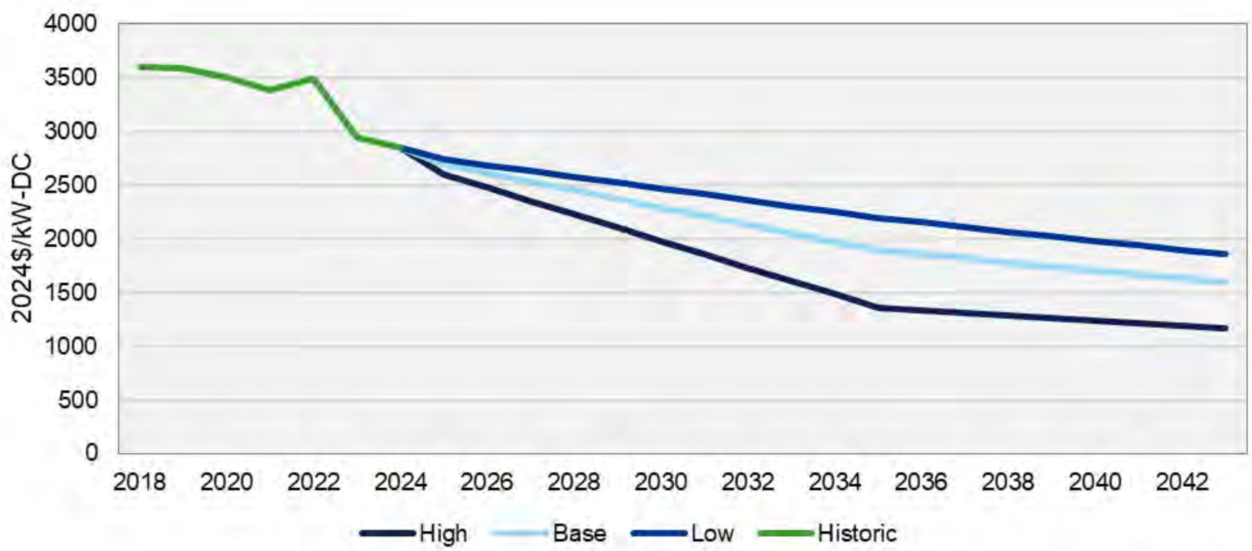



**Figure 3-5. Average non-residential solar PV system costs, 2023-2043**

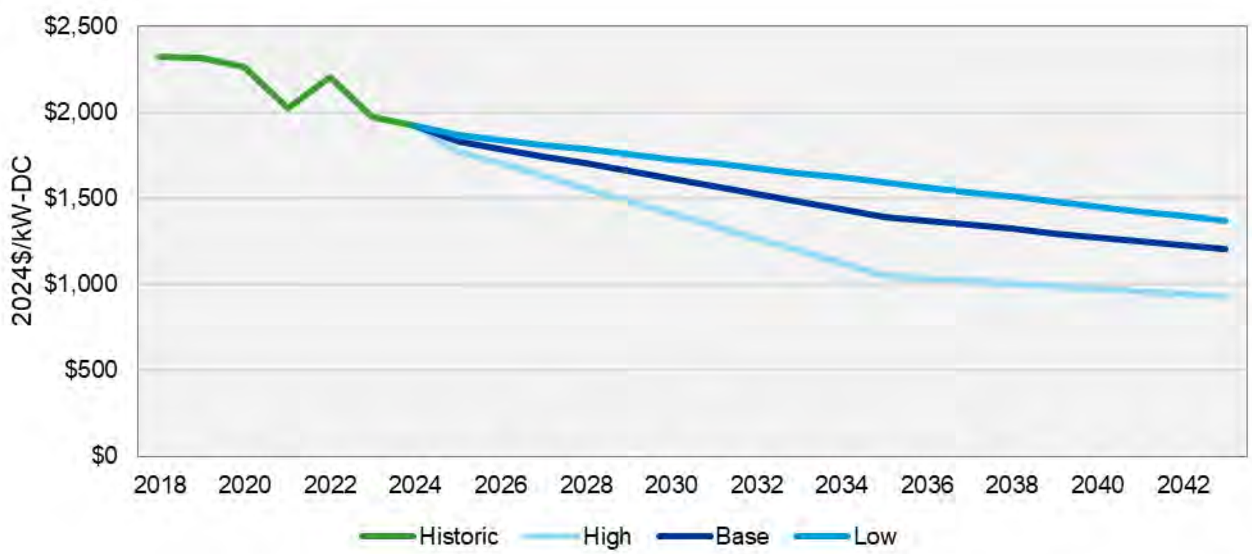


**Figure 3-6. Average residential battery energy storage system (AC-coupled) costs, 2024-2043**

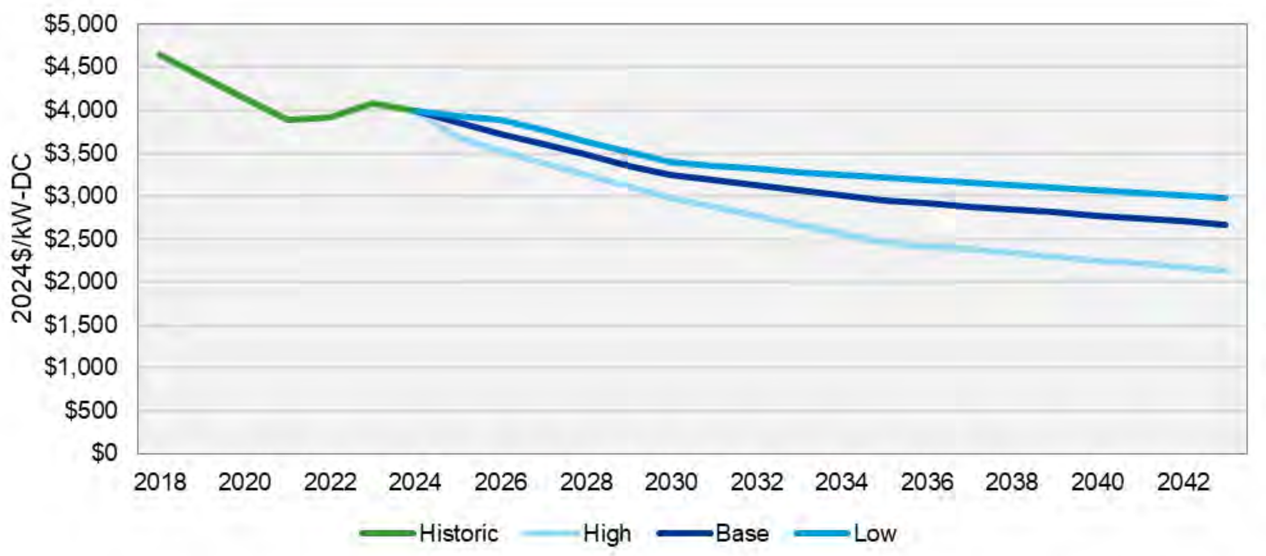
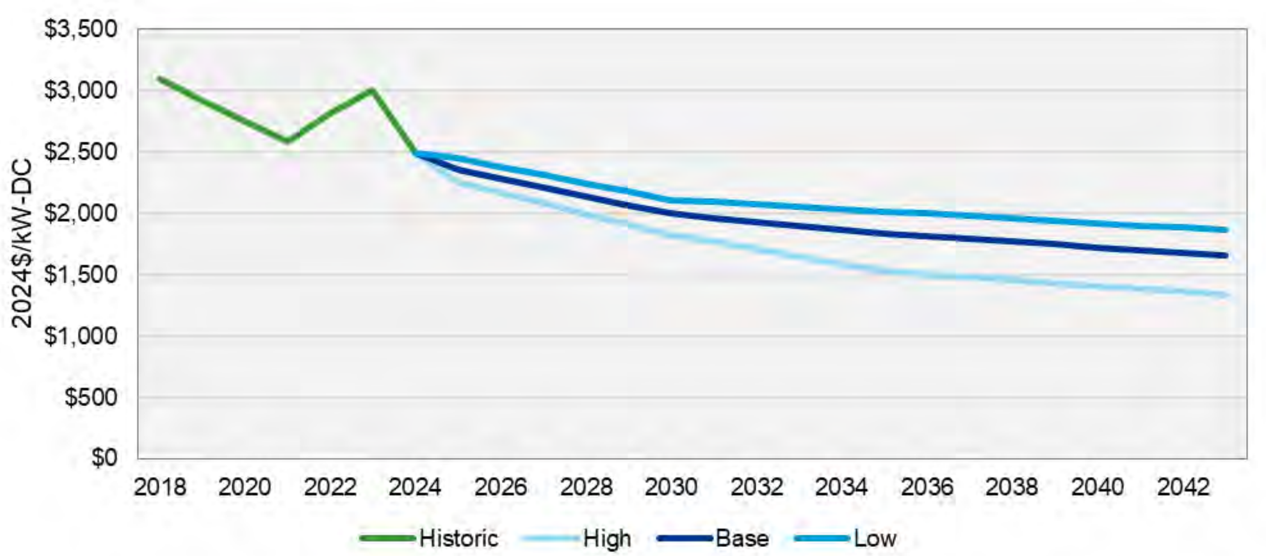



**Figure 3-7. Average non-residential battery energy storage system (AC-coupled) costs, 2024-2043**




### 3.1.2 Small-scale wind

Distributed wind technology is a relatively mature DER. Small-scale wind systems typically serve rural homes, farms, and manufacturing facilities due to their size and land requirements. Wind turbines generate electricity by converting the kinetic energy in the wind into rotating shaft power that spins an AC generator.

Assumptions on system capacity sizes in each state and sector are detailed in Appendix A, section 5.1. Table 3-4 provides the cost and performance assumptions used in the small-scale wind forecast and the source for each.

**Table 3-4. Small wind assumptions**

| Cost & performance metric | Units | Residential (20 kW or less) | Commercial (21-100 kW) | Midsize (101-999 kW) | Sources |
|---|---|---|---|---|---|
| Installed cost | 2024$/kW | $7,054 | $3,917 | $2,931 | NREL, 2022. Distributed Wind Energy Futures Study. https://www.nrel.gov/docs/fy22osti/82519.pdf |
| Annual installed cost change | %, 2024-2043 | | | -1.9% | NREL. 2021. "2021 Annual Technology Baseline." Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/ |
| Fixed O&M | 2024$/kW-yr | $38 | $38 | $38 | NREL, 2022. Distributed Wind Energy Futures Study. https://www.nrel.gov/docs/fy22osti/82519.pdf |
| Annual fixed O&M cost change | %, 2024-2043 | -3.5% | -1.9% | -1.9% | NREL. 2023. "2023 Annual Technology Baseline." Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/ |
| Capacity Factor (dependent on state) | % | 7.7-10.8% | 15.1%-18.5% | 15.2%-18.4% | System Advisor Model Version 2023.12.17. National Renewable Energy Laboratory. Golden, CO. https://sam.nrel.gov |

## 3.1.3 Small-scale hydropower

Hydroelectric power is an established, mature technology, but small-scale systems are a newer permutation of the technology and are still quite costly compared to other distributed generation technologies. Small hydro systems generate electricity by transforming potential energy from a water source into kinetic energy that rotates the shaft of an AC generator. Assumptions on system capacity sizes in each state and sector are detailed in Appendix A, section 5.1. Table 3-5 provides the cost and performance assumptions used in the small hydro forecast and the source for each.

**Table 3-5. Small hydro assumptions**

| Cost & performance metric | Units | Micro-hydro (100 kW or less) | Mini-hydro (100 kW-1 MW) | Sources |
|---|---|---|---|---|
| Installed cost | 2024$/kW | $5,190 | $3,892 | International Renewable Energy Agency (IRENA). 2012. "Renewable Energy Cost Analysis: Hydropower" |
| Annual installed cost change | %, 2024-2043 | | -0.2% | NREL. 2021. "2021 Annual Technology Baseline." Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/ |
| Fixed O&M | 2024$/kW-yr | $208 | $156 | International Renewable Energy Agency (IRENA). 2012. "Renewable Energy Cost Analysis: Hydropower" |
| Annual fixed O&M cost change | %, 2024-2043 | | -1.9% | NREL. 2023. "2023 Annual Technology Baseline." Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/ |
| Capacity factor | % | 45% | 45% | International Renewable Energy Agency (IRENA). 2012. "Renewable Energy Cost Analysis: Hydropower" |

### 3.1.4 Reciprocating engines

Combined heat and power (CHP), or cogeneration, is a mature technology that has been used in the power sector and as a distributed generation resource for decades. The two most common CHP technologies for commercial and small- to medium-industrial applications are reciprocating engines and microturbines, used to produce both onsite power and thermal energy.

Reciprocating engines are a mature, reliable technology that performs well at part-load operation in both baseload and load-following applications. Reciprocating engines can be operated with a wide variety of fuels; however, this analysis assumes natural gas is used to generate electricity as it is the most commonly used fuel in CHP applications. A reciprocating engine uses a cylindrical combustion chamber with a close-fitting piston that travels the length of the cylinder. The piston connects to a crankshaft that converts the linear motion of the piston into a rotating motion. Reciprocating engines start quickly and operate on normal natural gas delivery pressures without additional gas compression. The thermal energy output from system operation can be used to produce hot water, low-pressure steam, or chilled water with the addition of an absorption chiller. Typical CHP applications for reciprocating engine systems in the Pacific Northwest include universities, hospitals, wastewater treatment facilities, agricultural applications, commercial buildings, and small- to medium-sized industrial facilities.[5]

Assumptions on system capacity sizes in each state and sector are detailed in Appendix A, section 5.1. Two representative reciprocating engine sizes were used in this analysis based on the ability to meet the average customer's minimum electric load, ranging from less than 100 kW to 1 MW. Table 3-6 provides the cost and performance assumptions used in the reciprocating engine forecast and the source for each.

**Table 3-6. Reciprocating engine assumptions**

| Cost & performance metric | Units | Small (100 kW or less) | Medium (100 kW-1 MW) | Sources |
|---|---|---|---|---|
| Installed cost | 2024$/kW | $4,189 | $3,125 | "A Comprehensive Assessment of Small Combined Heat and Power Technical and Market Potential in California." 2019. California Energy Commission. |
| Annual installed cost change | %, 2024-2043 | | -0.5% | NREL. 2023. "2023 Annual Technology Baseline." Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/ |
| Variable O&M | 2024$/MWh | $28 | $20 | "A Comprehensive Assessment of Small Combined Heat and Power Technical and Market Potential in California." 2019. California Energy Commission. |
| Annual variable O&M cost change | %, 2024-2043 | | -1.9% | NREL. 2023. "2023 Annual Technology Baseline." Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/ |
| Electric heat rate (HHV) | Btu/kWh | 11,765 | 9,721 | "A Comprehensive Assessment of Small Combined Heat and Power Technical and Market Potential in California." 2019. California Energy Commission. |

5 U.S. Department of Energy Combined Heat and Power and Microgrid Installation Databases (2024). Available at: https://doe.icfwebservices.com/chp.

### 3.1.5 Microturbines

Microturbines are another CHP application commonly used in smaller commercial and industrial applications. They are smaller combustion turbines that can be stacked in parallel to serve larger loads and provide flexibility in deployment and interconnection at customer sites. Microturbines can use gaseous or liquid fuels, but for CHP applications natural gas is the most common fuel. Therefore, for this analysis, DNV assumed microturbines would use natural gas to generate electricity and thermal energy at customer sites. Microturbines operate on the Brayton thermodynamic cycle where atmospheric air is compressed, heated by burning fuel, and then used to drive a turbine that in turn drives an AC generator. A microturbine can have exhaust temperatures in the range of 500 to 600ºF, which can be used to produce steam, hot water, or chilled water with the addition of an absorption chiller in CHP applications. Microturbine efficiency declines significantly as load decreases; therefore the technology is best suited to operate in base load applications operating at or near full system load. Common microturbine CHP installations in the Pacific Northwest include small universities, commercial buildings, small manufacturing operations, hotels, and wastewater treatment facilities.[6]

Assumptions on system capacity sizes in each state and sector are detailed in Appendix A, section 5.1. This analysis used two representative microturbine sizes based on the ability to meet the average customer's minimum electric load, ranging from less than 100 kW to 1 MW. Table 3-7 provides the cost and performance assumptions used in the microturbines forecast and the source for each.

**Table 3-7. Microturbine assumptions**

| Cost & performance metric | Units | Small (less than 100 kW) | Medium (100 kW-1 MW) | Sources |
|---|---|---|---|---|
| Installed cost | 2024$/kW | $3,742 | $3,134 | "A Comprehensive Assessment of Small Combined Heat and Power Technical and Market Potential in California." 2019. California Energy Commission. |
| Annual installed cost change | %, 2024-2043 | | -0.6% | NREL. 2023. "2023 Annual Technology Baseline." Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/ |
| Variable O&M | 2024$/MWh | $19 | $15 | "A Comprehensive Assessment of Small Combined Heat and Power Technical and Market Potential in California." 2019. California Energy Commission. |
| Annual variable O&M cost change | %, 2024-2043 | | -1.9% | NREL. 2023. "2023 Annual Technology Baseline." Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/ |
| Electric heat rate (HHV) | Btu/kWh | 13,648 | 11,566 | "A Comprehensive Assessment of Small Combined Heat and Power Technical and Market Potential in California." 2019. California Energy Commission. |

### 3.1.6 Incentives overview

Since the passing of the IRA, the ITC has been extended 10 years past its original expiration date. For facilities beginning construction before January 1, 2025, the IRA extends the ITC for up to 30% of the cost of installed equipment through 2032 and is assumed to step down to 26 in 2033 and 22% in 2034. For projects beginning construction after 2019 that are placed in service before January 1, 2022, the ITC would be set at 26%. In addition to the new federal ITC schedule for generating

[6] Ibid

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. Energy storage installations that begin construction after Dec. 31, 2024, will be entitled to credits under the technology-neutral ITC under new Section 48E. The base ITC rate for energy storage projects is 6% and the bonus rate is 30%. The IRA also includes a 5-year MACRS depreciation schedule for non-residential (i.e., Solar Photovoltaics, Wind (All), Wind (Small), and Microturbines. The federal tax credits in Table 3-8 were included in the economic analysis of all distributed generation forecast scenarios. Since there are complexities related to the ability to apply and receive tax credits for larger DG systems, future modeling assumptions could take into account historical data to apply factors that align with the tax credit percentage granted.

The U.S. EPA Solar for All program issued a $7 billion Notice of Funding Opportunity in 2023. This opportunity provides funding for 60 grants to states, territories, Tribal governments, municipalities, and nonprofits to create and expand programs that provide financing and technical assistance to bring residential solar to low-income and disadvantaged communities. The funding availability assumptions incorporated into state-level incentives for solar PV aligned with residential LMI segments.

**Table 3-8. Federal investment tax credits for DERs**

*Cells in green represent the transition to a technology-neutral ITC for clean energy technologies with 0 gCO2e emissions per kWh, under section 48D.*

| Incentive | System size (kW) | Technology | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035+ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential / Business ITC | < 1,000 | PV | 30% | 30% | 30% | 30% | 30% | 30% | 30% | 30% | 30% | 26% | 22% | 0% |
| | < 1,000 | Energy Storage | 30% | 30% | 30% | 30% | 30% | 30% | 30% | 30% | 30% | 26% | 22% | 0% |
| | < 1,000 | Small Wind | 30% | 30% | 30% | 30% | 30% | 30% | 30% | 30% | 30% | 26% | 22% | 0% |
| Business ITC | < 1,000 | Microturbines | 30% | 30% | 30% | 30% | 30% | 30% | 30% | 30% | 30% | 26% | 22% | 0% |
| | < 1,000 | Reciprocating Engines | 30% | 30% | 30% | 30% | 30% | 30% | 30% | 30% | 30% | 26% | 22% | 0% |
| | < 150 | Small Hydro (hydropower dams) | 30% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| | < 25 | Small Hydro (Hydrokinetic pressurized conduits) | 30% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| | < 1,000 | Small Hydro | 0% | 30% | 30% | 30% | 30% | 30% | 30% | 30% | 30% | 26% | 22% | 0% |

A summary of the state incentives included in the economic analysis is provided below in Table 3-9.

Table 3-9. State Incentives for DERs

| State | Residential | | Non-residential |
|---|---|---|---|
| **Oregon**[7] | **PV-Only:** $450/home, $3,000 max/home | **Battery Storage:** $250/kWh, $3,000 max/home | **PV-Only:** $0.15/W (up to 480 kW) |
| **Utah**[8] | **PV-Only:** None (expired in 2023) | **Non-PV:** 25% of eligible system cost (up to $2,000) | Up to 10% of the eligible system cost or up to $50,000* |
| **Idaho**[9] | Annual maximum of $5,000, and $20,000 over four years** | | None |
| **California** | None | | None |
| **Washington** | None | | WA provides a sales tax exception for PV purchases >100-500 kW installations. These are split between Category 1 (>500 kW) and Category 2 (100-500 kW) |
| **Wyoming** | None | | None |

* Solar PV, wind, geothermal, hydro, biomass, or certain renewable thermal technologies

** Mechanism or series of mechanisms using solar radiation, wind, or geothermal resource

*** Note that incentives from Rocky Mountain Power's Wattsmart battery program were also included in the modeling process

7 Incentives are provided through the Energy Trust of Oregon (Solar for Your Home, Solar Within Reach, and Solar for Your Business) and the Oregon Department of Energy (Solar + Storage Rebate Program for Low-Moderate Income and Non-Income Restricted Homeowners). https://energytrust.org/programs/solar/; https://www.oregon.gov/energy/Incentives/Pages/Solar-Storage-Rebate-Program.aspx Funding for the Oregon Solar + Storage Rebate Program is fully reserved as of May 2024, and ODOE is no longer accepting applications.

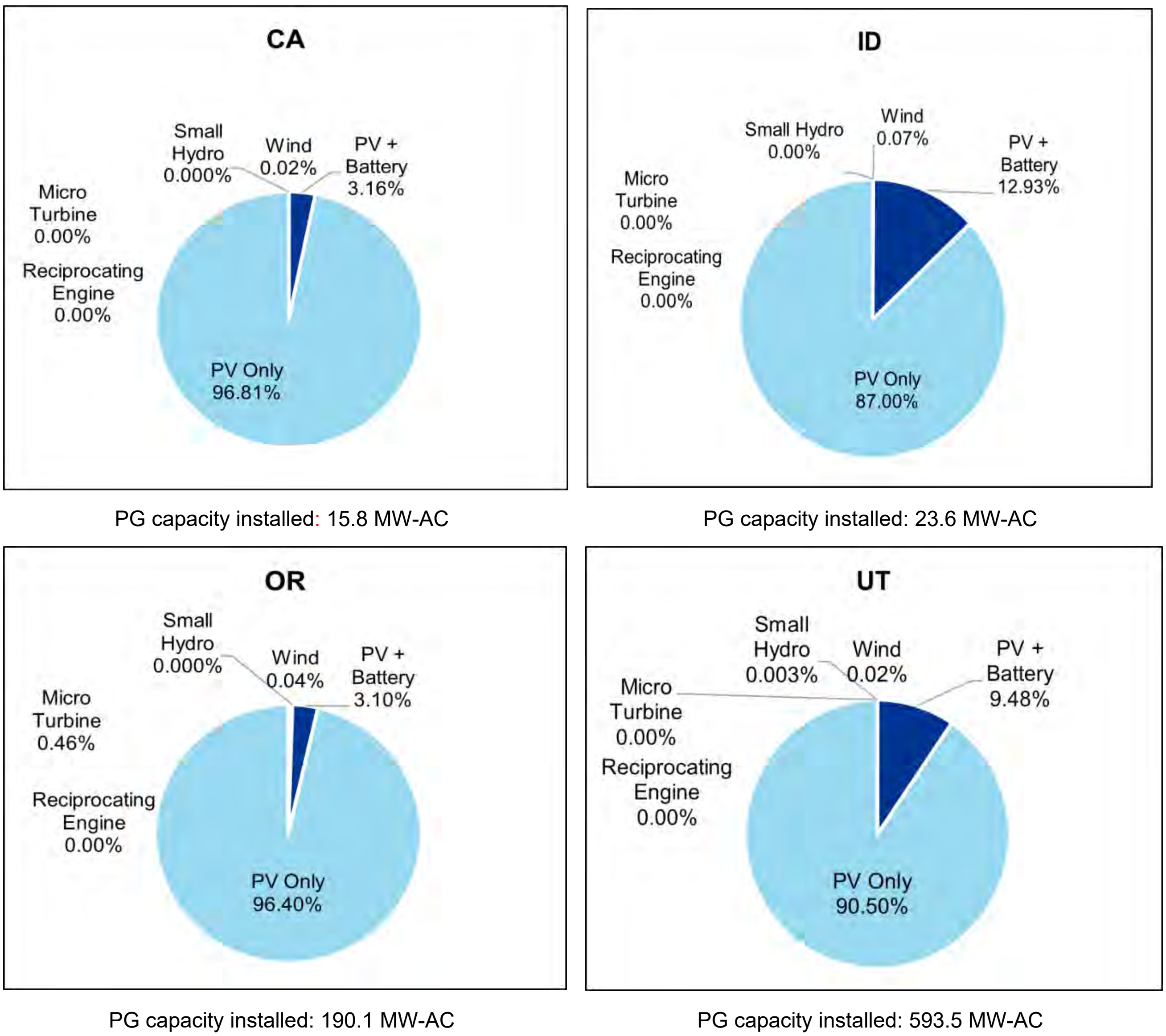
8 Incentives are provided through the Utah Office of Energy Development Renewable Energy Systems Tax Credit. https://energy.utah.gov/tax-credits/renewable-energy-systems-tax-credit/

9 Incentives are provided through the State of Idaho Renewable Alternative Tax Deduction. https://legislature.idaho.gov/statutesrules/idstat/title63/t63ch30/sect63-3022c/

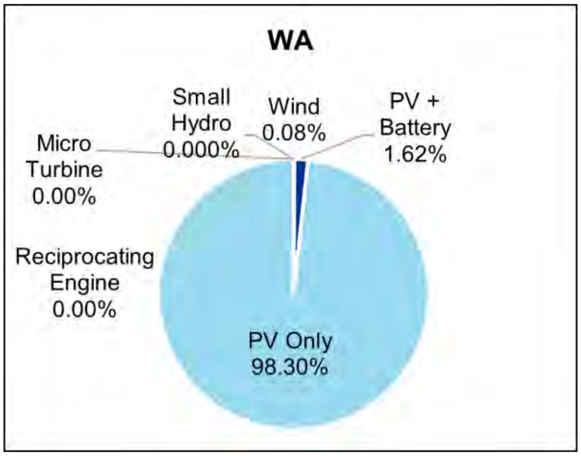
## 3.2 Current distributed generation market

To date, about 99% of the existing distributed generation capacity installed in PacifiCorp's service territory is PV or PV + Battery.[10] To inform the adoption forecast process, DNV conducted an in-depth review of the other technologies and did not find any literature to suggest that they would take on a larger share of the distributed generation market in the Company's service territory in the future years of this assessment. Figure 3-8 shows the current share of distributed generation capacity by technology in each of PacifiCorp's six-state service territories.

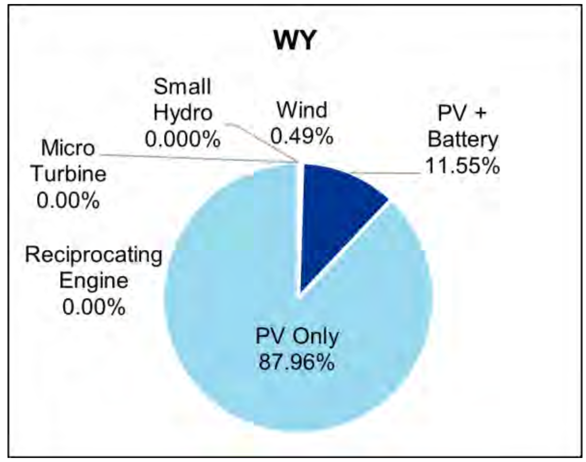
**Figure 3-8. Cumulative installed distributed generation capacity by state, by technology, as of March 31, 2024**




10 PacifiCorp distributed generation interconnection data as of April 2024.




PG Capacity Installed: 38.9 MW-AC




PG Capacity Installed: 6.5 MW-AC

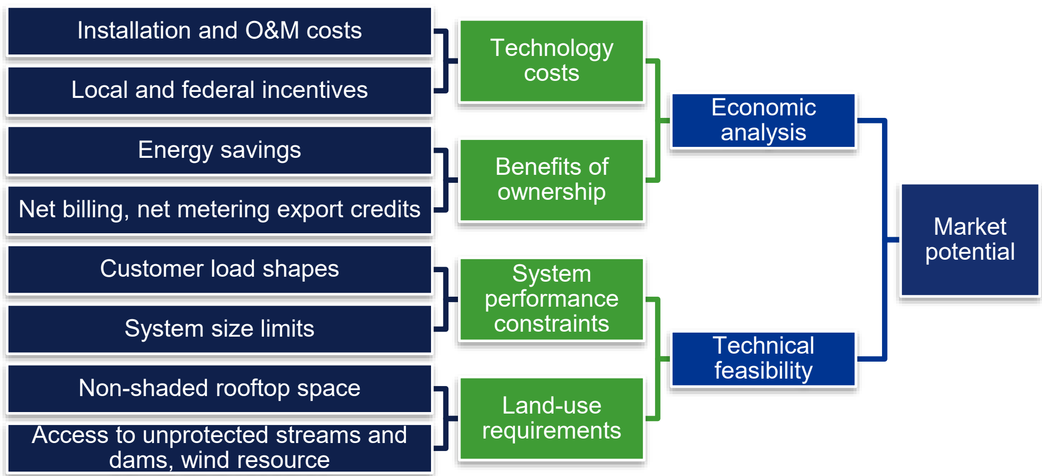
Section 3.3.3 details how the historic distributed generation adoption data is used in the distributed generation forecast modelling process.

## 3.3 Forecast methodology

DNV combined technical feasibility characteristics of the identified distributed generation technologies and potential customers with an economic analysis to calculate cost-effectiveness metrics for each technology, within each state that PacifiCorp serves, over the analysis timeframe. DNV then used a Bass diffusion model to estimate customer adoption based on technical and economic feasibility and incorporated existing adoption of each technology by state and customer segment as input to the adoption model.

Technical feasibility characteristics were used to identify the potential customer base that could technically support the installation of a specific distributed generation technology, or the maximum, feasible, adoption for each technology by sector. These factors included overall distributed generation metrics such as average customer load shapes and system size limits by state, and specific technology factors such as estimated rooftop space and resource access based on location (for hydro and wind resource applicability). Simple payback was used in the customer adoption portion of the model as an input parameter to Bass diffusion curves that determined the future penetration of all technologies. Figure 3-9 provides a visual representation of how different inputs were used in different portions of the model. Additional details on the economic and adoption approaches used in this analysis are provided in the subsequent sections.

**Figure 3-9. Methodology to determine market potential of distributed generation adoption**




## 3.3.1 Economic analysis

The economic analysis portion of overall customer adoption was used as a key factor in the Bass diffusion model that calculated future distributed generation adoption. DNV used simple payback as the preferred method of estimating economic viability based on customer perspectives given its widespread use in similar adoption analyses, ability to reflect customer decision-making in forecasting efforts, and ease of estimation.

DNV developed a behind-the-meter net economic perspective that includes, as costs, the acquisition and installation costs for each technology less the impact of available incentives and, as benefits, the customer's economic benefits of ownership such as energy and demand savings and export credits. For this assessment, we assumed that the current net metering or net billing policies and tariff structures in each state continued throughout the study horizon. This resulted in the model incorporating benefits associated with net metering in Oregon, Washington, and Wyoming and net billing in Utah and California. We assumed customers in Idaho would accrue benefits based on the net billing policy in Utah throughout the study.

A detailed breakdown of the simple payback calculation and different elements is shown below.

$$\boldsymbol{Simple\ Payback} = \frac{Cumulative\ Net\ Costs}{Cumulative\ Net\ Benefits}$$

$$\boldsymbol{Cumulative\ Net\ Costs} = (Upfront\ System\ Cost - Year\ One\ Incentives) + NPV(Annual\ O\&M\ Costs + Annual\ Fuel\ Costs)$$

$$\boldsymbol{Cumulative\ Net\ Benefits} = NPV(MACRS\ Savings +\ Self\ Consumption\ Savings + Export\ Credits + Peak\ Demand\ Savings)$$

DNV also used an annual hourly profile analysis to estimate electric bill savings and excess generation for each distributed generation technology by customer segment. This analysis used hourly generation and customer load profiles, and tiered, time-of-use (TOU), and peak demand rates for each customer segment and technology permutation. DNV integrated the energy savings, excess generation, and peak demand benefits into the lifetime simple payback estimation using customer load and individual rate forecasts provided by PacifiCorp. A full breakdown of all inputs used in the economic analysis is provided in Table 3-10 below.

**Table 3-10. Distributed generation forecast economic analysis inputs[1]**

| Input type | Cost/benefit category | Source |
|---|---|---|
| **Technology cost data – installed cost** | Distributed generation cost data compiled in \$/kW (AC & DC) – used in determining year one installed system costs | DNV |
| **Technology cost data – annual O&M** | Distributed generation fixed (\$/kW) & variable (\$/kWh) O&M data – used in determining annual system costs | DNV |
| **Fuel cost data** | Natural gas cost data (\$/MMBtu) | EIA Annual Energy Outlook 2024 |
| **Technology generation profiles** | Hourly generation profiles for each technology by state – used in calculating self-consumption savings, excess generation credits, and peak demand savings | DNV |
| **Customer load profiles** | Hourly average customer load profiles by state – used in calculating self-consumption savings, excess generation credits, and peak demand savings | PacifiCorp |
| **Customer rates** | Customer tiered, TOU, and peak demand rates by size, segment, and state – used in calculating self-consumption savings, excess generation credits, and peak demand savings | PacifiCorp |
| **Technology cost forecasts** | Distributed generation cost data forecasts for installed system costs and annual O&M costs – used in determining year one installed system costs and future year annual system costs | NREL Annual Technology Baseline (ATB) |
| **Customer & load forecasts** | Individual customer count and load (kWh) forecasts by customer segment and state – used in calculating future year system costs and benefits | PacifiCorp |
| **Customer rate forecasts** | Rate forecasts applied to each customer segment – used in calculating future year self-consumption savings, excess generation credits, and peak demand savings | EIA Annual Energy Outlook 2024<br>PacifiCorp |

[1]Detailed input data can be found in Appendix section 5.1 (Appendix Attachment A)

DNV calculated simple payback for each technology (solar PV, solar PV + battery, wind, hydro, reciprocating engines, and microturbines) by applicable individual customer segments (residential, commercial, industrial, and irrigation) for each installation year in the analysis timeframe (2024 – 2035). These payback results were combined with technical feasibility by customer segment and integrated into the Bass diffusion adoption model to determine annual distributed generation penetration throughout PacifiCorp's territory.

### 3.3.2 Technical feasibility

The maximum amount of the technically feasible capacity of distributed generation was determined individually for each technology considered in the distributed generation forecast. Each technology was generally limited by customer access factors, system size limits, and energy consumption. The customer load shapes, provided by PacifiCorp, were used to calculate annual energy use (kWh) cutoffs used in identifying the total number of customers that could technically support the installation of a specific technology. Other data sources specific to each technology were used to determine the amount of capacity that can be physically installed within PacifiCorp's service territory, such as:

- Hydropower potential data and environmental attributes for all HUC10 watersheds in PacifiCorp's service territory[11]
- Building rooftop hosting area and suitability for solar PV[12]
- Wind resource potential data by state[13]

### 3.3.3 Market adoption

DNV modeled market adoption using Bass diffusion curves customized to each state, technology, and sector. The Bass diffusion model was developed in the 1960s and is widely used to model market adoption over time.

The formula for new adoption of a technology in year t is given by[14]

$$s(t) = m\,\frac{(p+q)^2}{p}\,\frac{e^{-t(p+q)}}{(1+\frac{q}{p}e^{-t(p+q)})^2}$$

<u>Where:</u>

***s(t)*** is new adopters at time *t*

***m*** is the ultimate market potential

***p*** is the coefficient of innovation

***q*** is the coefficient of imitation

***t*** is time in years

Figure 3-10 shows a generalized Bass diffusion curve. The cumulative adoption curve takes a characteristic "S" shape with a new unknown and unproven technology having relatively slow adoption that accelerates over time as the technology becomes more familiar to a wider segment of the population. As the pool of potential buyers who have not yet adopted the technology shrinks, the rate of adoption (as a percent of the total pool of potential adopters) decreases until eventually everyone who will adopt has adopted. The corresponding chart shows the rate of annual new adoption.

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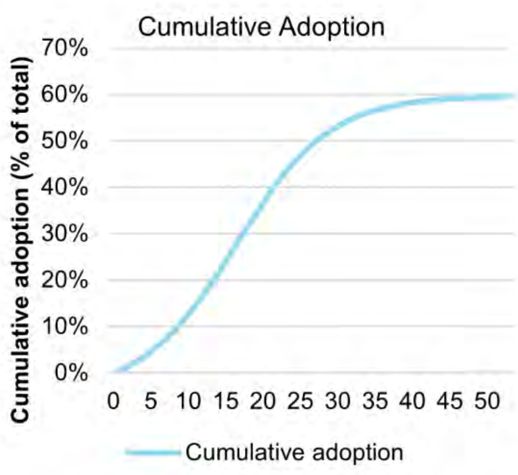
[11] Kao, Shih-Chieh, Mcmanamay, Ryan A., Stewart, Kevin M., Samu, Nicole M., Hadjerioua, Boualem, Deneale, Scott T., Yeasmin, Dilruba, Pasha, M. Fayzul K., Oubeidillah, Abdoul A., and Smith, Brennan T. New Stream-reach Development: A Comprehensive Assessment of Hydropower Energy Potential in the United States. United States: N. p., 2014. Web. doi:10.2172/1130425.

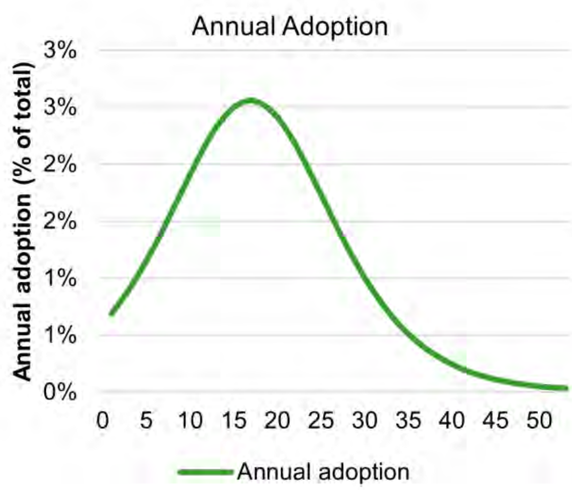
[12] Gagnon, P., R. Margolis, J. Melius, C. Phillips, and R. Elmore. 2016. Rooftop Solar Photovoltaic Technical Potential in the United States: A Detailed Assessment. NREL/TP-6A20-65298. Golden, CO: National Renewable Energy Laboratory.

[13] Draxl, C., B.M. Hodge, A. Clifton, and J. McCaa. 2015. "The Wind Integration National Dataset (WIND) Toolkit." Applied Energy 151: 355366.

[14] Bass, Frank (1969). "A new product growth for model consumer durables". Management Science. 15 (5): 215–227

Figure 3-10. Bass diffusion curve illustration




In the illustration, the cumulative curve approaches 60% market penetration asymptotically, corresponding to the value of *m* (ultimate market potential) that we chose for the illustration. For our adoption models, we tied the value of *m* to payback, following Sigrin and Drury's[15] survey findings on willingness to pay for rooftop photovoltaics based on payback. Because payback varied by technology, state, and sector, so did the Bass diffusion curve.

Due to regional and sectoral differences, we made significant adjustments to the willingness-to-adopt curves to better align with the observed relationship between historic cost-effectiveness and current market adoption by technology, state, and sector in PacifiCorp's service territory. Based on PacifiCorp data on current and recent levels of distributed generation adoption, Utah in particular showed higher adoption than published willingness-to-pay curves would suggest, which we believe may be due to regional variation in how customers value resilience. To account for this variation across states, we developed three willingness-to-adopt curves to capture observed state variation. Table 3-11 shows which willingness-to-adopt curve was used for solar for each state and sector. Current adoption for the other modeled technologies was too low to discern variation across states, so we assumed the average propensity to adopt for wind, small hydro, reciprocating engines, and microturbines.

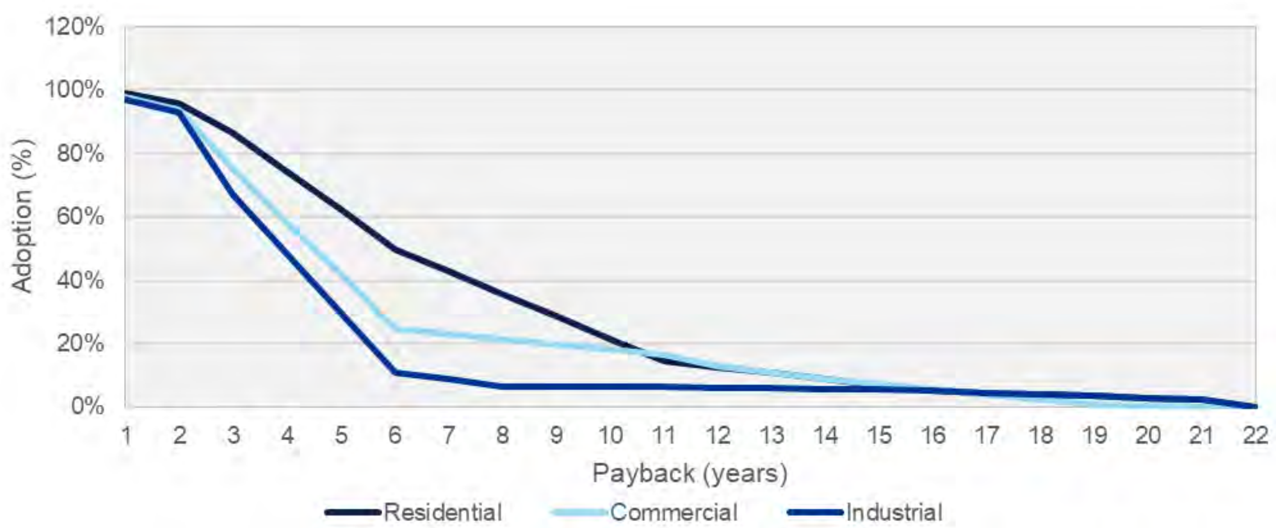
Table 3-11. Solar willingness-to-adopt curve used by state and sector

| Average propensity to adopt | High propensity to adopt | Low propensity to adopt |
|---|---|---|
| • California residential, commercial, irrigation<br>• Idaho & Oregon residential<br>• Washington all sectors | • Utah all sectors<br>• Oregon commercial, industrial, irrigation | • Wyoming all sectors<br>• Idaho commercial, industrial, irrigation<br>• California industrial |

15 Sigrin, Ben and Easan Drury. 2014. Diffusion into New Markets: Economic Returns Required by Households to Adopt Rooftop Photovoltaics. Energy Market Prediction: Papers from the 2014 AAAI Fall Symposium

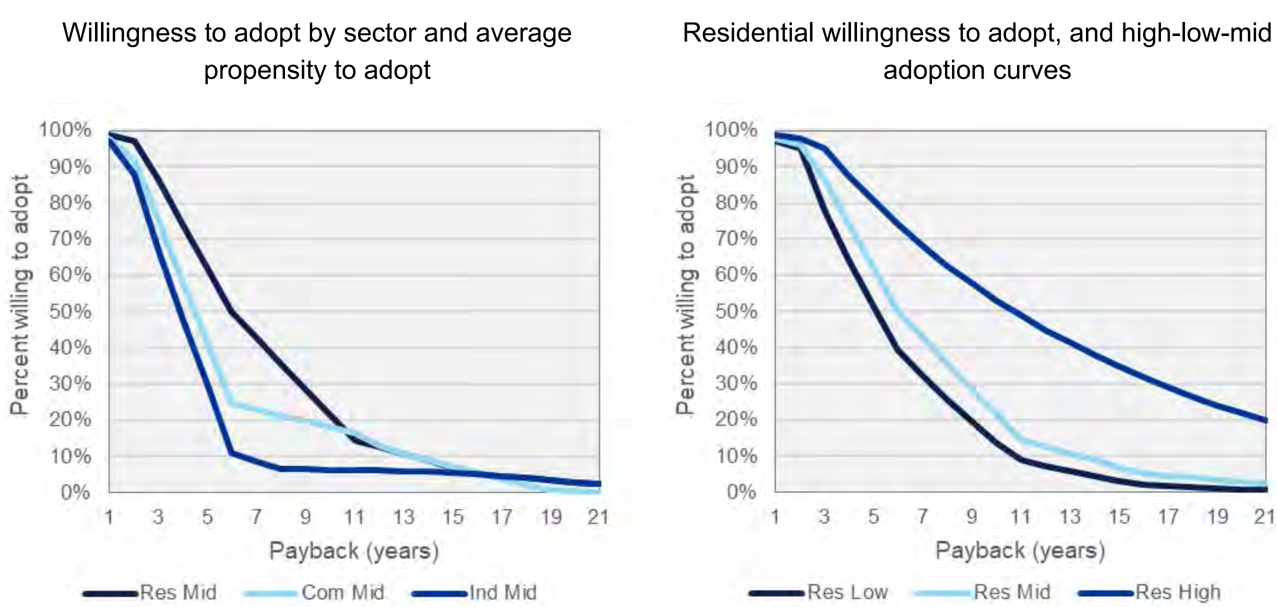
Figure 3-11 shows the willingness-to-adopt curves for residential, commercial, and industrial sectors assuming an average propensity to adopt (the "Mid" case). There was too little irrigation adoption to assess the sector independently, so we used the commercial curves for the irrigation sector.

**Figure 3-11. Willingness to adopt based on technology payback**




The right-hand chart in Figure 3-12 shows the high, mid, and low adoption curves for the residential sector only. The high and low curves for the other sectors show similar variation on the left.

**Figure 3-12. Willingness to adopt based on technology payback, by sector and scenario**



The willingness-to-adopt curves established a different *m* parameter for each diffusion curve. In addition to varying by technology, state, and sector, *m* also changed over time due to changing payback resulting from changing technology costs, incentives, and tax credits, among other economic factors).

The timing of our modeled adoption also varied, as we set $t_0$ for each diffusion curve based on the earliest adoption of each technology by state and sector. For example, the first residential PV installed in PacifiCorp's Oregon service territory was in 2000, while the first commercial PV installation in its Idaho service territory wasn't until 2010. For technology/state/sectors where there is currently no adoption, we assumed that the first adoption would occur in 2025.

The *p* and *q* parameters of the Bass diffusion curves were calibrated so that the predicted cumulative adoption from $t_0$ through 2023 was equal to the current market penetration of each technology by state and sector (we fixed the relationship between *p* and *q* at $q = 10p$ to make it possible to solve for p). For technology/state/sectors where there is currently no adoption, we assumed average values for *p* and *q*.

The result of this process was Bass diffusion curves customized for each technology, state, and sector that also accounted for variation in willingness-to-adopt as cost-effectiveness changes over time. The calibrated curves show some segments are still in the very early phases of adoption, while other markets are more mature. Our forecast of annual adoption reflects these differences.

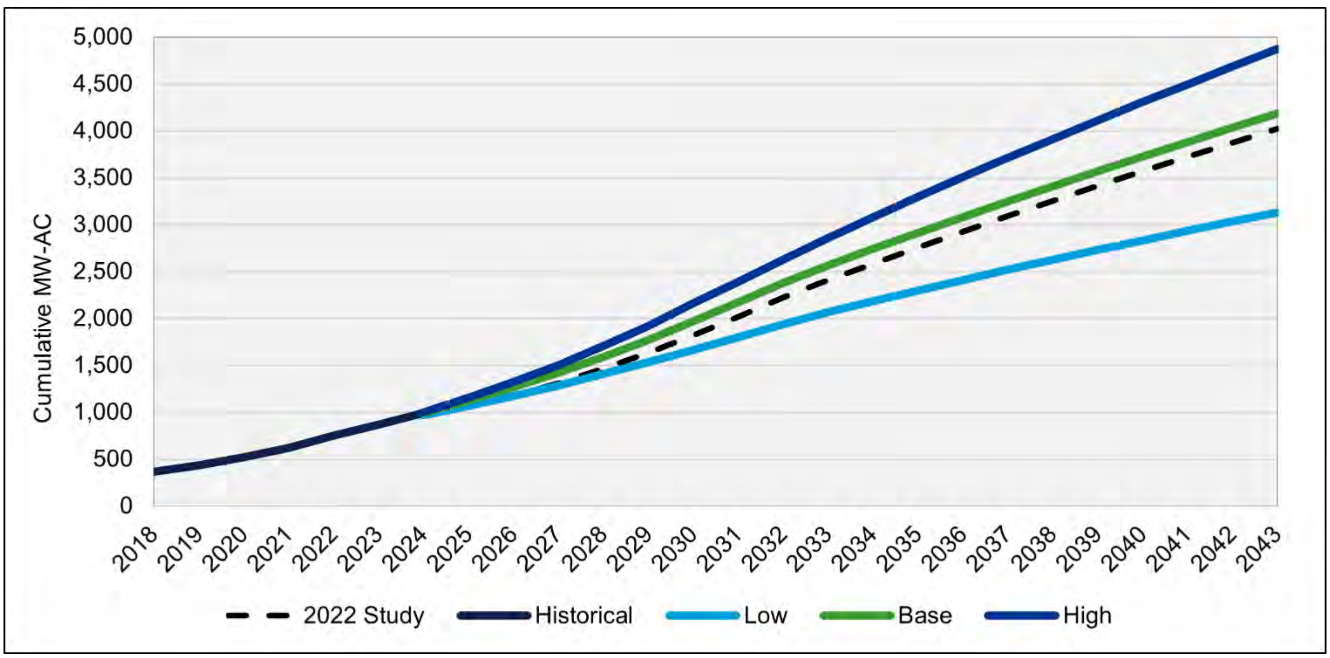
# 4 RESULTS

In the base case scenario (Table 4-1), DNV estimates that 4,182 MW of new distributed generation capacity will be installed in PacifiCorp's service territory over the next twenty years (2024-2043). Figure 4-1 shows the relationship between the base case and low and high case scenarios. The low-case scenario estimates 3,129 MW of new capacity over the 20-year forecast period—compared to the base case, retail rates increase at a slower rate, and technology costs decrease at a slower rate. In the high case, retail rates increase at a faster rate, and technology costs decrease at a faster rate; this results in 4,871 MW of new distributed generation capacity installed by 2043.

**Table 4-1. Cumulative adopted distributed generation capacity by 2043, by scenario**

| Scenario | Cumulative capacity (2043 MW-AC) |
|---|---:|
| **High** | 4,871 |
| **Base** | 4,182 |
| **Low** | 3,129 |

**Figure 4-1. Cumulative new distributed generation capacity installed by scenario (MW-AC), 2018-2043**




The sensitivity analysis showed a greater margin of uncertainty on the low side than on the high side. The IRA extends tax credits for distributed generation that create favorable economics for adoption, and those are embedded in the base case. We therefore limited our upper bound forecast to lower technology costs and higher retail electricity rates, and these produced only a small boost to adoption for technologies that were already cost-effective under the IRA. In contrast, when we modeled our lower bound, we found that the decreases in cost-effectiveness were enough to tamp down adoption. The low case assumed higher technology costs and lower retail electricity rates than the other cases, reducing the economic appeal of distributed generation despite incentives being unchanged. The low-case forecast is 25% less than the base case, while the high-case cumulative installed capacity forecasted over the 20-year period is just 15% greater than the base case.

**Figure 4-2. Cumulative new capacity installed by technology (MW-AC), 2024-2043, base case**

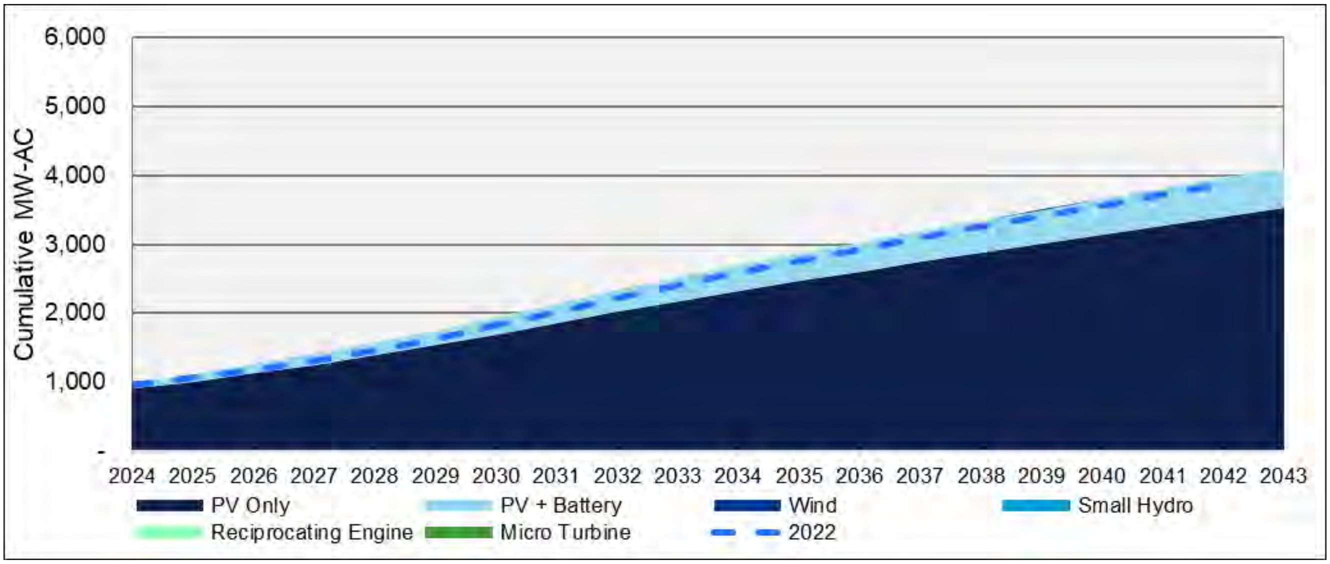



**Figure 4-3. Cumulative new capacity installed by technology (MW-AC), 2024-2043, low case**

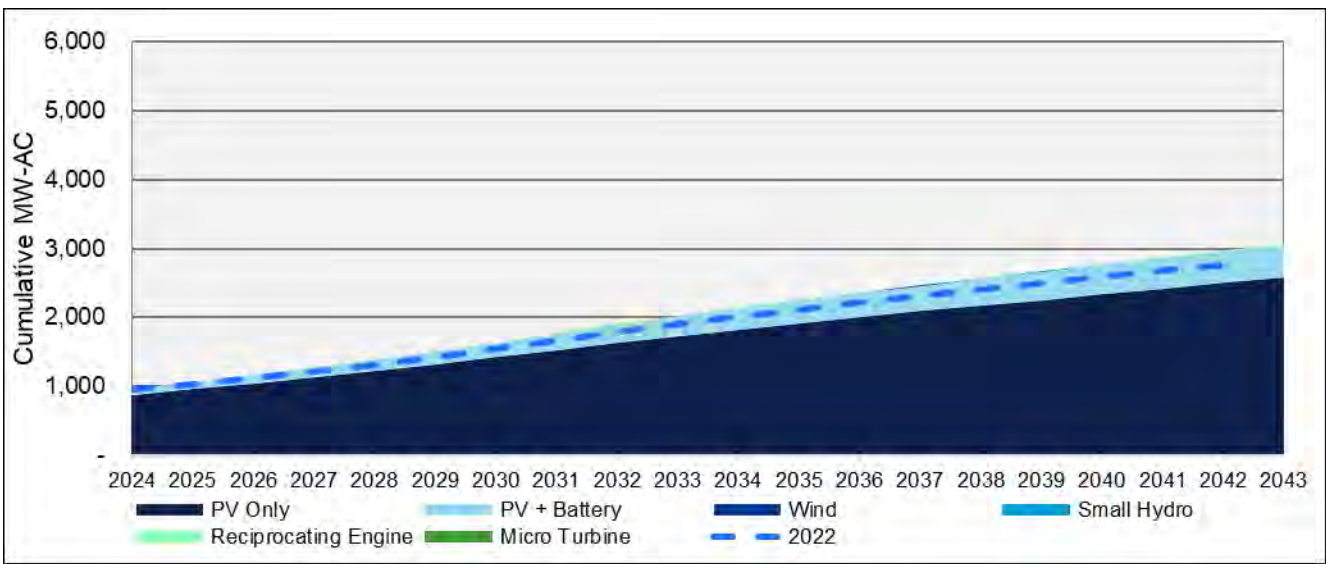
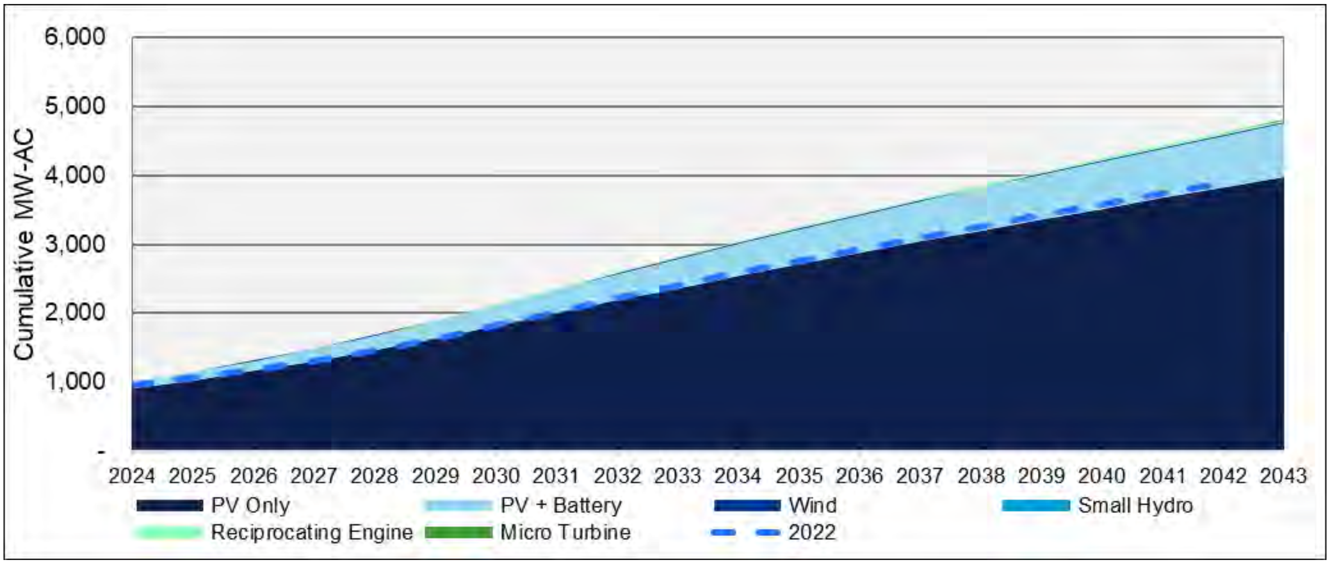


**Figure 4-4. Cumulative new capacity installed by technology (MW-AC), 2024-2043, high case**




The majority of historical and new capacity in all scenarios is either solar PV or solar PV + battery storage. Therefore, the following three charts highlight other technologies (wind and CHP) forecasted adoption by scenario. The high scenario adoption is significantly higher than both the base scenario and low scenario compared to the charts with all technologies (solar PV or solar PV + battery storage included). This is largely due to the influence of more influential adoption parameters having a greater effect in the high scenario compared to the base and low scenarios.

**Figure 4-5. Cumulative new capacity installed by technology (MW-AC), 2024-2043, base case (Excluding PV & PV + Battery)**

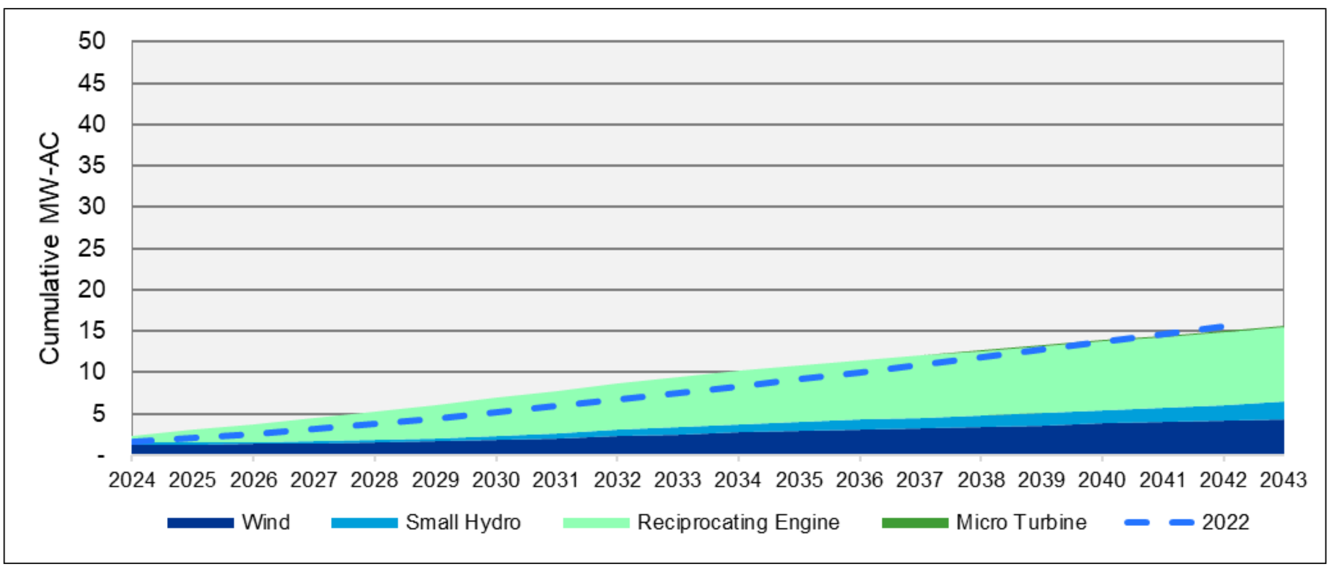


**Figure 4-6. Cumulative new capacity installed by technology (MW-AC), 2024-2043, low case (Excluding PV & PV + Battery)**

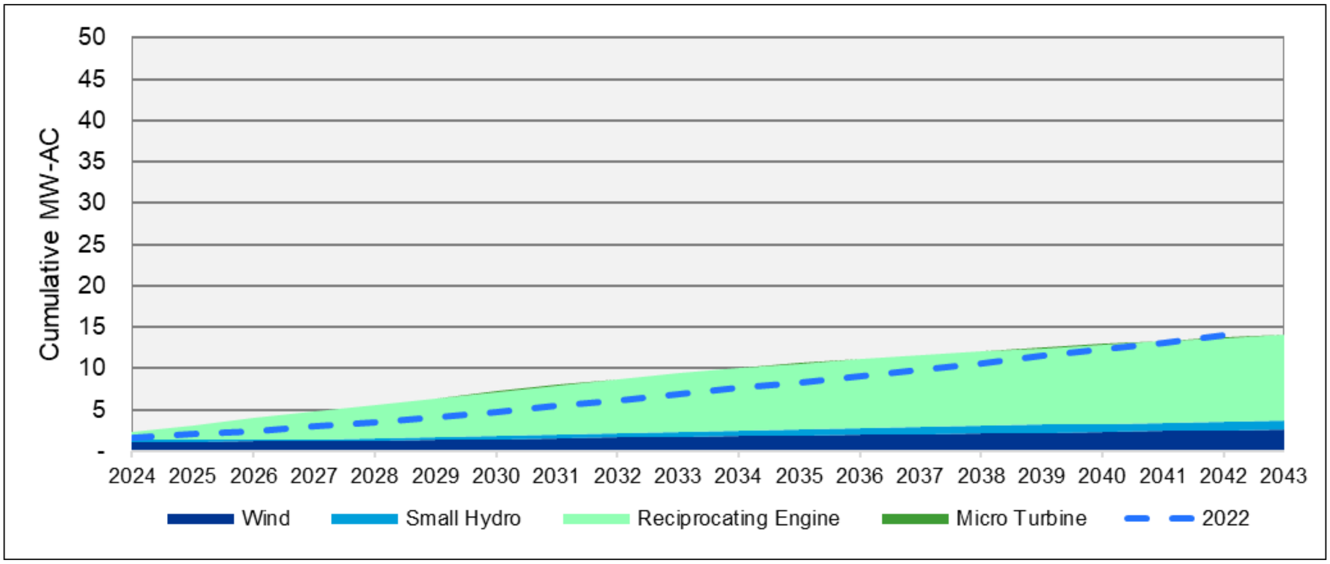
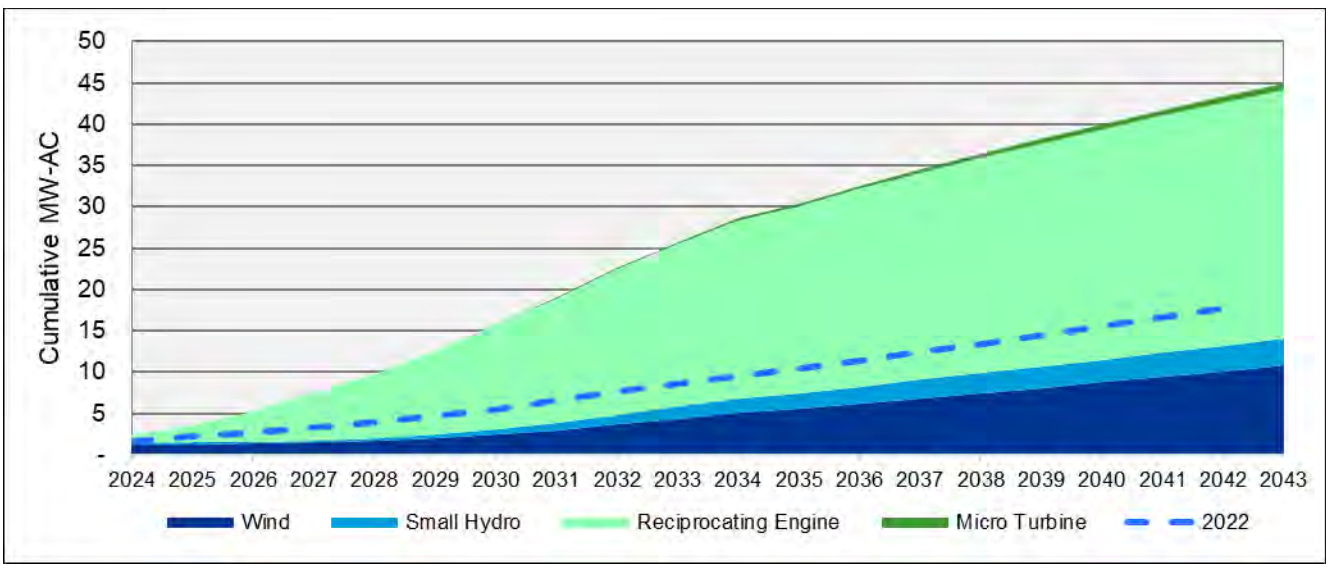



**Figure 4-7. Cumulative new capacity installed by technology (MW-AC), 2024-2043, high case (Excluding PV & PV + Battery)**

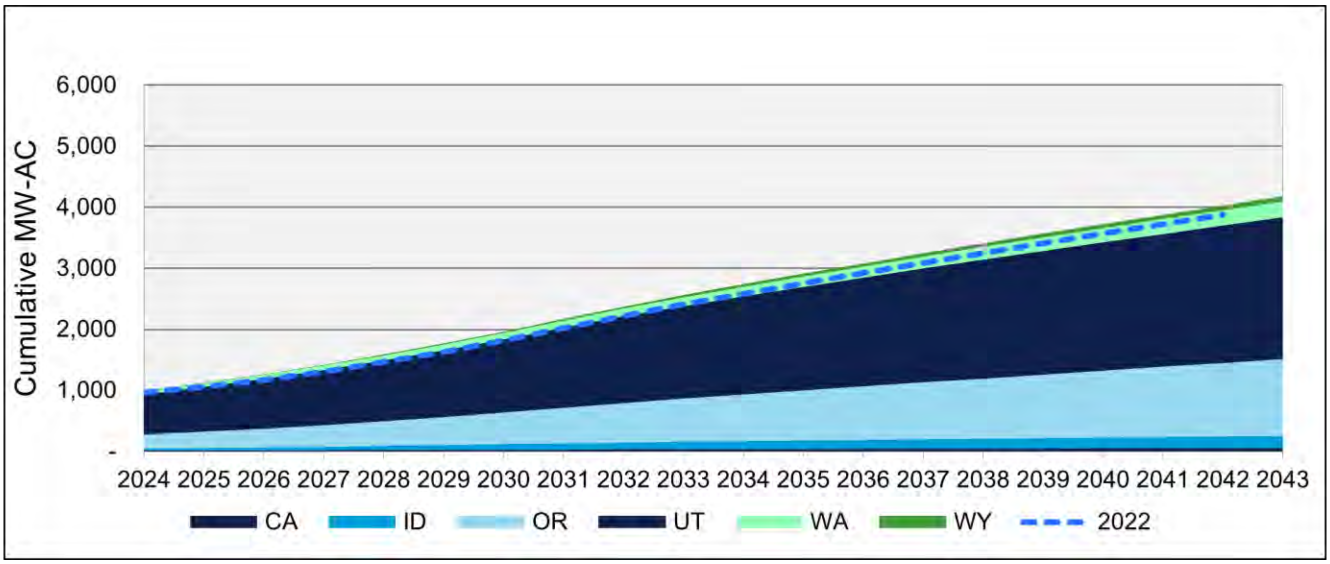



## 4.1 Generation capacity results by state

The following sections present the results by state for each forecast scenario. Additional exhibits for total PV capacity forecasted are provided by sector. PV Only and PV + Battery capacity make up at least 95% of each state's projected distributed generation capacity, so providing results for the other technologies by sector would not provide useful context to the results. The full set of results by state, sector, and new/existing construction for the forecasts is provided in Appendix B, section 5.2.

Figure 4-8 shows the base case forecast by state, compared to the previous (2022) study's total base case forecast. This figure indicates that Utah and Oregon will drive the most distributed generation installations over the next two decades, which is to be expected given these two states represent the largest share of PacifiCorp's customers and sales. The base scenario estimates approximately 2,567 MW of new capacity will be installed over the next 10 years in PacifiCorp's territory—59% of which is in Utah, 28% in Oregon, and 5% in Idaho. Since the 2022 study, the federal ITC has been extended for ten years at its original base rate levels and expanded to include energy storage. The tax credit increase and extension lowered the customer payback period for all technologies, making the customer economics of this study's base case more similar to the previous study's high case. In addition to the change in customer economics, projected PV capacity is expected to grow at a faster rate in the early years and at a slower rate towards the end of the forecast period. The key drivers of these differences include larger average PV system sizes, decreases in PV + Battery costs, and the maturity of rooftop PV technology. The adoption model DNV developed for this study was calibrated to existing levels of technology adoption for each state and sector. Technology adoption follows an S-curve with adoption initially increasing at an increasing rate, but eventually passing an inflection point where adoption continues to increase at a decreasing rate.

**Figure 4-8. Cumulative new capacity installations by state (MW-AC), 2024-2043, base case**




## 4.1.1 California

Customers in PacifiCorp's service territory in northern California are projected to install about 60 MW of new distributed generation capacity or ~3,000 new customers over the next two decades in the base case. The 20-year high projection is about 15% greater than the base case and the low projection is 10% less than the base case, or 71 MW and 55 MW, respectively.

California does not currently have any state incentives available for distributed generation and uses a net billing structure for DER compensation. The residential sector has the largest share of the distributed generation capacity, ranging from 49% in the low case to 38% in the high and base cases. The next largest share of the capacity is forecasted in the commercial sector, ranging from 36% in the low case to 36% in the base and high cases.

**Figure 4-9. Cumulative new distributed generation capacity installations by scenario (MW-AC), California, 2018-2043**

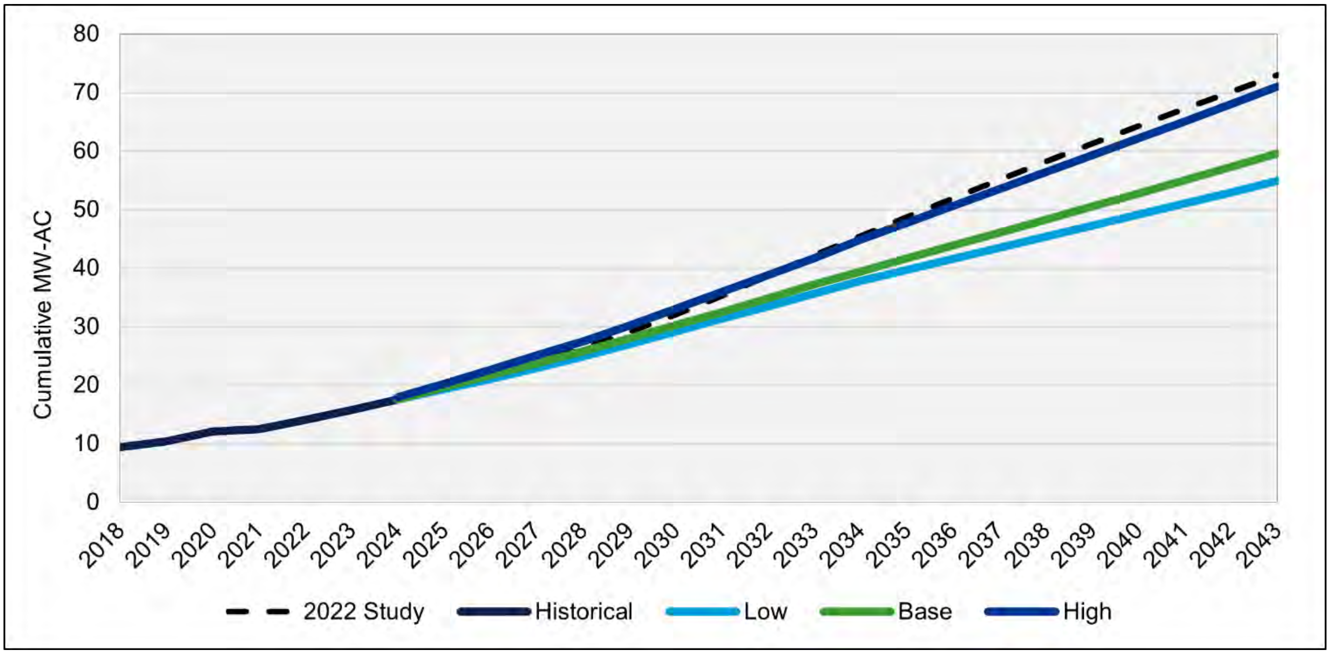



**Figure 4-10. Cumulative new capacity installations by technology (MW-AC), California base case, 2024-2043**

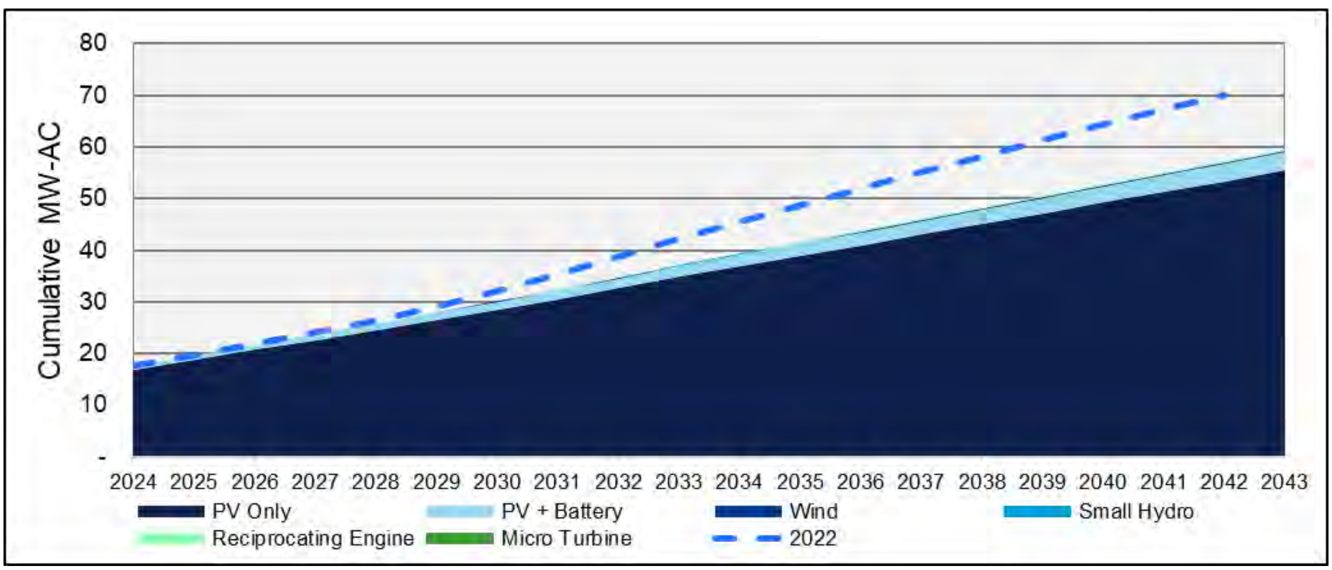


**Figure 4-11. Cumulative new capacity installations by technology (MW-AC), California low case, 2024-2043**

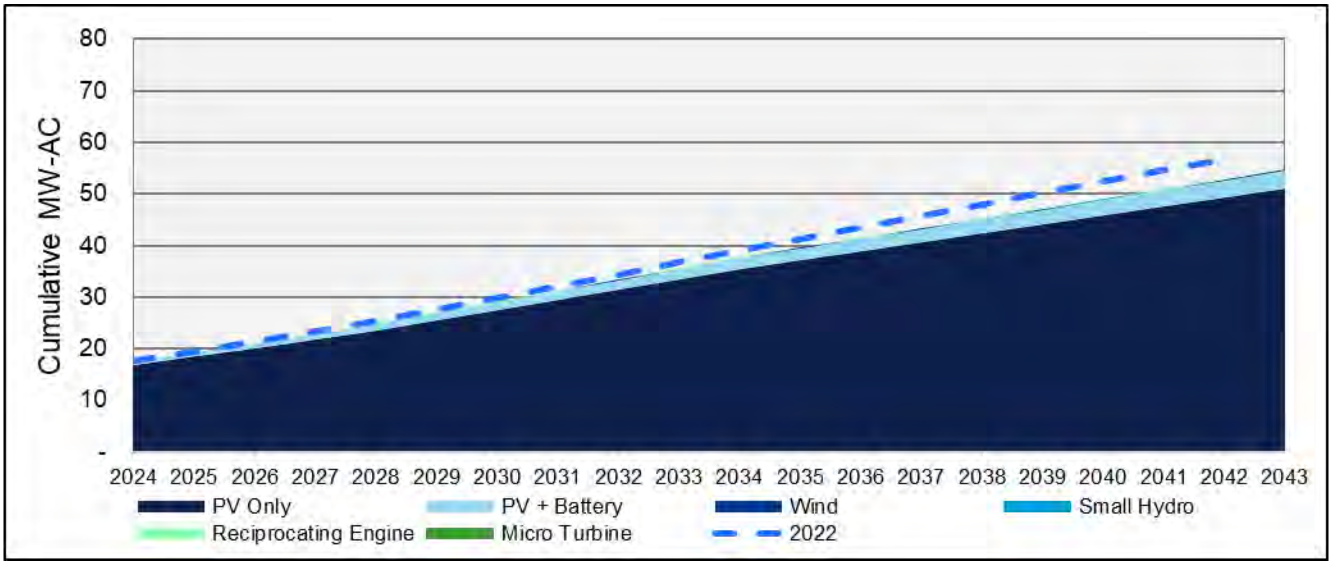
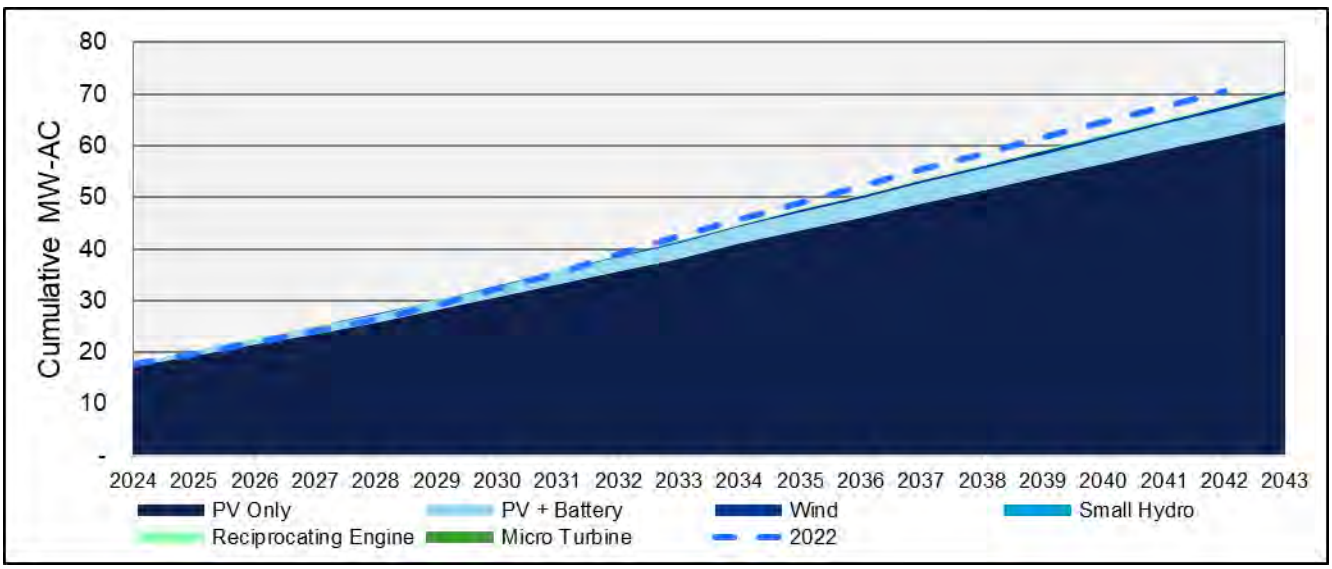



**Figure 4-12. Cumulative new capacity installed by technology (MW-AC), California high case, 2024-2043**

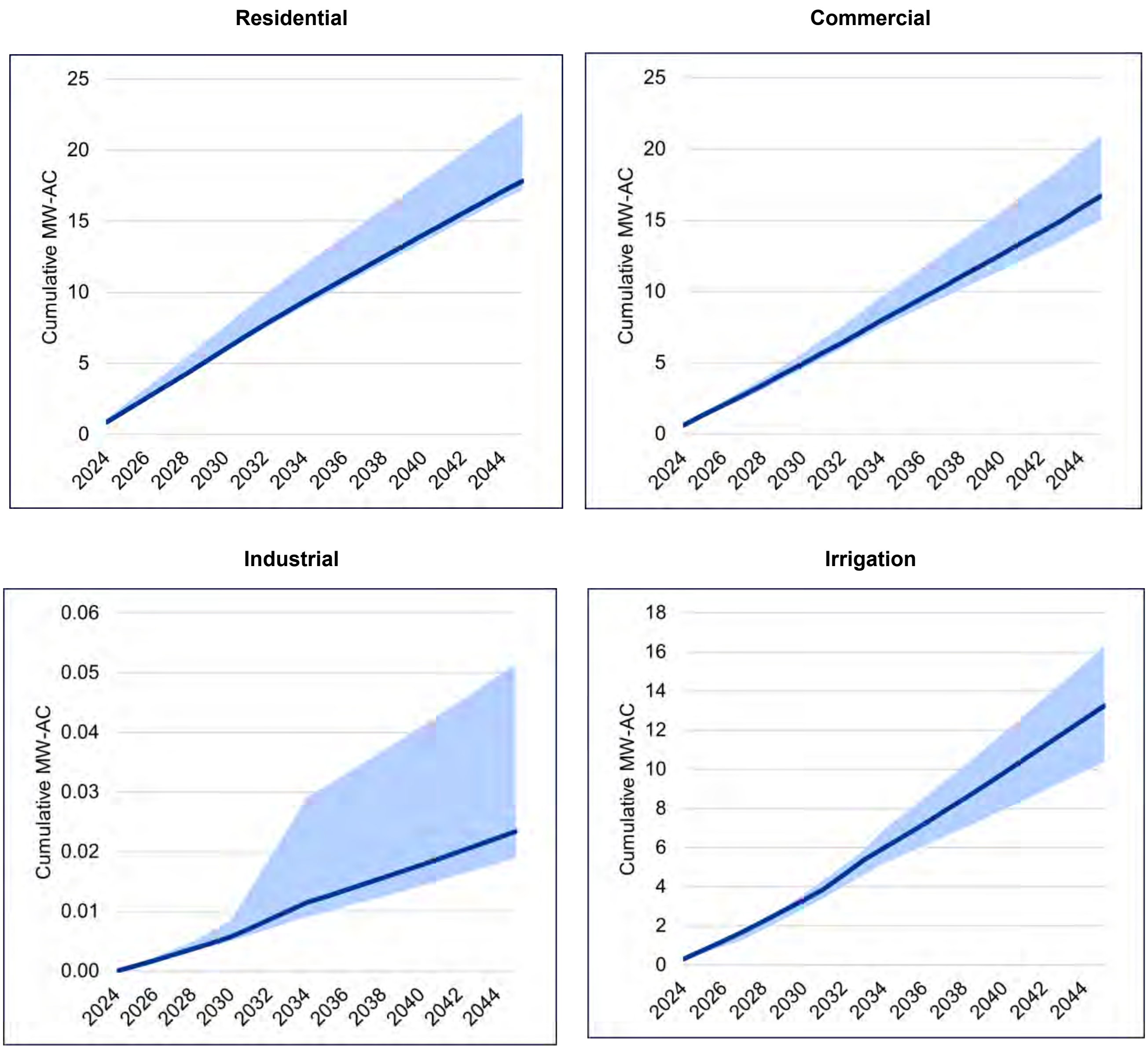


#### 4.1.1.1 California PV adoption by sector

The impact of the three different scenarios on PV adoption by sector is shown in Figure 4-13, which presents the differences in PV capacity relative to the base case for the three modeled scenarios across the four sectors. In the residential sector, the share of PV + Battery capacity is about 6% of total PV capacity in 2043 for the high case. The share of PV + Battery capacity is about 20% of total commercial PV capacity in 2043 for the high case. The irrigation sector has a similar portion of its PV capacity in PV + Battery configurations, at 14% of total capacity in the high case.

**Figure 4-13. Cumulative new PV capacity installed by sector across all scenarios, California, 2024-2043**

*Upper and lower bounds (in blue) represent the high and low case forecasts, with a line for the base case.*



## 4.1.2 Idaho

PacifiCorp's customers in Idaho are projected to install about 167 MW of new distributed generation capacity or ~15,500 new customers over the next two decades in the base case. The 20-year high projection is about 20% greater than the base case, and the low projection is 36% less than the base case, or 247 MW and 127 MW, respectively.

Idaho has an incentive program for residential customers that boosted the sector's adoption, compared to the other sectors. The incentives are provided through the Residential Alternative Energy Income Tax Deduction, discussed in section 3.1.6. DNV assumed Idaho would use the same net billing structure for DER compensation as Utah for the study period (2024-2043). The residential sector has the largest share of the distributed generation capacity, ranging from 59% in the base and 61% in the high case to 57% in the low case. The next largest share of the capacity is forecasted in the commercial sector, ranging from 31% in the low and base cases to 26% in the high case.

**Figure 4-14. Cumulative new distributed generation capacity installed by scenario (MW-AC), Idaho, 2018-2043**

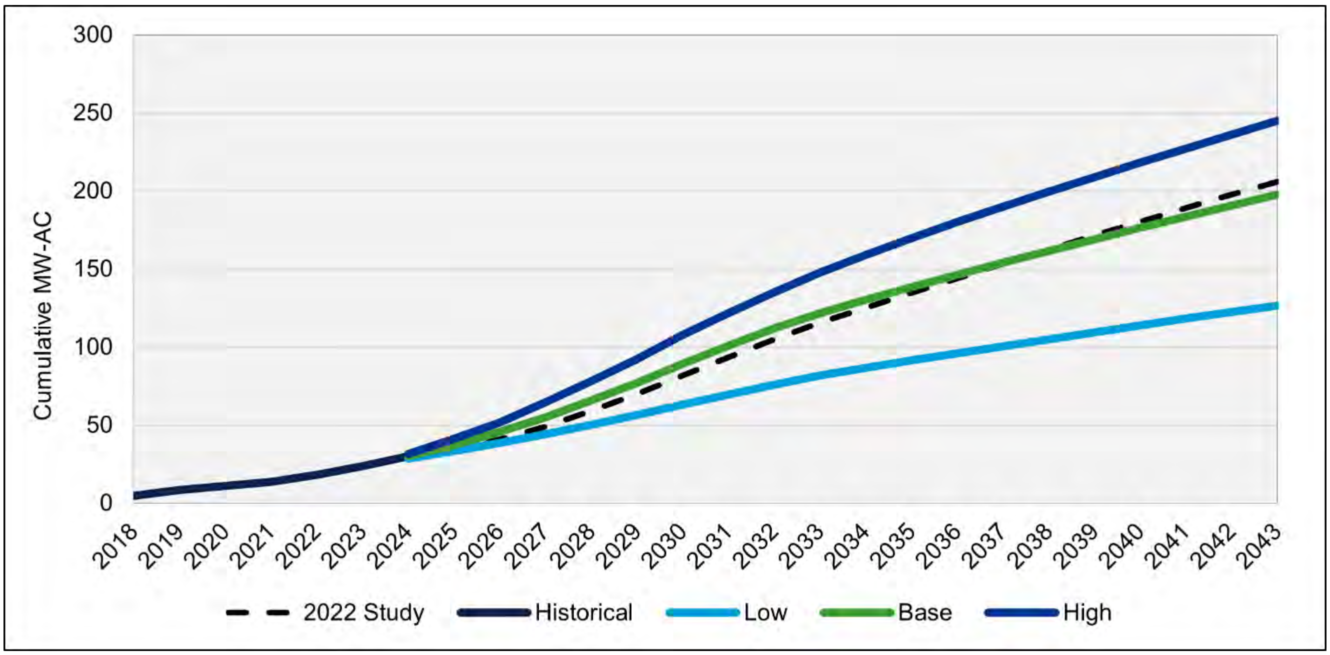


**Figure 4-15. Cumulative new capacity installations by technology (MW-AC), Idaho base case, 2024-2043**

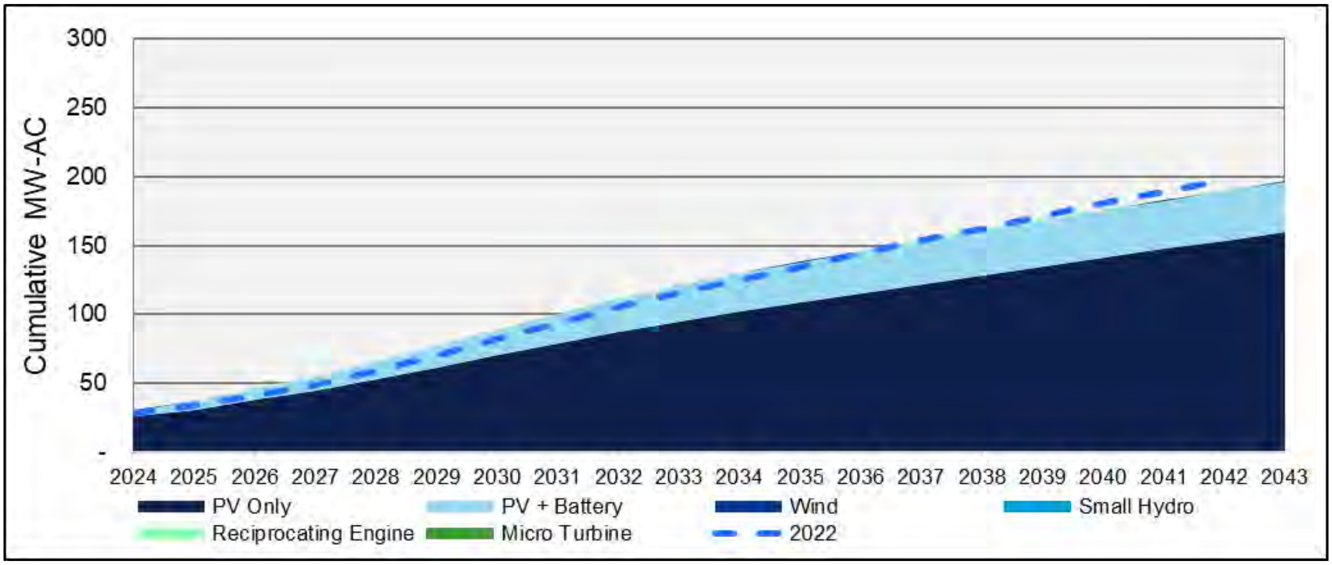



**Figure 4-16. Cumulative new capacity installations by technology (MW-AC), Idaho low case, 2024-2043**

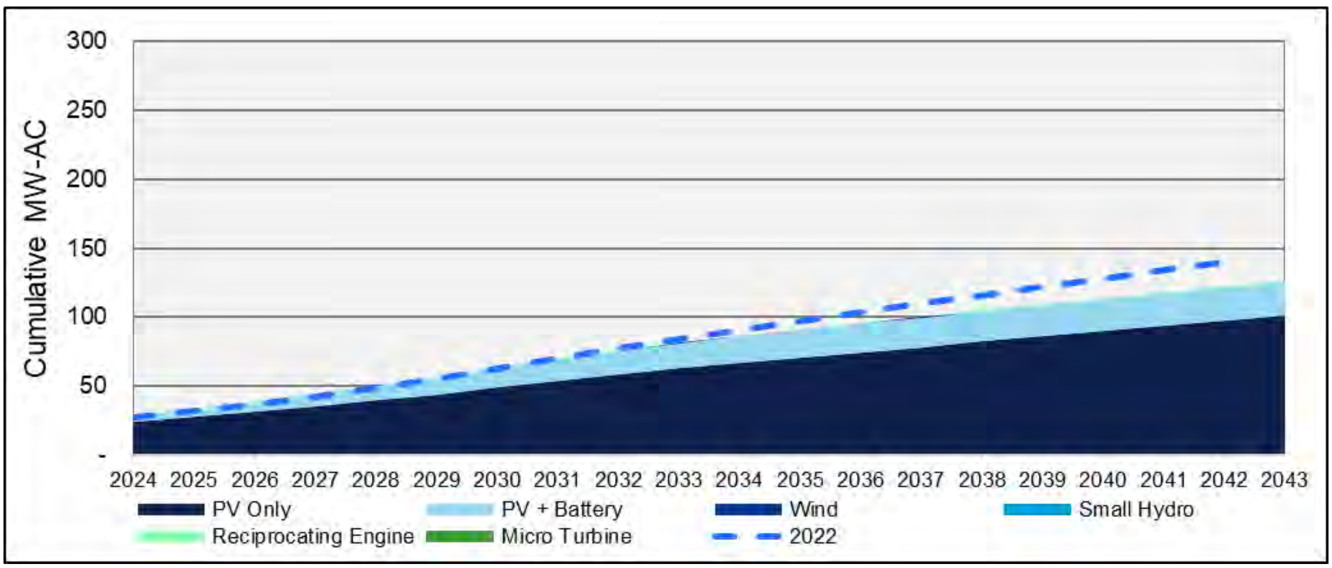
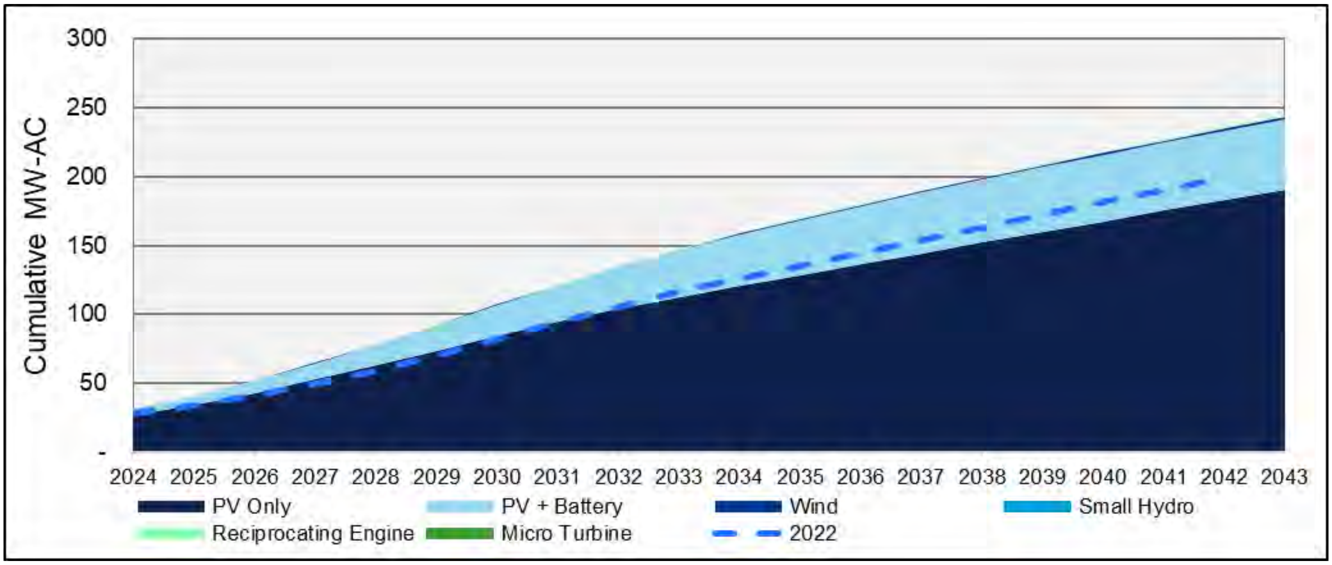


**Figure 4-17. Cumulative new capacity installations by technology (MW-AC), Idaho high case, 2024-2043**

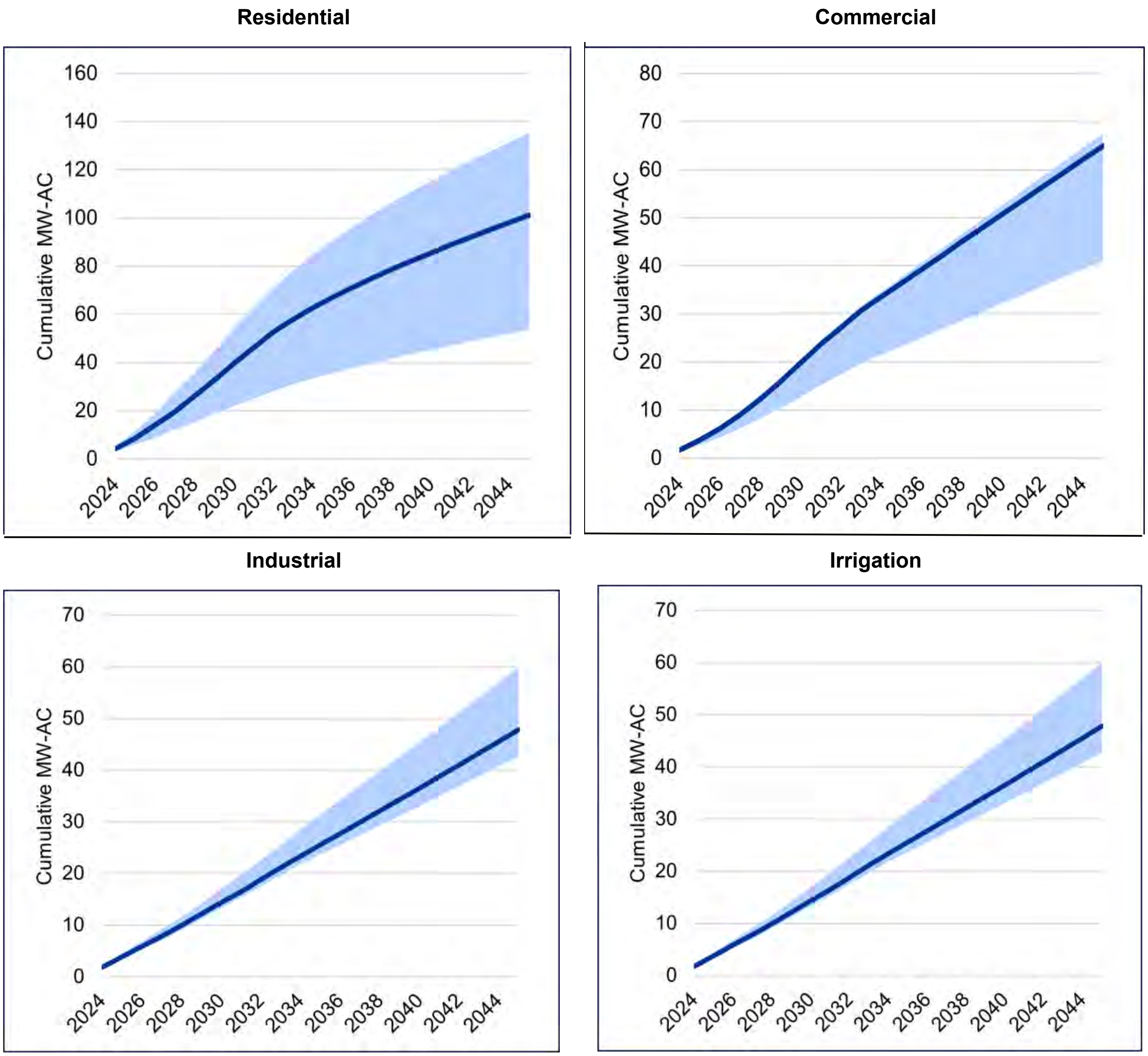


#### 4.1.2.1 Idaho PV adoption by sector

The differences in PV capacity relative to the base case for the three modeled scenarios across the four sectors are presented in the following charts. In the residential sector, the high case share of PV + Battery capacity is about 15% of total residential PV capacity in 2042. The share of PV + Battery capacity is about 8% of total commercial PV capacity in 2042. The irrigation sector has a slightly higher portion of its PV capacity in PV + Battery configurations, at 4% of total capacity. The industrial sector did not have any PV + Battery adoption forecasted.

**Figure 4-18. Cumulative new PV capacity installed by sector across all scenarios, Idaho, 2024-2043**

*Upper and lower bounds (in blue) represent the high and low case forecasts, with a line for the base case.*



## 4.1.3 Oregon

PacifiCorp's customers in Oregon are projected to install about 1,030 MW of new distributed generation capacity or ~119,250 new customers over the next two decades in the base case. The 20-year high projection is 18% higher than the base case and the low projection is 22% less than the base case, or 1,260 MW and 985 MW, respectively.

Oregon has incentives available through the Oregon Department of Energy (DOE) for PV + Battery systems and the Energy Trust of Oregon (ETO) for PV Only configurations. The ETO offers incentives for both residential and business customers, while the Oregon DOE provides incentives for residential customers only. The incentives are discussed further in section 3.1.6. The PV + Battery incentives offered for residential customers by the Oregon DOE provided a boost to customer economics that led to the majority of PV + Battery adoption growth being in the residential sector. The majority of the PV Only adoption growth in the early years of the forecast is in the commercial sector, with the residential sector following closely behind and eventually overtaking the forecast in the later years. Oregon's net metering policies were assumed to stay in place throughout the study, providing more favorable economics for PV Only compared to PV + Battery systems.

**Figure 4-19. Cumulative new distributed generation capacity installed by scenario (MW-AC), Oregon, 2018-2043**

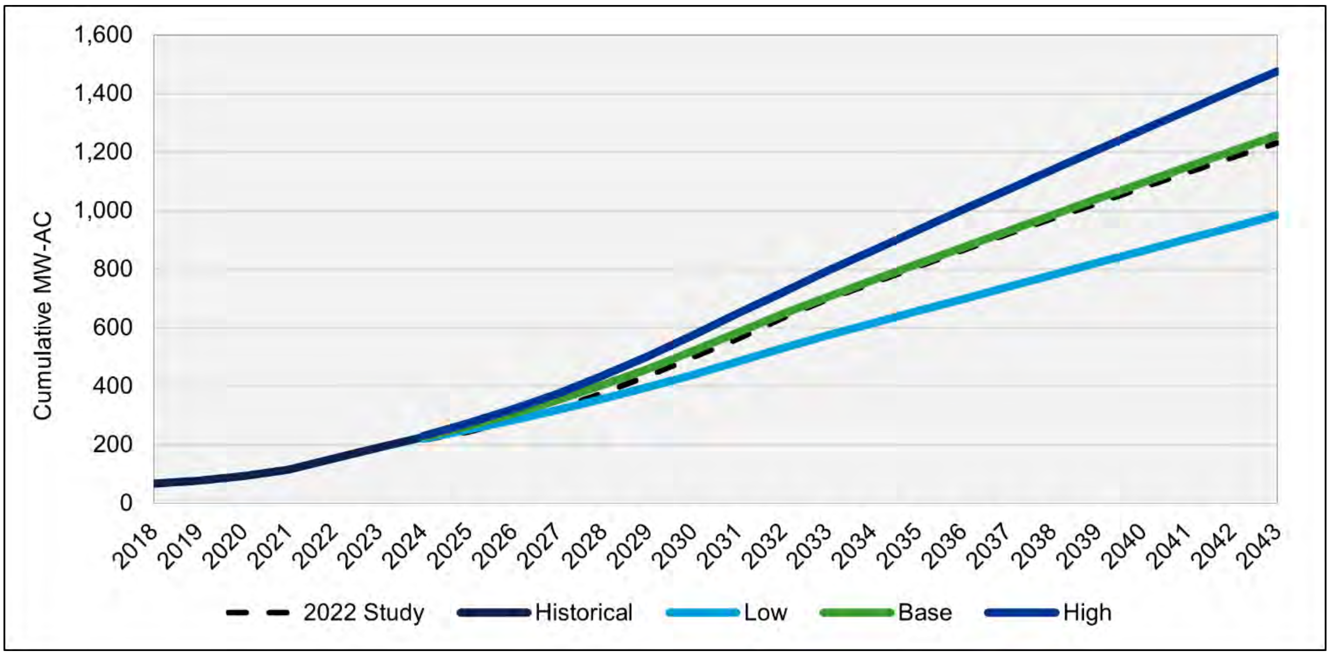


**Figure 4-20. Cumulative new capacity installations by technology (MW-AC), Oregon base case, 2024-2043**

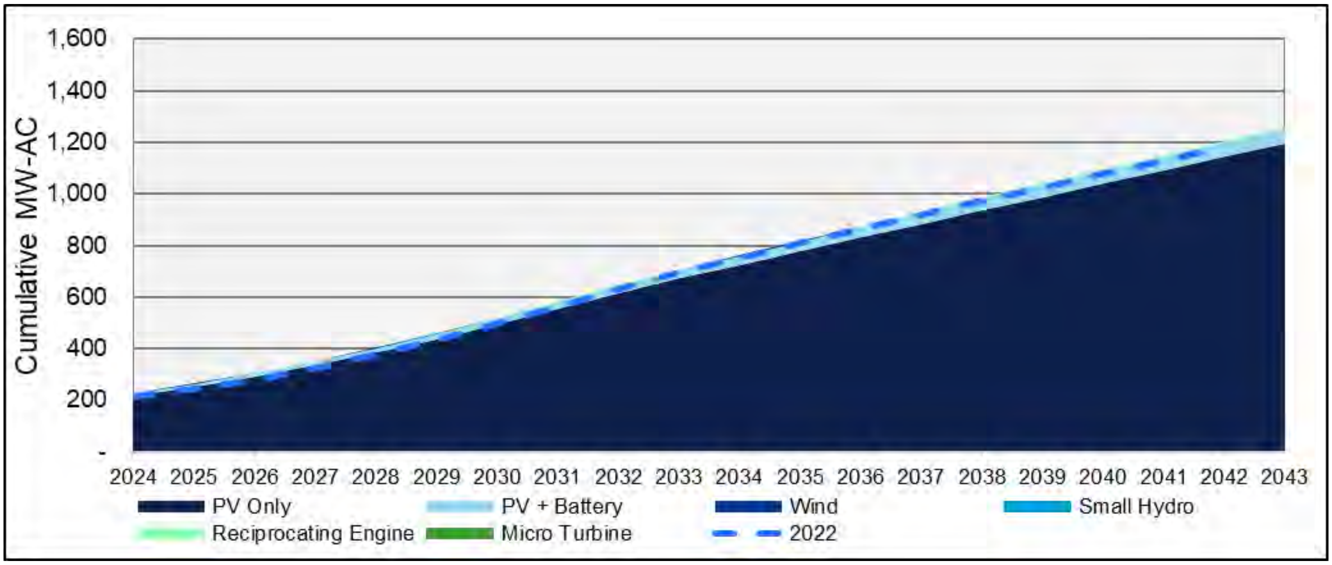



**Figure 4-21. Cumulative new capacity installations by technology (MW-AC), Oregon low case, 2024-2043**

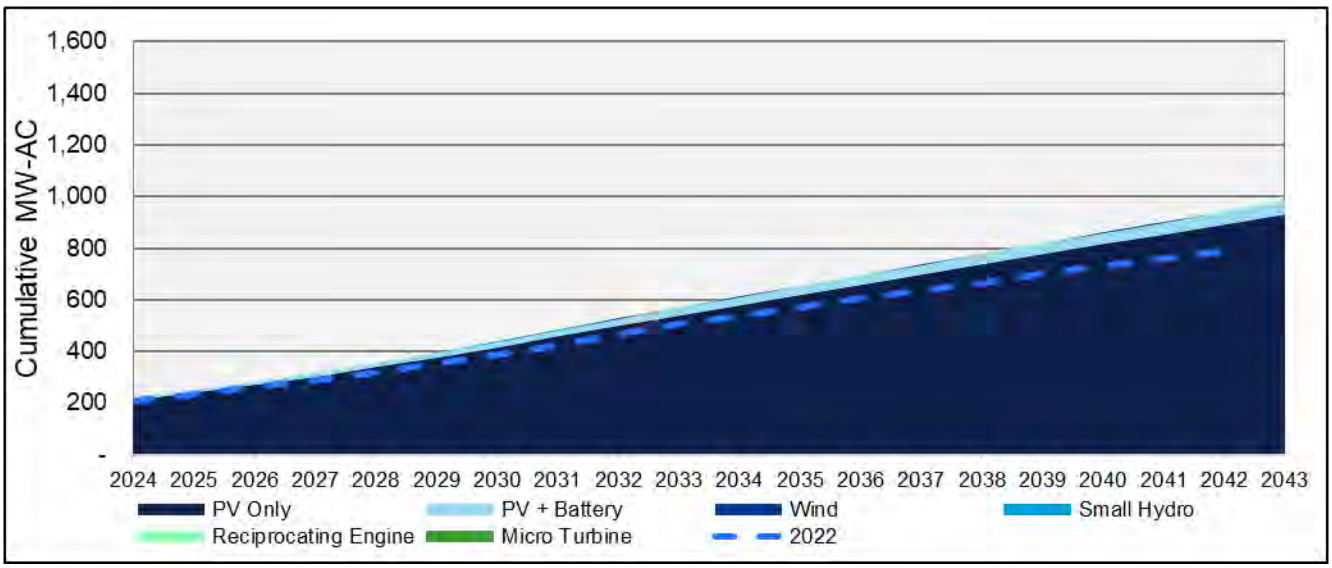
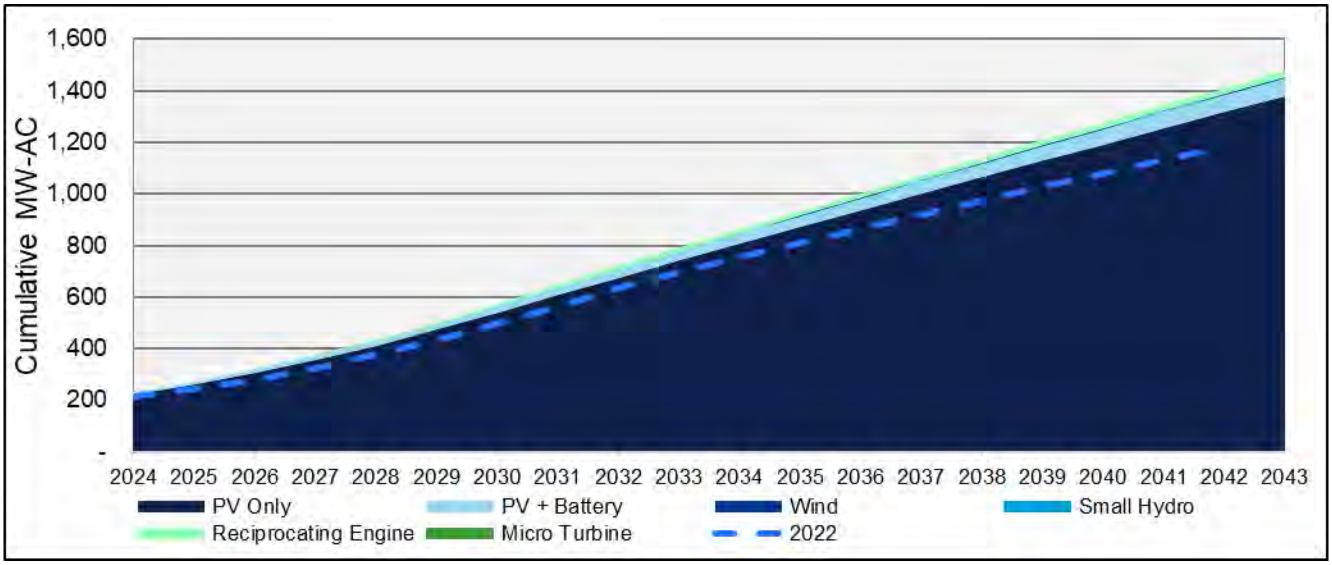


**Figure 4-22. Cumulative new capacity installations by technology (MW-AC), Oregon high case, 2024-2043**

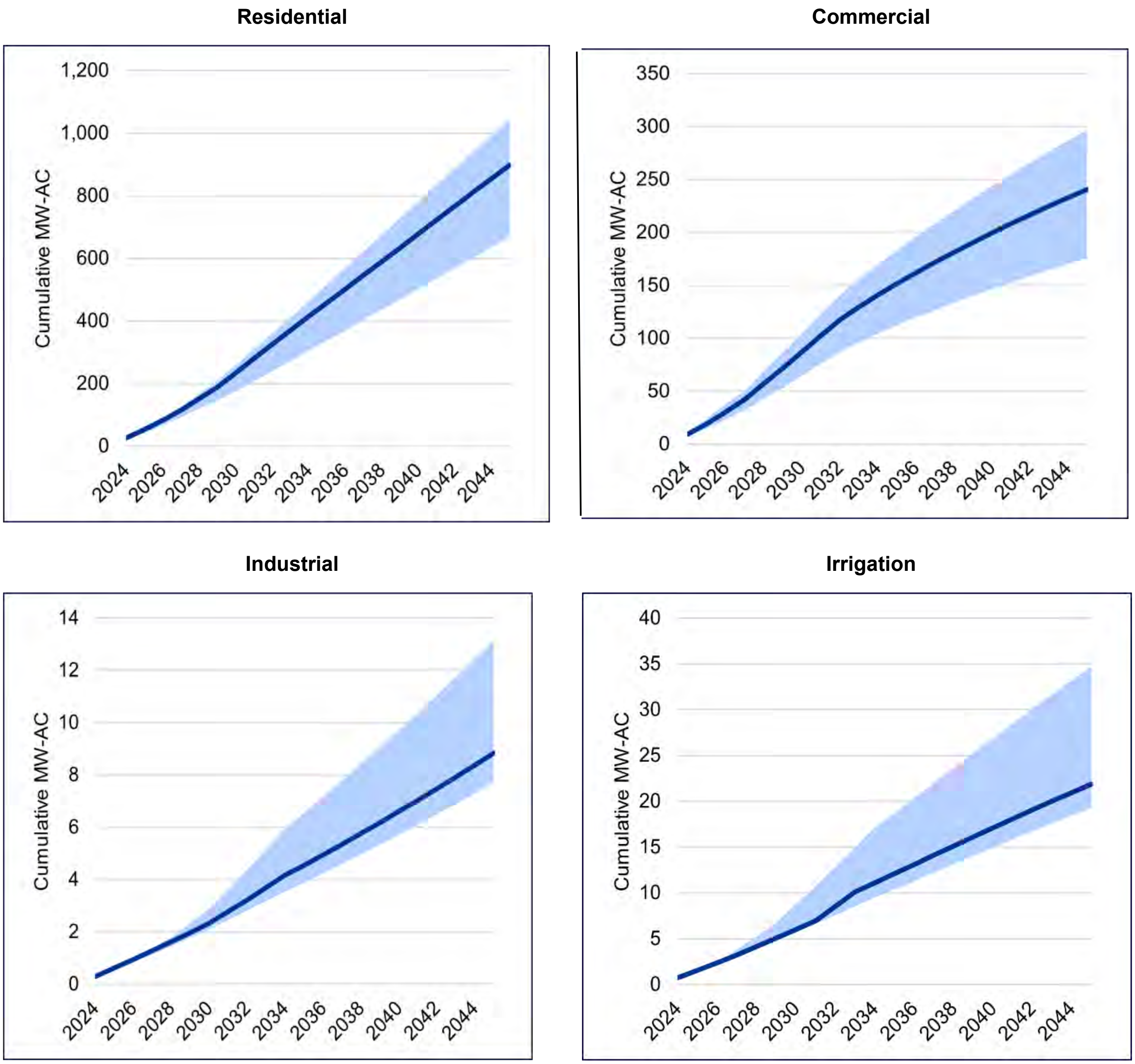


### 4.1.3.1 Oregon PV adoption by sector

The differences in PV capacity relative to the base case for the three modeled scenarios across the four sectors are presented in the following charts. In the residential sector, the share of PV + Battery capacity is about 4% of total residential PV capacity in 2042. The share of PV + Battery capacity is about 2% of total commercial PV capacity in 2042. The irrigation sector has a similar portion of its PV capacity in PV + Battery configurations, at 3% of total capacity. The industrial sector had a smaller share of its PV capacity in PV + Battery configurations at less than 1%.

**Figure 4-23. Cumulative new PV capacity installed by sector across all scenarios, Oregon, 2024-2043**

*Upper and lower bounds (in blue) represent the high and low case forecasts, with a line for the base case.*



### 4.1.4 Utah

PacifiCorp's customers in Utah are projected to install about 1,653 MW of new distributed generation capacity or ~127,000 new customers over the next two decades in the base case. The 20-year high projection is 11% greater than the base case and the low projection is 25% less than the base case, or 2,596 MW and 1,733 MW, respectively.

Utah has an incentive program for residential and business customers, but the residential PV-only incentive expired in 2023. The remaining incentives are provided through the Utah Office of Energy Development Renewable Energy Systems Tax Credit, discussed in section 3.1.6. DNV assumed Utah's net billing policies would remain in place throughout the study. In all cases, the residential sector has the largest share of the distributed generation capacity forecasted—ranging from 56% to 61% in the high and low cases, respectively. The commercial sector represents 40% of the capacity forecast in the high and 42% in the base scenarios, but only 36% in the low case.

**Figure 4-24. Cumulative new distributed generation capacity installed by scenario (MW-AC), Utah, 2023-2043**

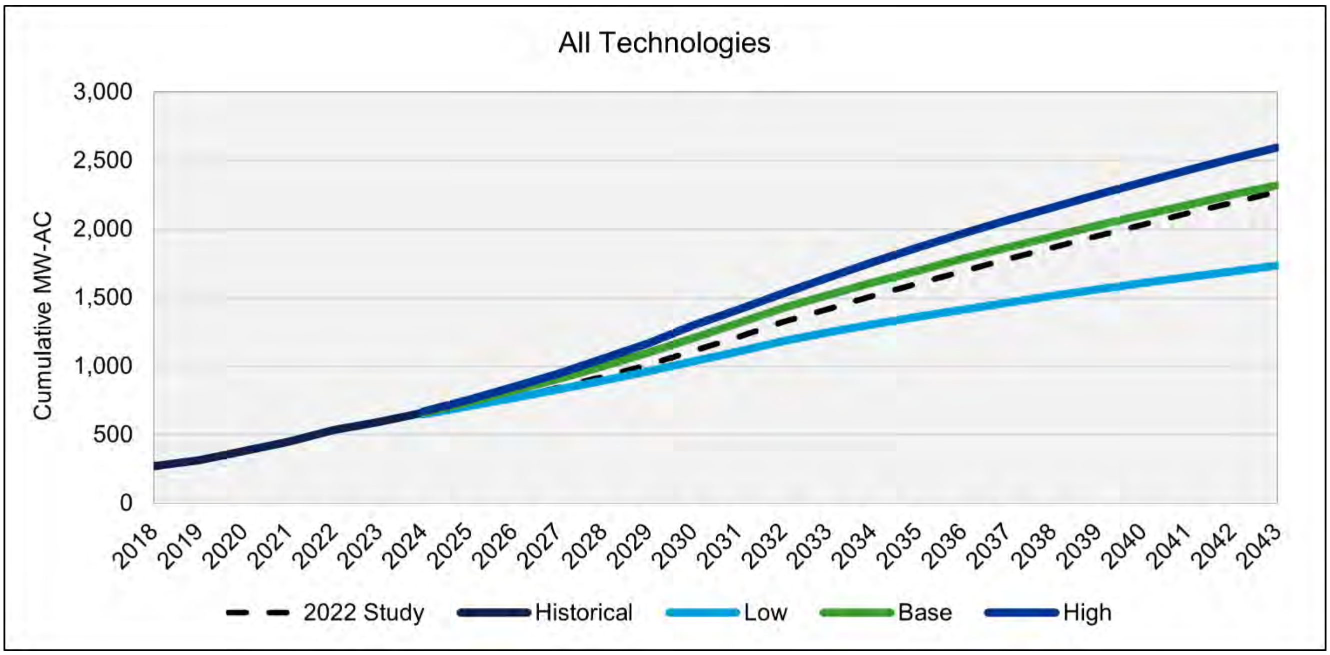


Figure 4-25. Cumulative new capacity installations by technology (MW-AC), Utah base case, 2024-2043

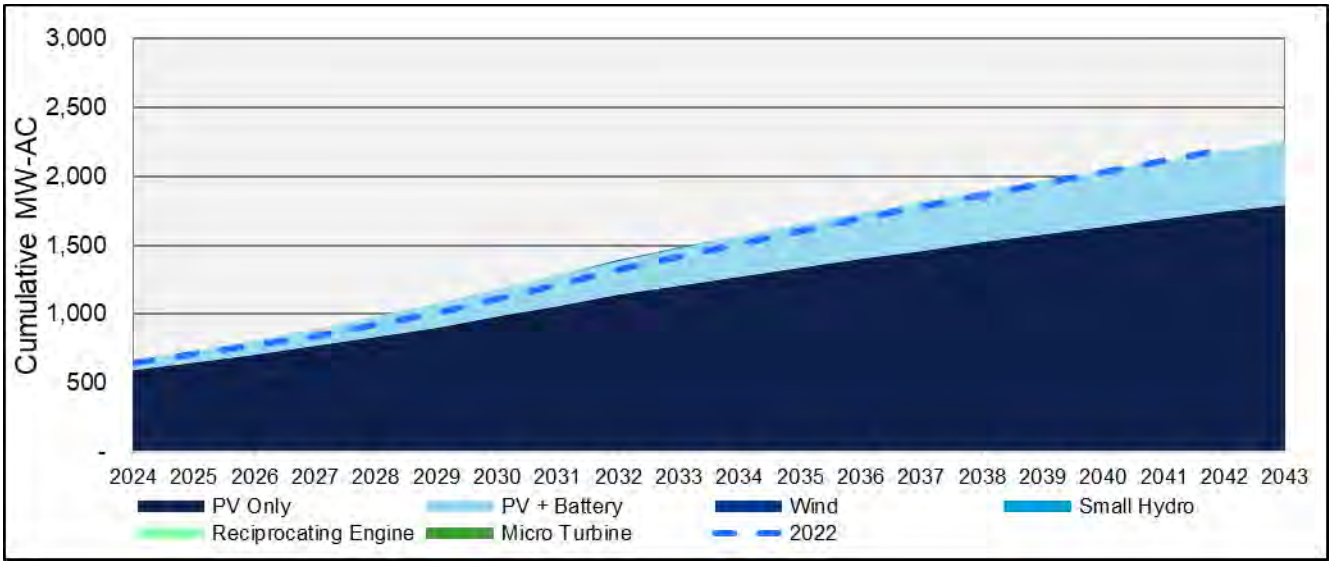



Figure 4-26. Cumulative new capacity installations by technology (MW-AC), Utah low case, 2024-2043

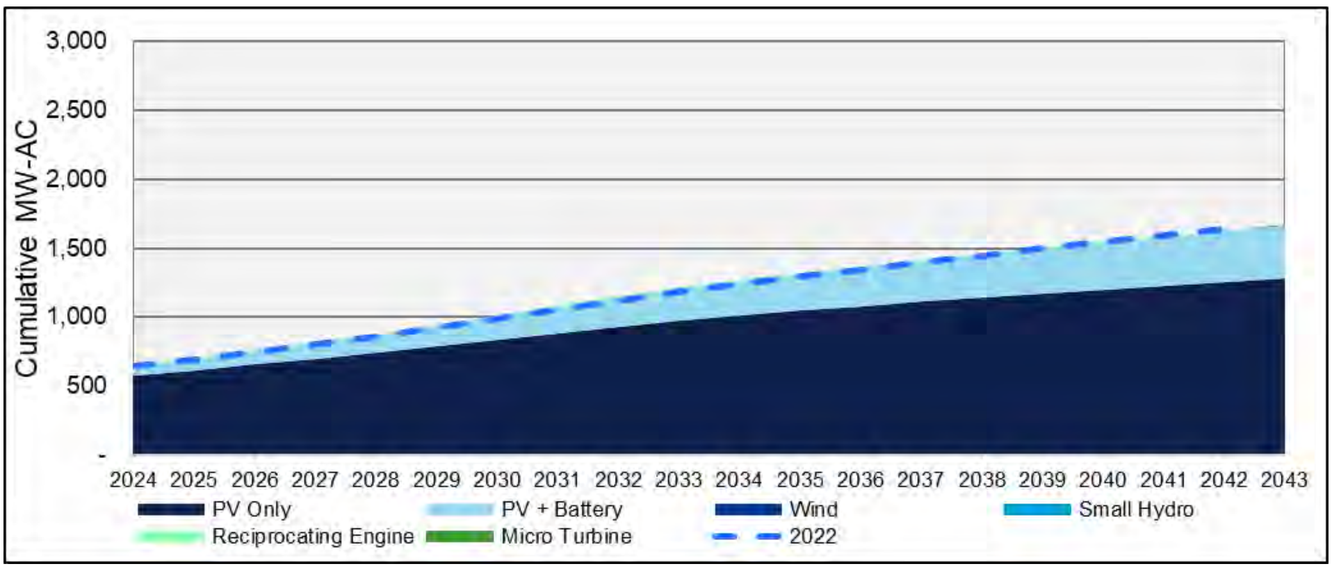
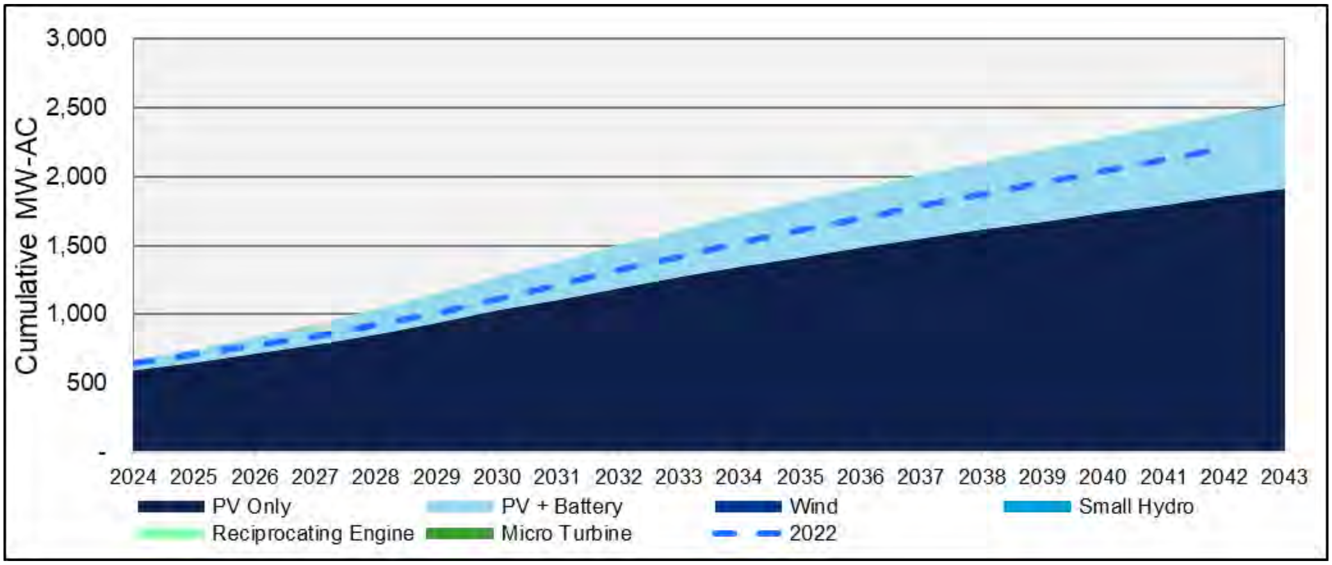


**Figure 4-27. Cumulative new capacity installations by technology (MW-AC), Utah high case, 2024-2043**

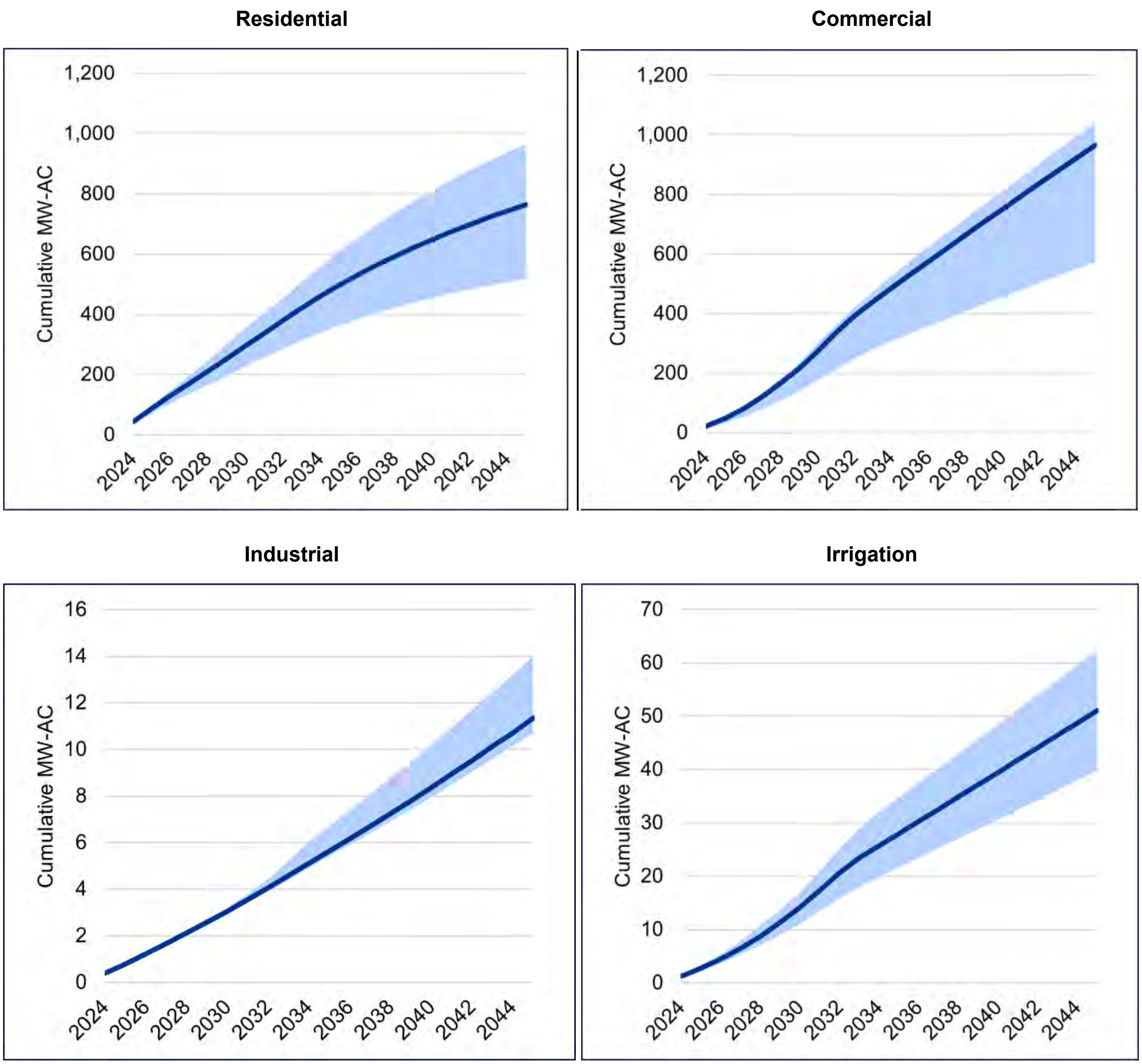


### 4.1.4.1 Utah PV adoption by sector

The differences in PV capacity relative to the base case for the three modeled scenarios across the four sectors are presented in the following charts. In the residential sector, the share of PV + Battery capacity is between 28 and 32% of total residential PV capacity in 2042. The share of PV + Battery capacity is about 4% of total commercial PV capacity in 2042. The industrial sector has a lower portion of its PV capacity in PV + Battery configurations, at 1% of total capacity. About 5% of the irrigation sector PV capacity forecasted is in a PV + Battery configuration.

**Figure 4-28. Cumulative new PV capacity installed by sector across all scenarios, Utah, 2024-2043**

*Upper and lower bounds (in blue) represent the high and low case forecasts, with a line for the base case.*



## 4.1.5 Washington

PacifiCorp's customers in Washington are projected to install about 218 MW of new distributed generation capacity or ~16,150 new customers over the next two decades in the base case. The 20-year low projection is about 29% less than the base case, or 187 MW. The high case is 25% higher than the base case, or 351 MW, as seen in

Figure 4-29.

Washington state currently offers no incentives for distributed generation technologies. The residential sector has the largest share of the distributed generation capacity, ranging from 66% in the high case, 68% in the base case, and 70% in the low case. The next largest share of the capacity is forecasted in the commercial sector, ranging from 24% in the low case to 27% in the base and high cases. Washington's net metering policies were assumed to stay in place throughout the assessment, providing more favorable economics for PV Only compared to PV + Battery systems.

**Figure 4-29. Cumulative new distributed generation capacity installed by scenario (MW-AC), Washington, 2018-2043**

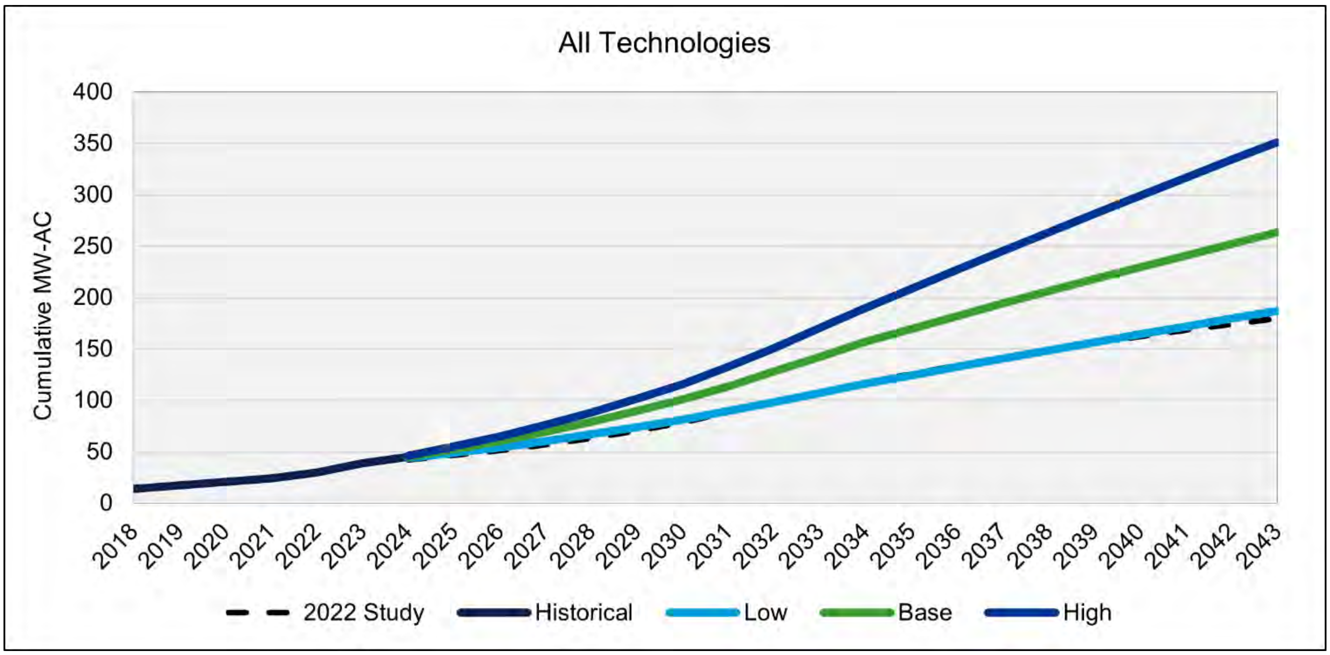


Figure 4-30. Cumulative new capacity installations by technology (MW-AC), Washington base case, 2024-2043

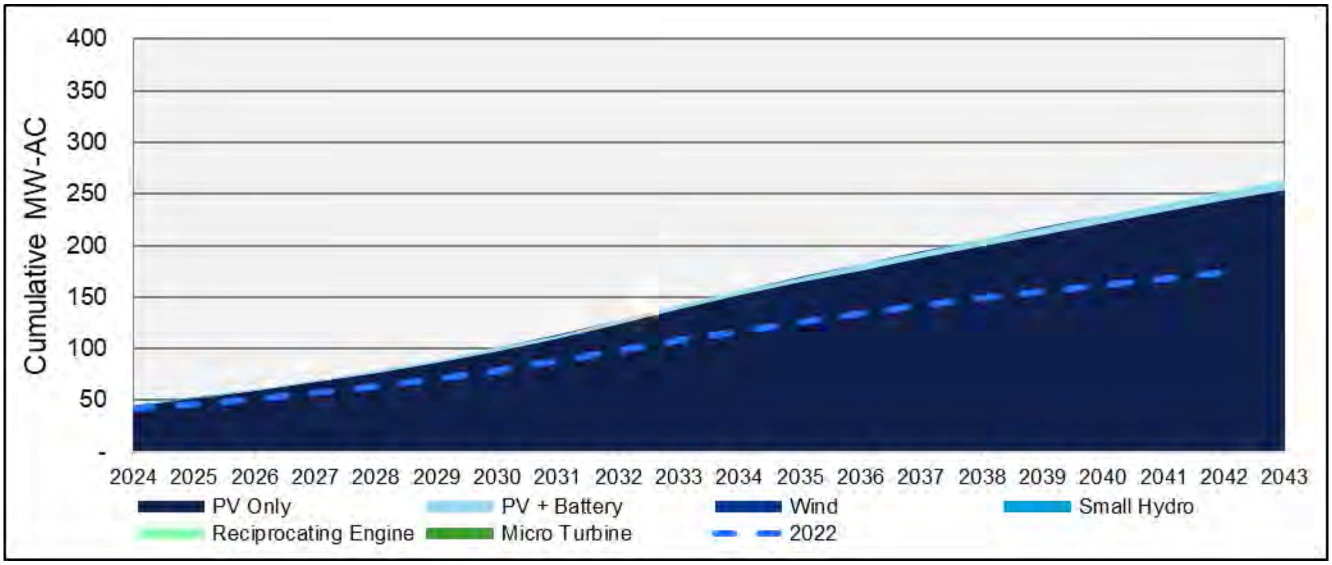



Figure 4-31. Cumulative new capacity installations by technology (MW-AC), Washington low case, 2024-2043

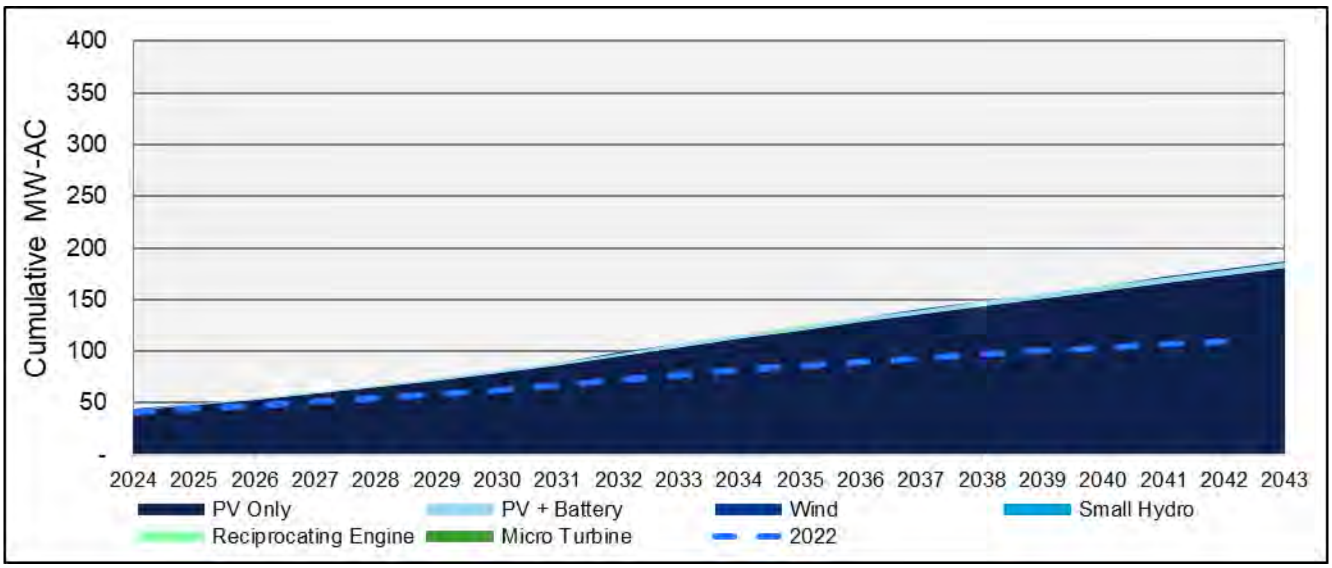
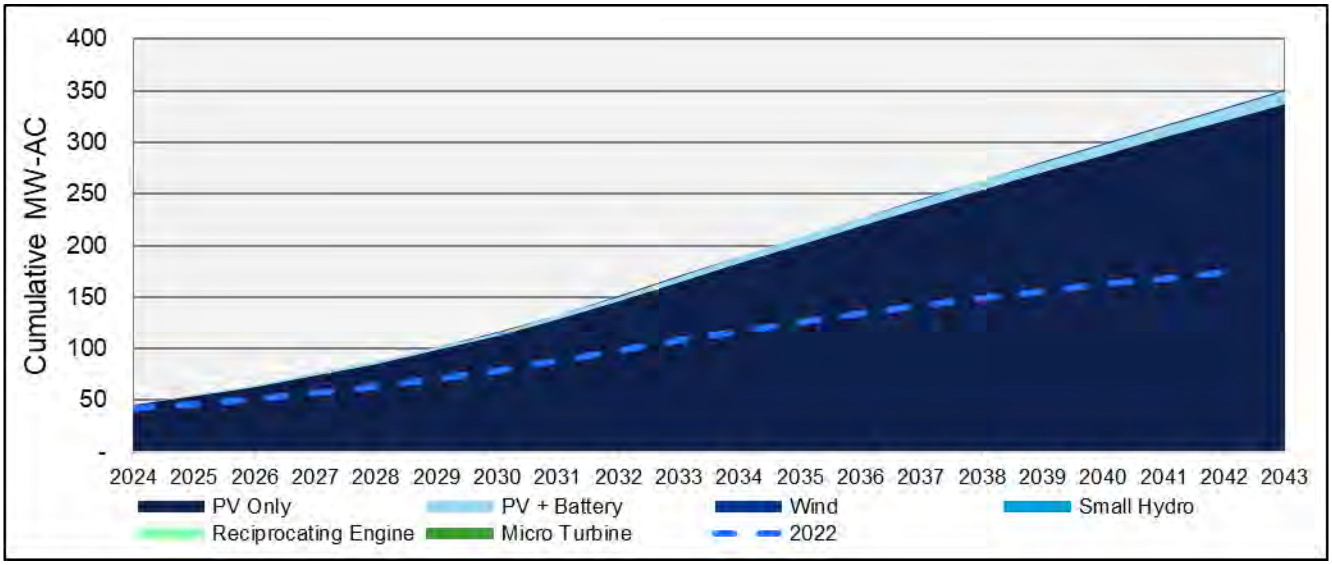


**Figure 4-32. Cumulative new capacity installations by technology (MW-AC), Washington high case, 2024-2043**

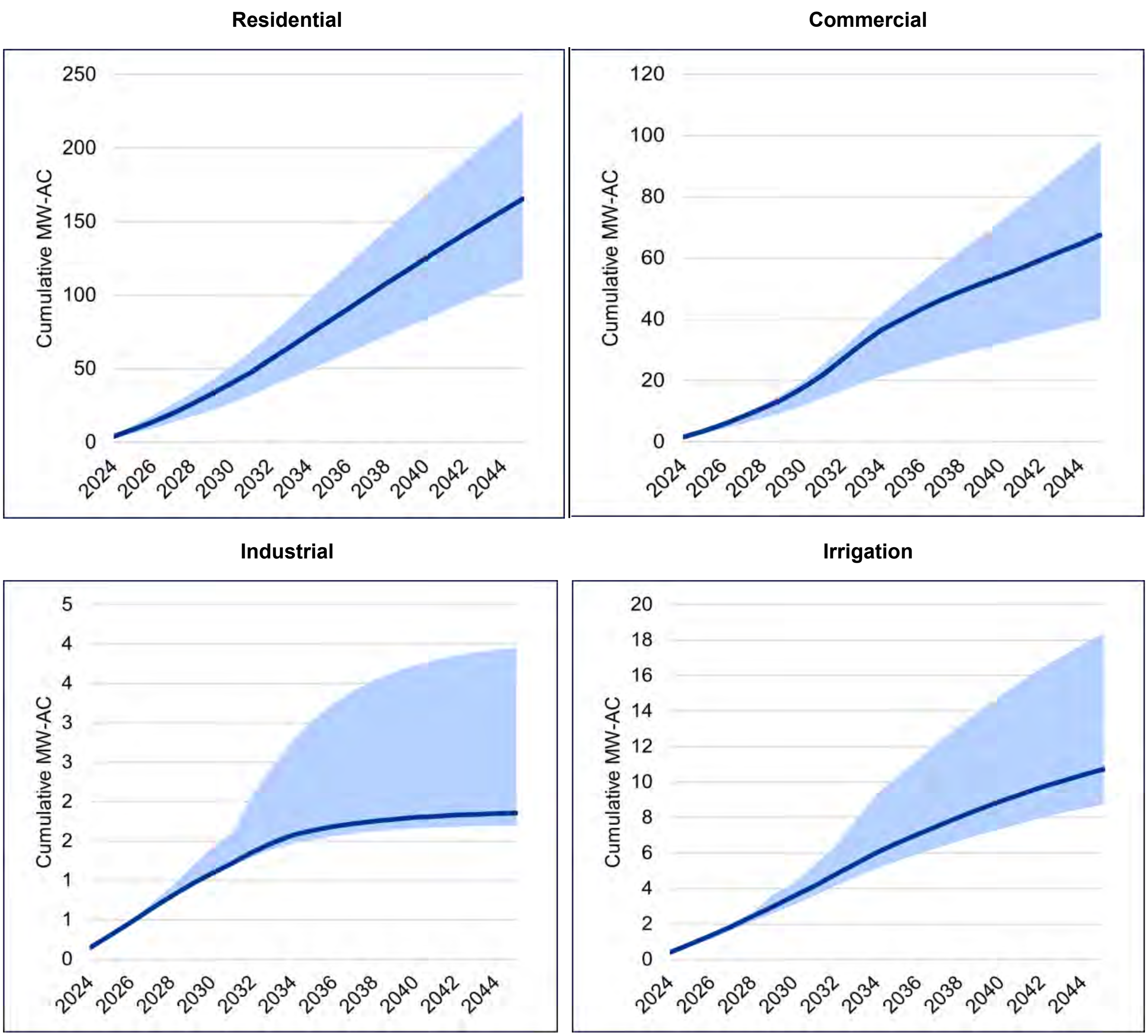


### 4.1.5.1 Washington PV adoption by sector

The differences in PV capacity relative to the base case for the three modeled scenarios across the four sectors are presented in the following charts. In the residential sector, the share of PV + Battery capacity is about 4% of total residential PV capacity in 2042. The share of PV + Battery capacity is about 3% of total commercial PV capacity in 2042. The industrial sector has a higher portion of its PV capacity in PV + Battery configurations, at 8% of total capacity. In the irrigation sector, the share of PV + Battery capacity is between 2% and 4%, depending on the forecast scenario, of total irrigation PV capacity in 2042.

**Figure 4-33. Cumulative new PV capacity installed by sector across all scenarios, Washington, 2024-2043**

*Upper and lower bounds (in blue) represent the high and low case forecasts, with a line for the base case.*



## 4.1.6 Wyoming

PacifiCorp's customers in Wyoming are projected to install about 75 MW of new distributed generation capacity or ~10,450 new customers over the next two decades in the base case. The 20-year high projection is approximately 37% greater than the base case and the low projection is 48% less than the base case, or 132 MW and 43 MW, respectively.

Wyoming currently offers no incentives for distributed generation technologies. The residential sector has the largest share of the distributed generation capacity, ranging from 71% in the low case to 78% in the high case, and 79% in the base case. The next largest share of the capacity is forecasted in the commercial sector, ranging from 21% in the high and base cases to 28% in the low case. Wyoming's net metering policies were assumed to stay in place throughout the study, providing more favorable economics for PV Only compared to PV + Battery systems.

**Figure 4-34. Cumulative new distributed generation capacity installed by scenario (MW-AC), Wyoming, 2018-2043**

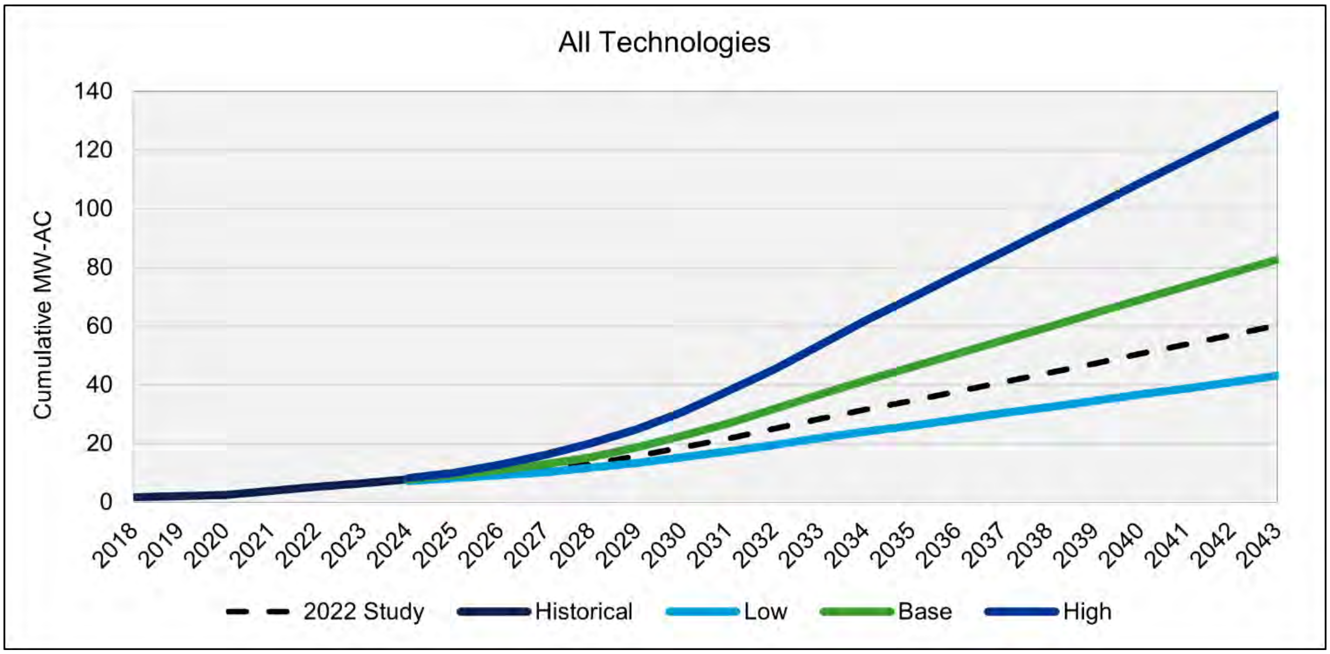


**Figure 4-35. Cumulative new capacity installations by technology (MW-AC), Wyoming base case, 2024-2043**

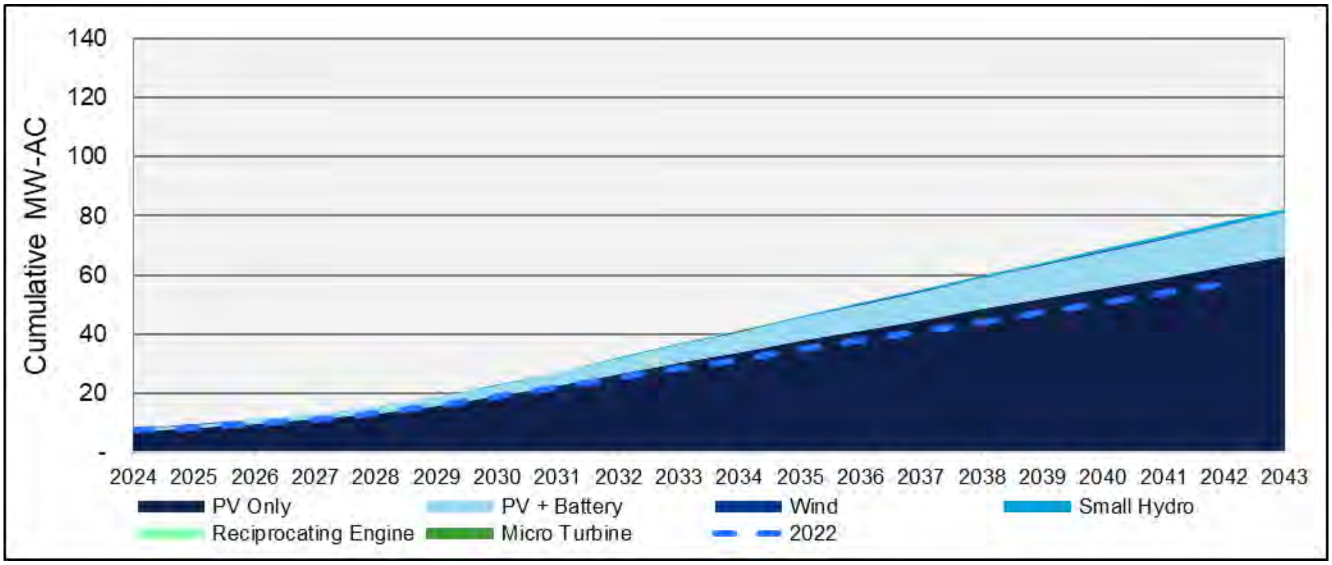



**Figure 4-36. Cumulative new capacity installations by technology (MW-AC), Wyoming low case, 2024-2043**

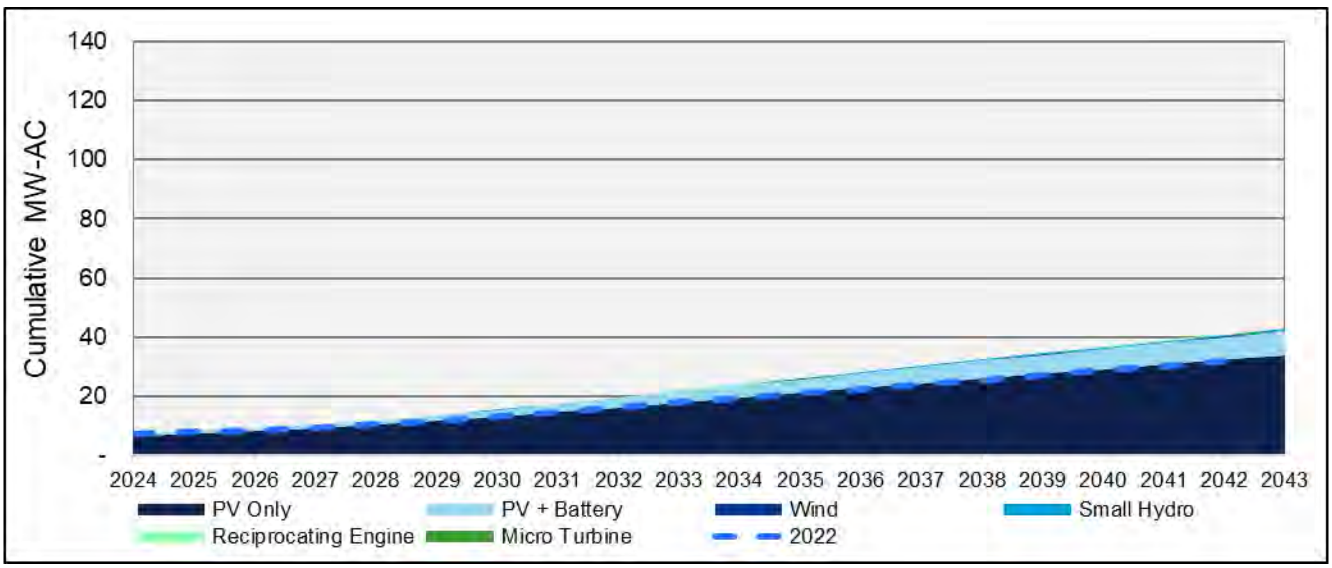
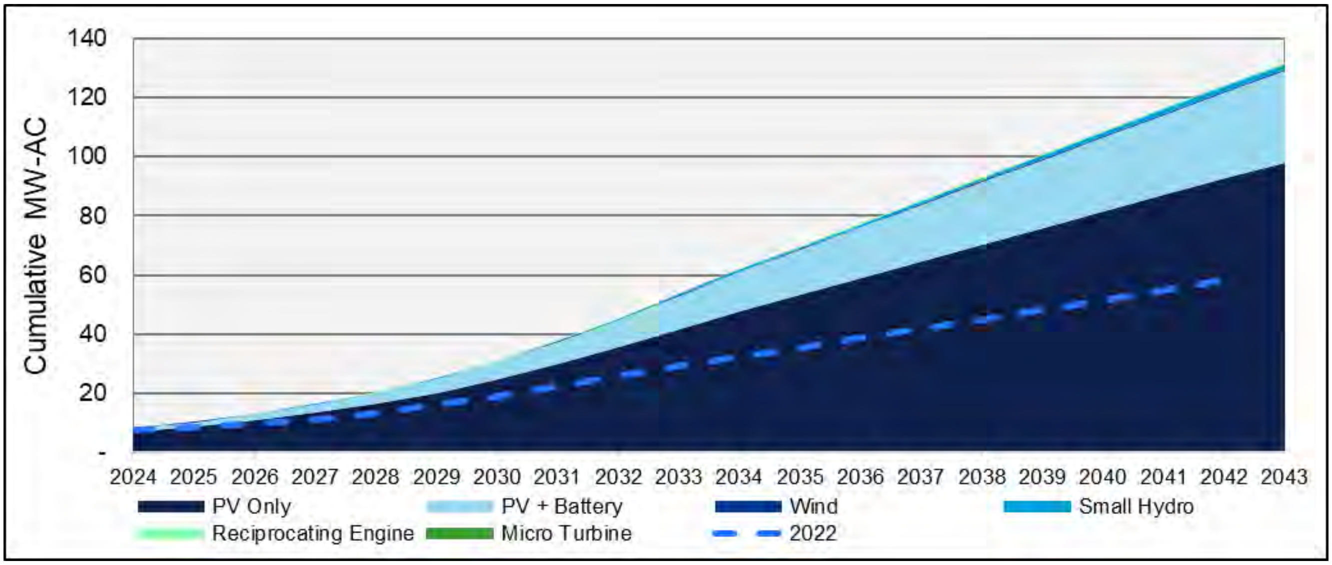


**Figure 4-37. Cumulative new capacity installations by technology (MW-AC), Wyoming high case, 2024-2043**

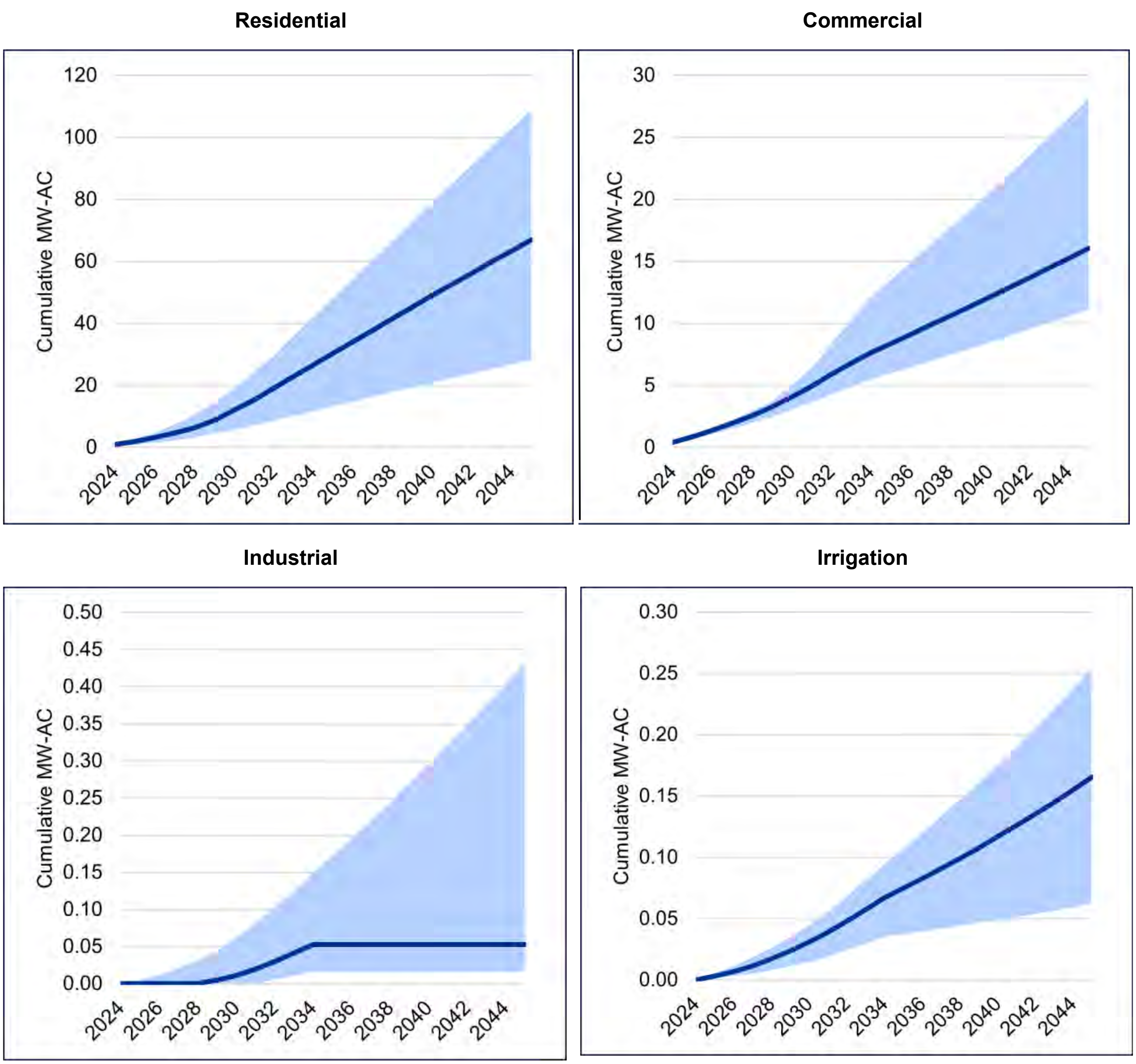


#### 4.1.6.1 Wyoming PV adoption by sector

The differences in PV capacity relative to the base case for the three modeled scenarios across the four sectors are presented in the following charts. In the residential sector, the share of PV + Battery capacity is between 19% and 23% of total residential PV capacity in 2042, depending on the forecast scenario. The share of PV + Battery capacity is about 6% of total commercial PV capacity in 2042. The industrial sector has a lower portion of its PV capacity in PV + Battery configurations, at 5% of total capacity. The irrigation sector did not have any PV (PV Only or PV + Battery) adoption forecasted.

**Figure 4-38. Cumulative New PV capacity installed by sector across all scenarios, Wyoming, 2024-2043**

*Upper and lower bounds (in blue) represent the high and low case forecasts, with a line for the base case.*



# 5 APPENDIX

## 5.1 Technology assumptions and segment-level inputs

Appendix A.xlsx

## 5.2 Detailed results

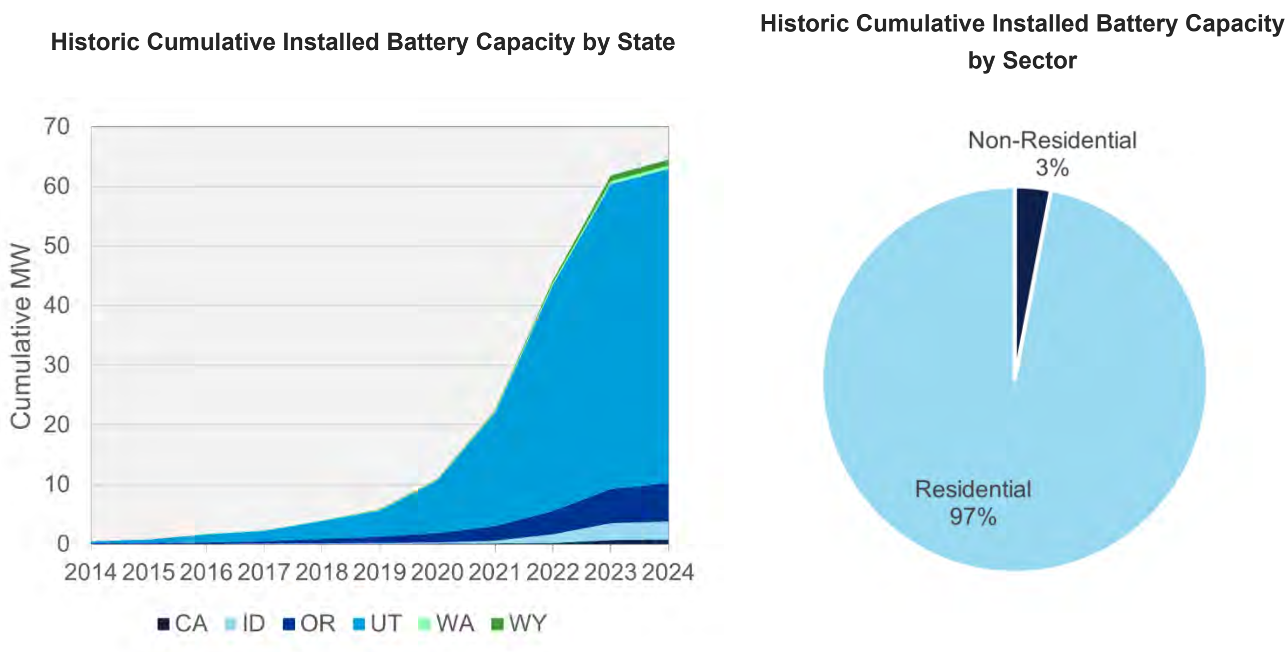
Appendix B.xlsx

## 5.3 Behind-the-meter battery storage forecast

DNV prepared a behind-the-meter battery storage forecast as a part of the Long-Term Distributed Generation Resource Assessment for PacifiCorp covering their service territories in Utah, Oregon, Idaho, Wyoming, California, and Washington to support PacifiCorp's 2024 Integrated Resource Plan (IRP). This study evaluated the expected adoption of behind-the-meter battery storage systems coupled with PV systems over a 20-year forecast horizon (2024-2043) for all customer sectors (residential, commercial, industrial, and agricultural). Residential and non-residential battery energy storage systems (BESS) can be installed as a standalone system, added to an existing PV system, or the system can be installed together with a new PV system. DNV assumed all battery installations would be paired with a PV system in an AC-coupled configuration, as standalone systems are ineligible for the federal ITC—explained further in section 3.1.6.

The adoption model DNV developed for this study is calibrated to the current[16] installed and interconnected behind-the-meter battery capacity that is paired with a PV system, shown in Figure 5-1.

**Figure 5-1. Historic cumulative installed behind-the-meter battery storage capacity, PacifiCorp, 2014-2024**




### 5.3.1 Study methodologies and approaches

DNV modelled two technologies in the behind-the-meter battery storage forecast:

1. **PV + Battery**: BESS product installed together with a new PV system,
2. **Battery Retrofit**: BESS product installed as an add-on to an existing PV system.

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[16] PacifiCorp distributed generation interconnection data as of April 2024.

DNV used the same forecasting methodologies and approaches for the BTM battery storage forecast as the distributed generation forecast. The methods used to develop the results of the forecast are described in detail in section 3.3 of the report.

Data on battery system costs used in the BTM battery storage forecast is explained in detail in section 3.1.1.2 of the report. That section includes current and projected future costs of battery storage systems used in the forecast for the different sectors. The detailed assumptions for the system configurations, including system sizes, in each sector and state can be found in Appendix A, section 5.1.

### 5.3.2 Battery dispatch modelling

DNV utilized its proprietary solar plus storage operational modeling tool—Lightsaber—to model battery dispatch. Battery dispatch strategy dictates the flow of energy between the PV system, battery, and the grid. The battery dispatch model includes strategies such as peak shaving, energy arbitrage, and manual dispatch. Self-consumption was modeled for all sectors' BESS control strategy, which utilizes the battery by charging only from excess PV and discharging if PV production falls below load. For residential customers, the dispatch model used energy arbitrage to reduce time-of-use charges.[17] For non-residential customers, the dispatch model used energy arbitrage to reduce demand charges and time-of-use charges, where applicable.

### 5.3.3 Results

In the base case scenario, DNV estimates 407 MW of new BTM battery storage capacity will be installed in PacifiCorp's service territory over the next twenty years (2024-2043) (Table 5-1). Figure 5-2 shows the relationship between the base case and low and high case scenario forecasts, with the cumulative totals a summation of the existing ~62 MW of installed battery capacity and the forecasted 20-year adoption. The low-case scenario estimates 337 MW of new capacity over the 20-year forecast period—compared to the base case, retail rates increase at a slower rate, and technology costs decrease at a slower rate. In the high case, retail rates increase at a faster rate, and technology costs decrease at a faster rate. The twenty-year total new capacity forecasted in the high case is about 34% greater than the base case, while the low case is 24% less.

**Table 5-1. Cumulative adopted battery storage capacity by 2043, by scenario**

| Scenario | Cumulative capacity (2043 mw) |
|---|---:|
| **High** | 530 |
| **Base** | 407 |
| **Low** | 337 |

[17] Modeling parameters include PacifiCorp's actual on- and off-peak ratios, which are relatively low when compared to other jurisdictions.

**Figure 5-2. Cumulative new battery storage capacity installed by scenario (MW), 2023-2042**

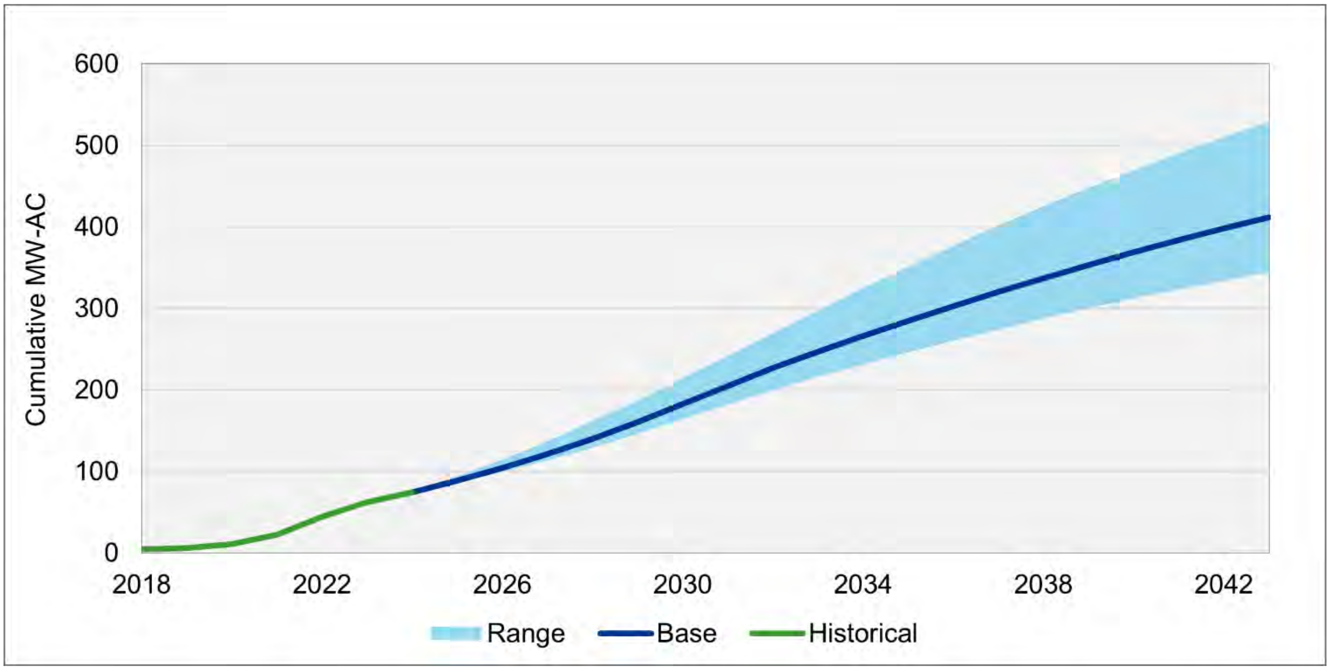



Figure 5-2 shows how the forecasts by customer sector and technology for each scenario. In all scenarios of the forecast, the residential sector represents about 90% of the new battery storage capacity forecasted to be installed over the next twenty years. The commercial, industrial, and irrigation sectors have been bundled into a single “Non-Residential” sector to present the results in the report, as the capacity forecasts in the individual sectors are very small relative to the total forecast. PV + Battery systems represent the greatest share of the new battery capacity forecasted in the base and high cases. Battery Retrofit systems representing a greater share of the new battery capacity forecasted in the low case indicate that customers are more likely to adopt a PV Only system over a PV + Battery system when technology costs are higher, and electricity rates are lower.

### 5.3.4 Storage capacity results by state

As was the case in the distributed generation forecast, Utah represents the largest share of the battery capacity forecast. To date, the majority of installed battery storage capacity and annual growth in storage capacity has been in Utah, which represents the largest portion go PacifiCorp’s customer population. Battery adoption is expected to continue to grow in Utah, with the state’s share of total new capacity reaching between 81% and 84%, depending on the scenario, over the next twenty years. The net billing structure in place in Utah incentivizes PV + Battery storage co-adoption more so than traditional net metering, as customers can lower their electricity bills by charging their batteries with excess PV generation and dispatching their batteries to meet on-site load during times of day when retail energy prices are high. Oregon represents the second largest portion of the new capacity forecasted, between 8% and 10%. Net metering is the DER compensation mechanism in place in Oregon, but customer economics are boosted by PV + Battery incentives provided through the Oregon Department of Energy.[18]

[18] Oregon.Gov. “Oregon Solar + Storage Rebate Program.”.https://www.oregon.gov/energy/Incentives/Pages/Solar-Storage-Rebate-Program.aspx

**Figure 5-3. Cumulative new battery storage capacity installed by state (MW), 2024-2043, base case**

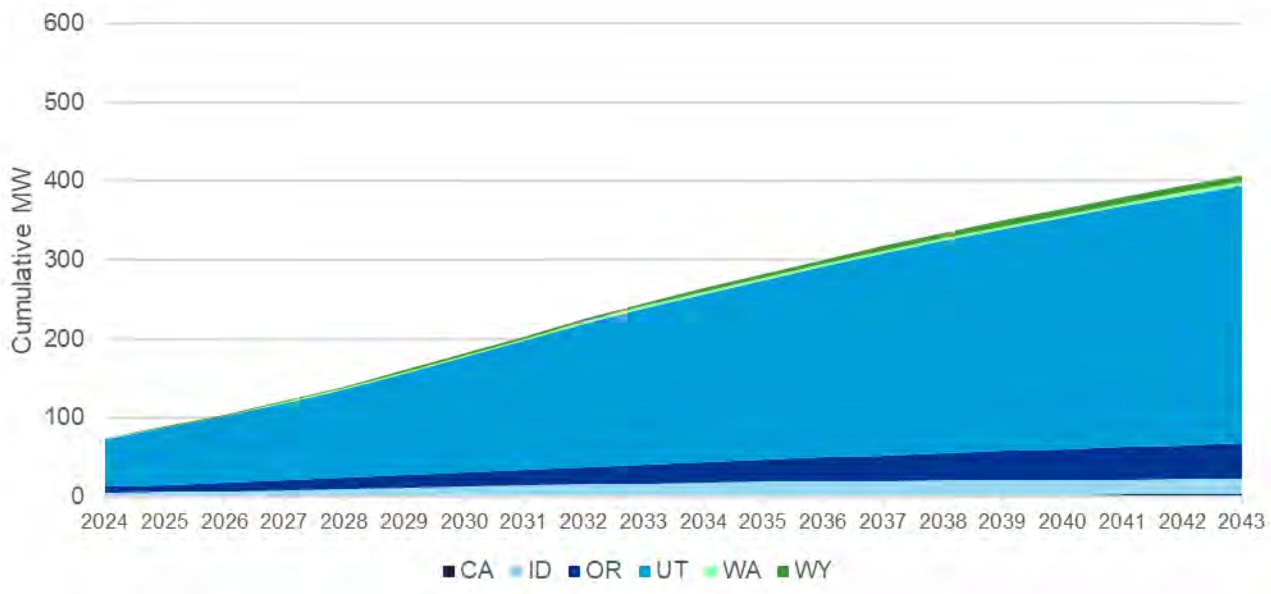



**Figure 5-4. Cumulative new battery storage capacity installed by state (MW), 2024-2043, low case**

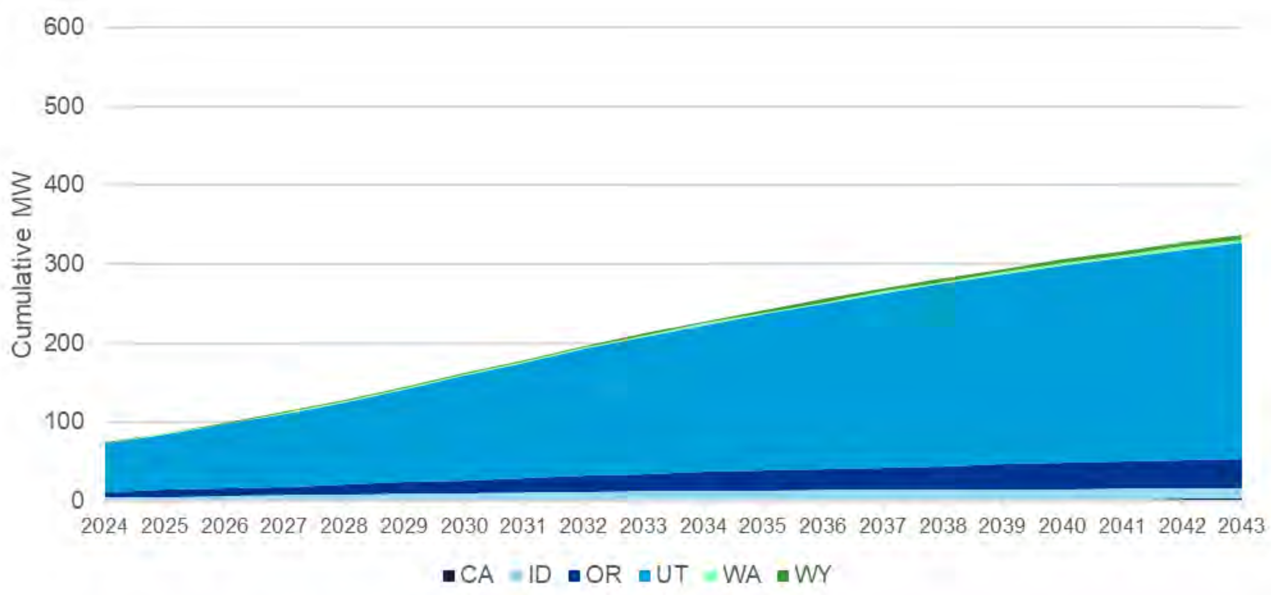
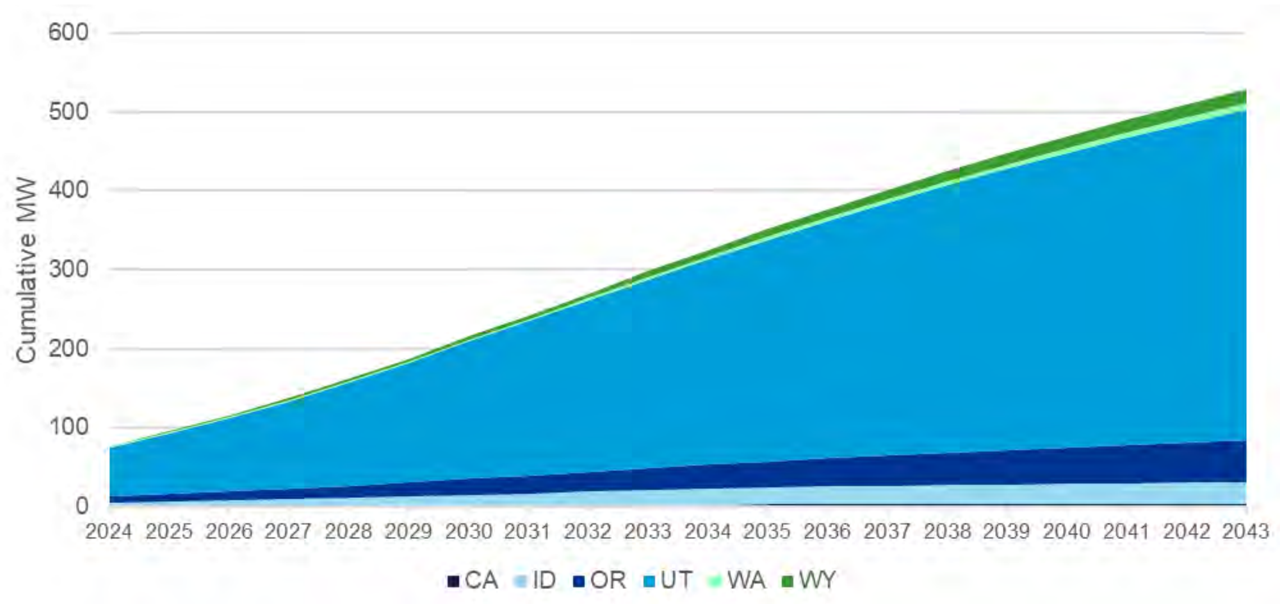


Figure 5-5. Cumulative new battery storage capacity installed by state (MW), 2024-2043, high case




The following figures show the state-level forecasts in more detail. Background and commentary on the individual states' results can be found in section 4.1 of the report.

## California

**Figure 5-6. Cumulative new battery storage capacity installed by scenario (MW), California, 2028-2043**

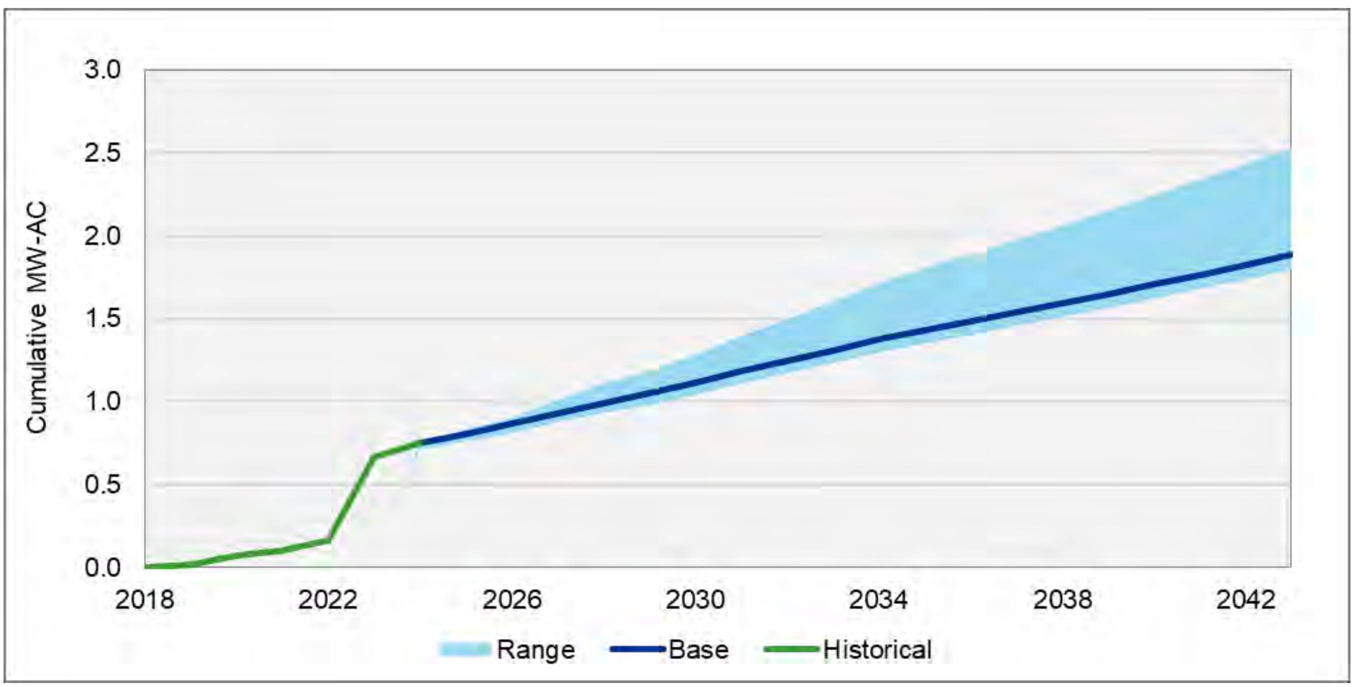
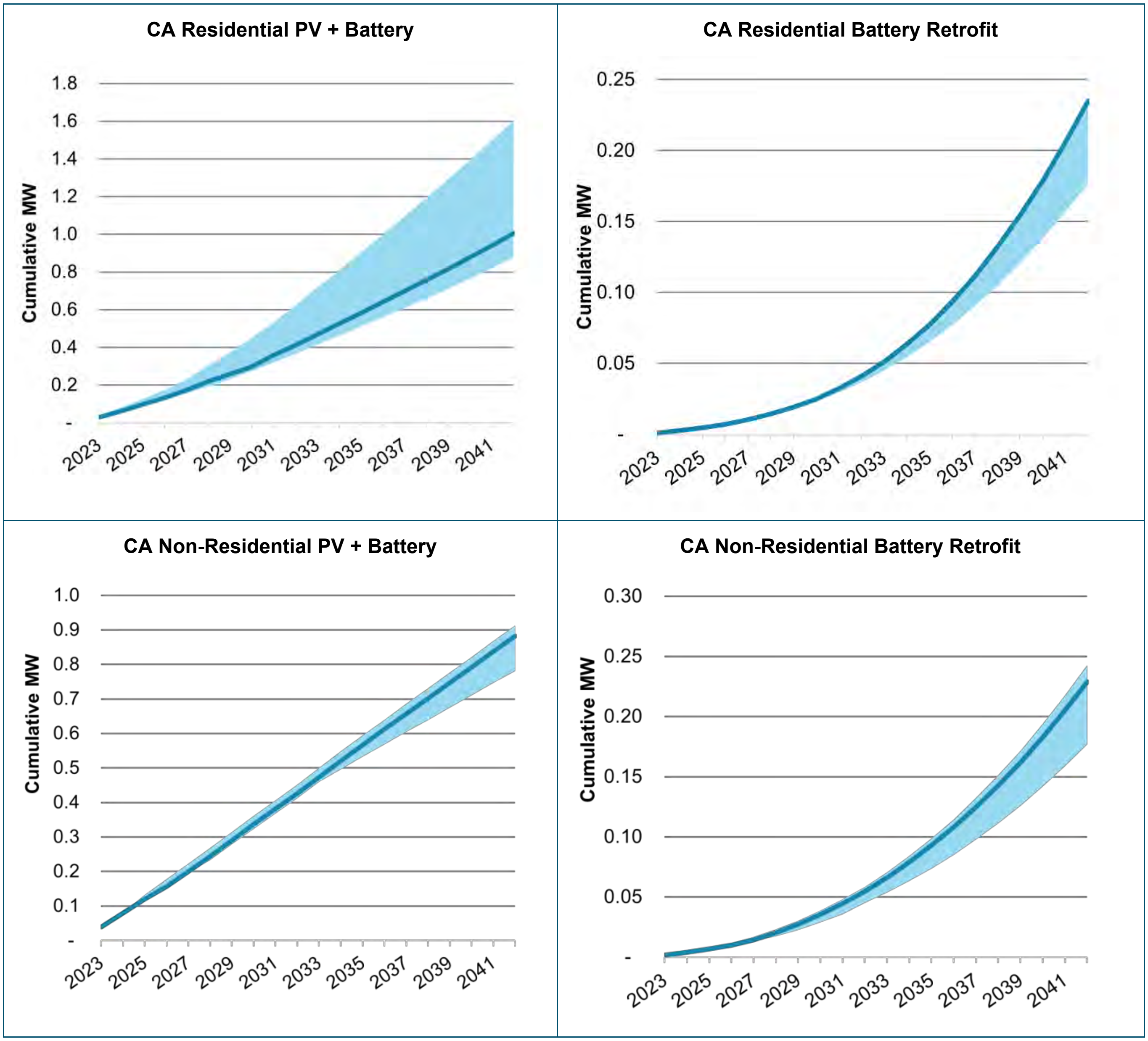


**Figure 5-7. Cumulative new battery storage capacity installed by technology across all scenarios (MW), California, 2023-2042**

Upper and lower bounds (in blue) represent the high and low case forecasts, with a line for the base case.



## Idaho

**Figure 5-8. Cumulative new battery storage capacity installed by scenario (MW), Idaho, 2018-2043**

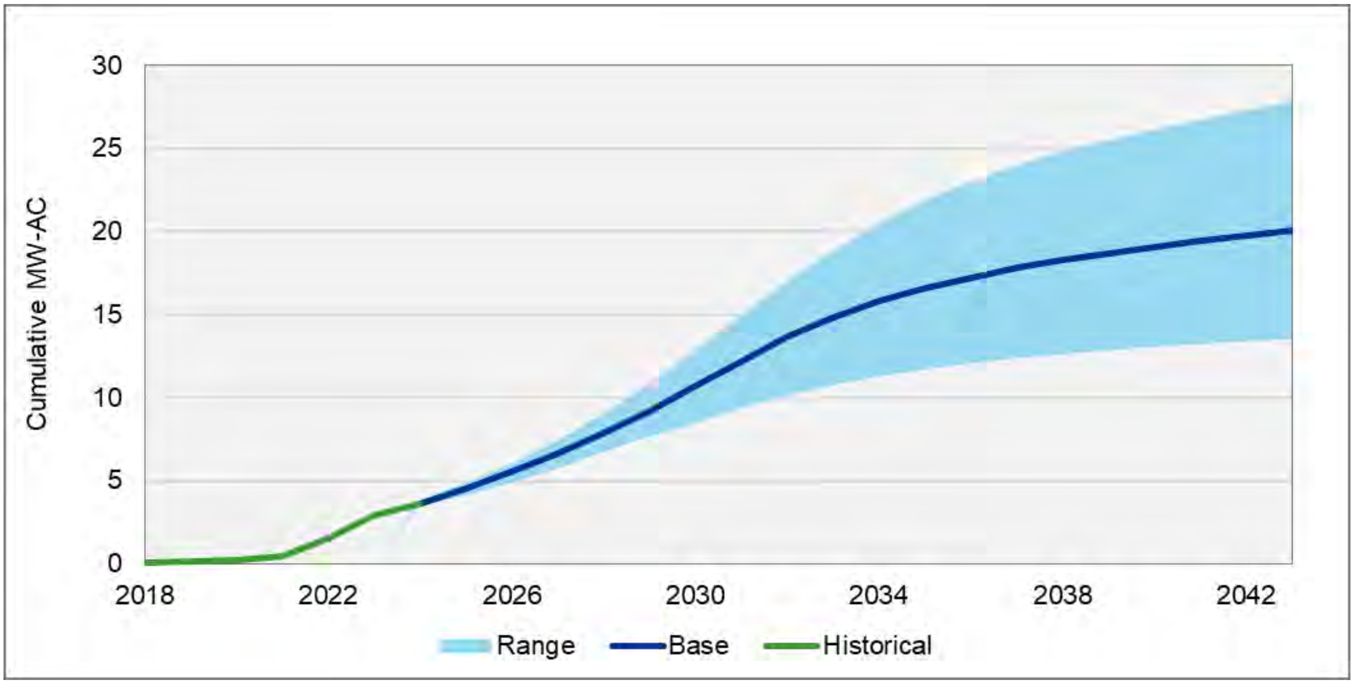
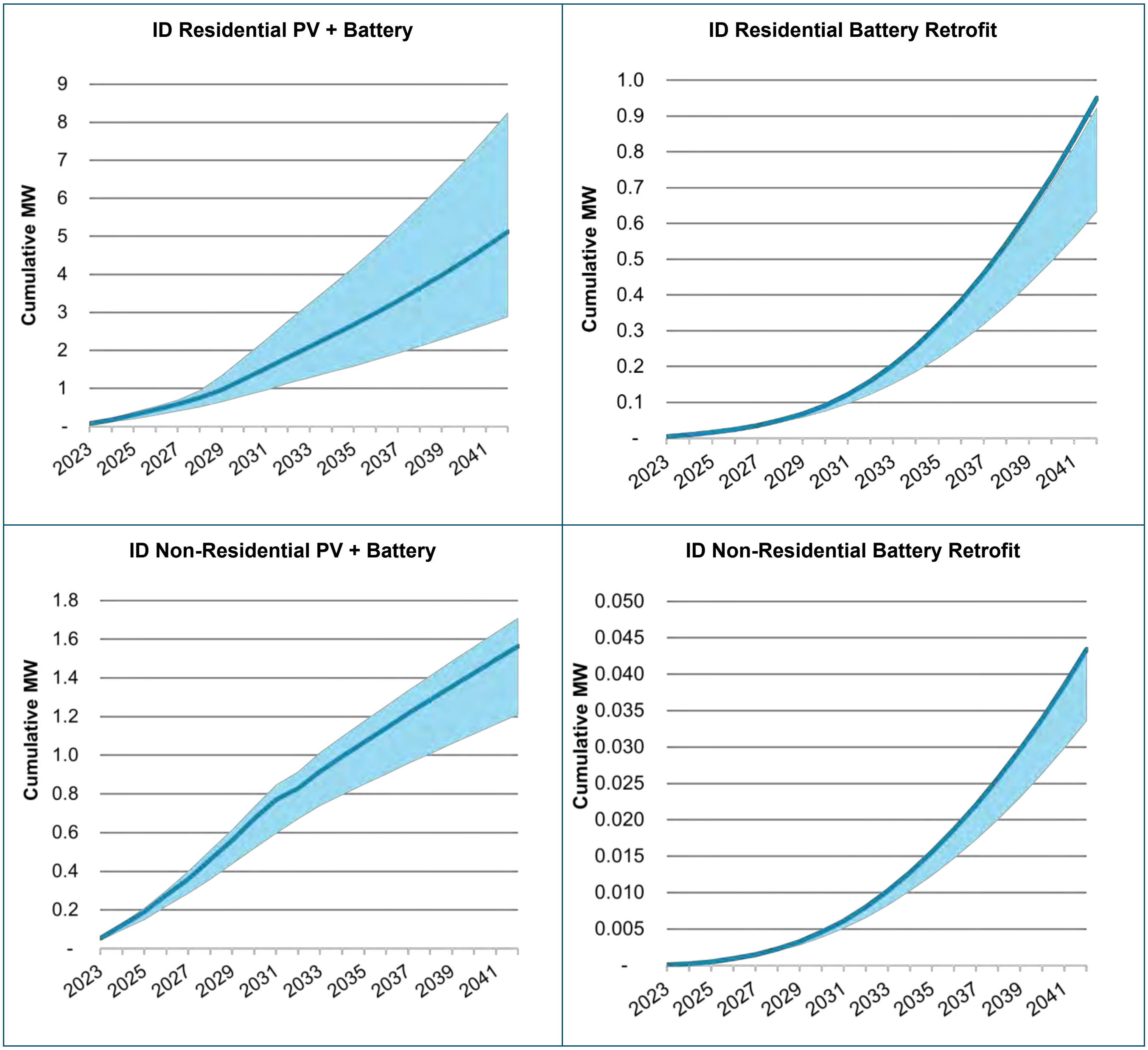


**Figure 5-9. Cumulative new battery storage capacity installed by technology across all scenarios (MW), Idaho, 2023-2042**

Upper and lower bounds (in blue) represent the high and low case forecasts, with a line for the base case.



## Oregon

**Figure 5-10. Cumulative new battery storage capacity installed by scenario (MW), Oregon, 2018-2043**

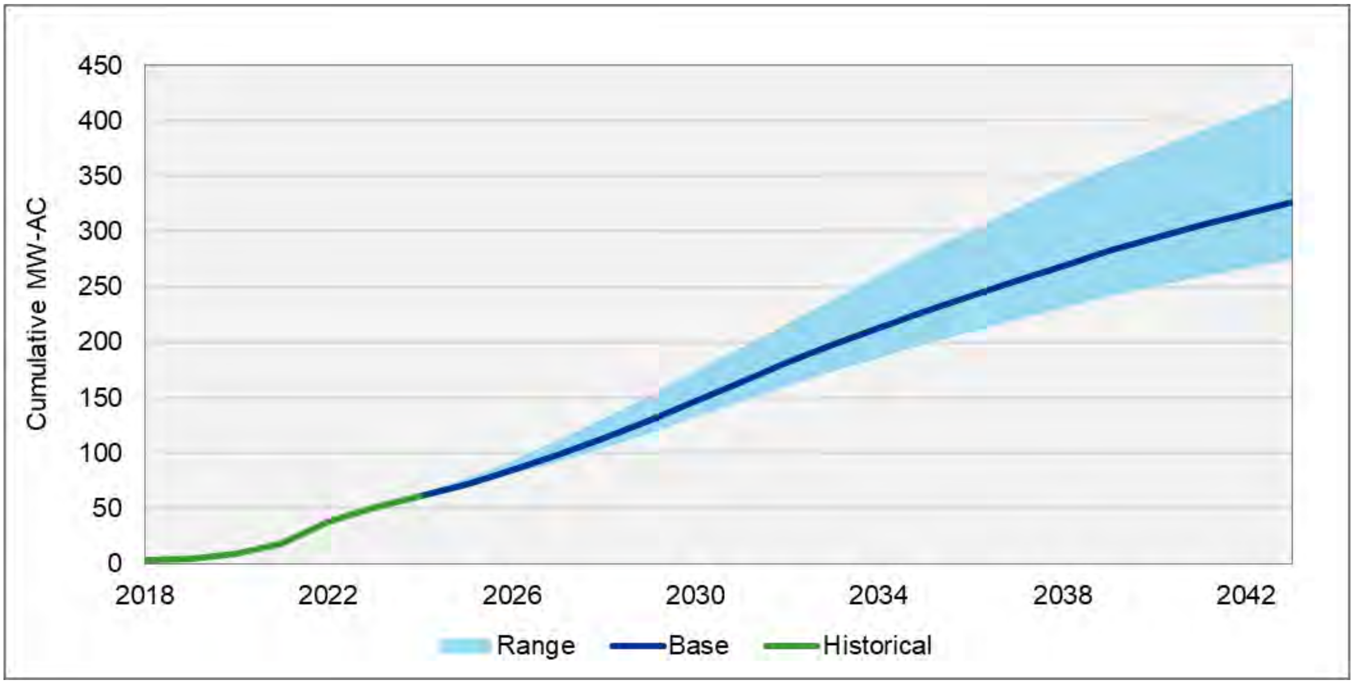
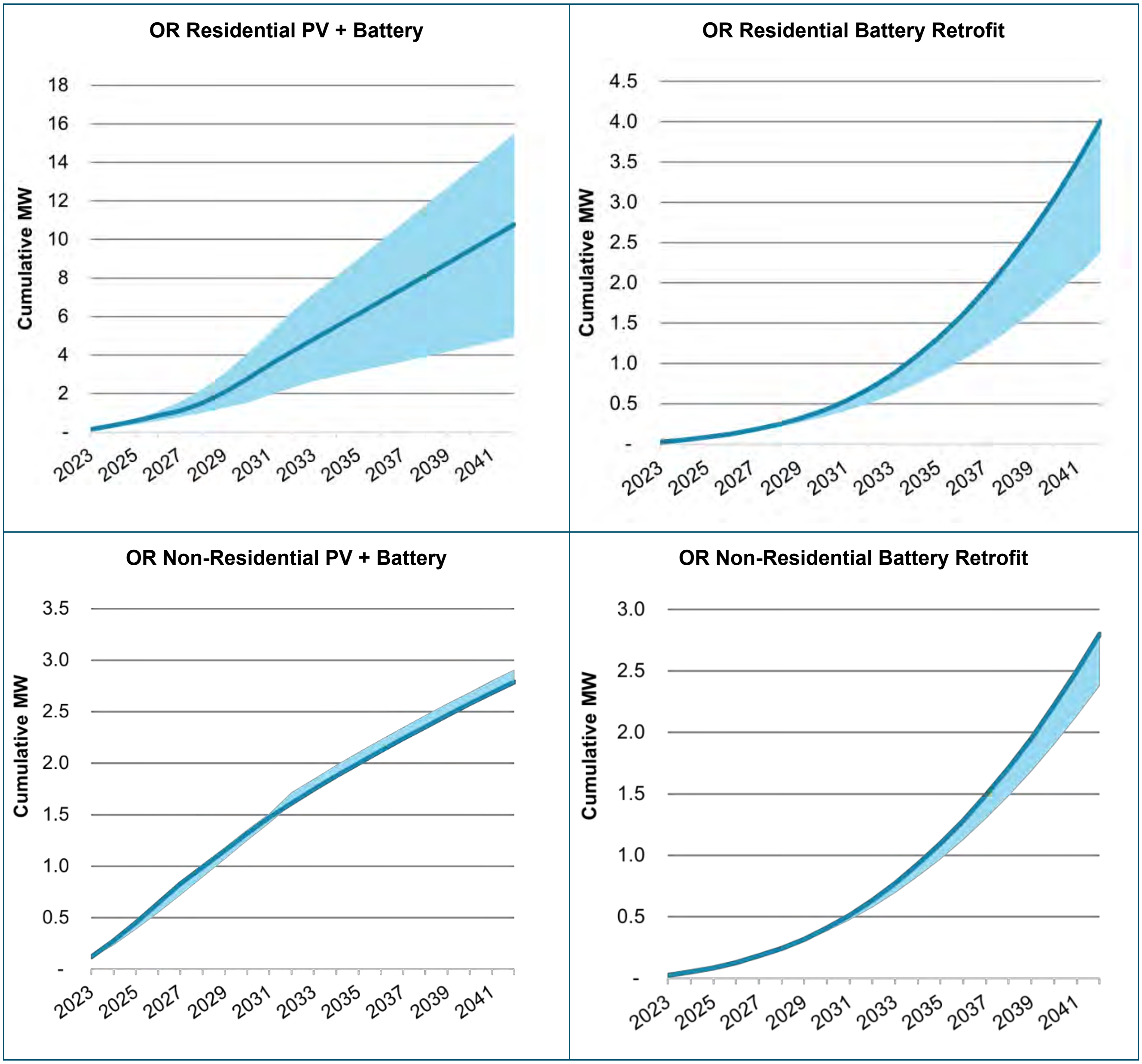


**Figure 5-11. Cumulative new battery storage capacity installed by technology across all scenarios (MW), Oregon, 2023-2042**

Upper and lower bounds (in blue) represent the high and low case forecasts, with a line for the base case.



## *Utah*

**Figure 5-12. Cumulative new battery storage capacity installed by scenario (MW), Utah, 2018-2043**

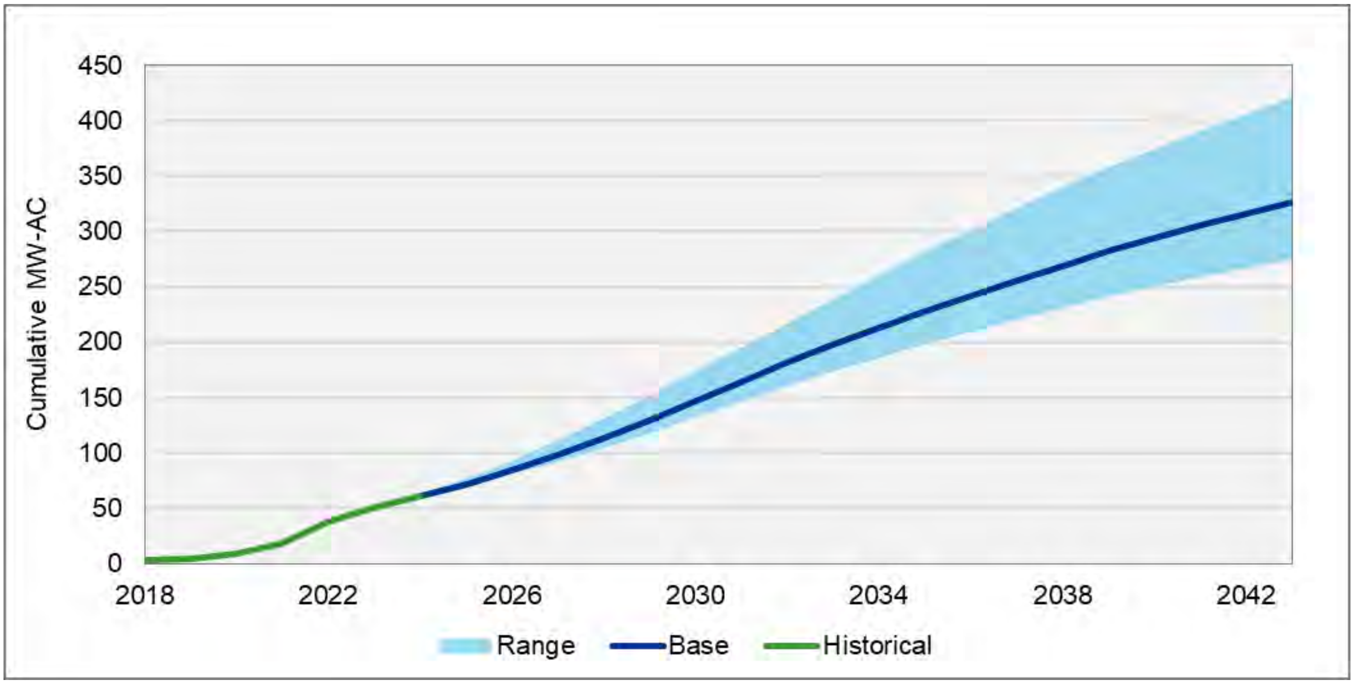
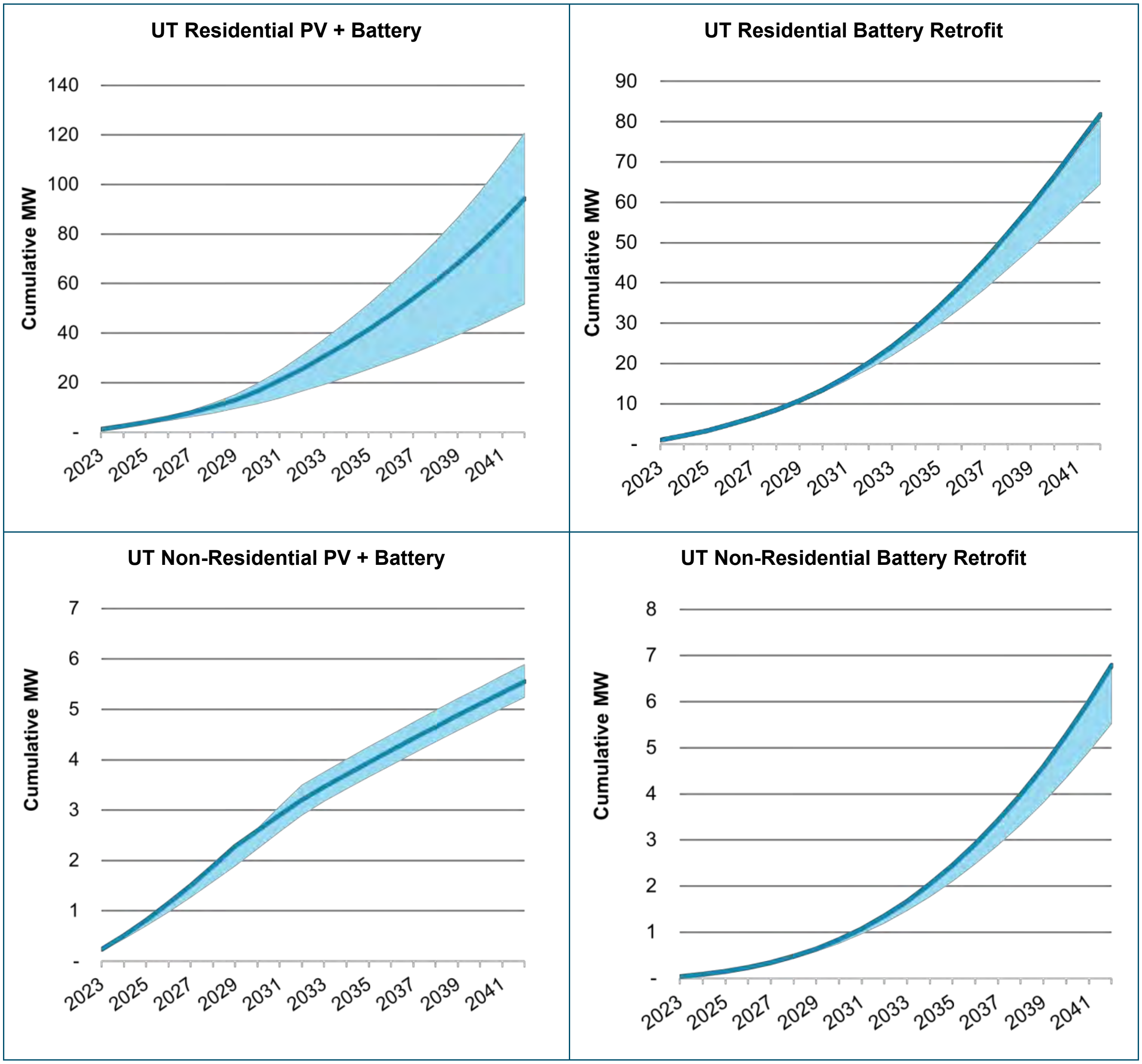


**Figure 5-13. Cumulative new battery storage capacity installed by technology across all scenarios (MW), Utah, 2023-2042**

Upper and lower bounds (in blue) represent the high and low case forecasts, with a line for the base case.



### *Washington*

**Figure 5-14. Cumulative new battery storage capacity installed by scenario (MW), Washington, 2018-2043**

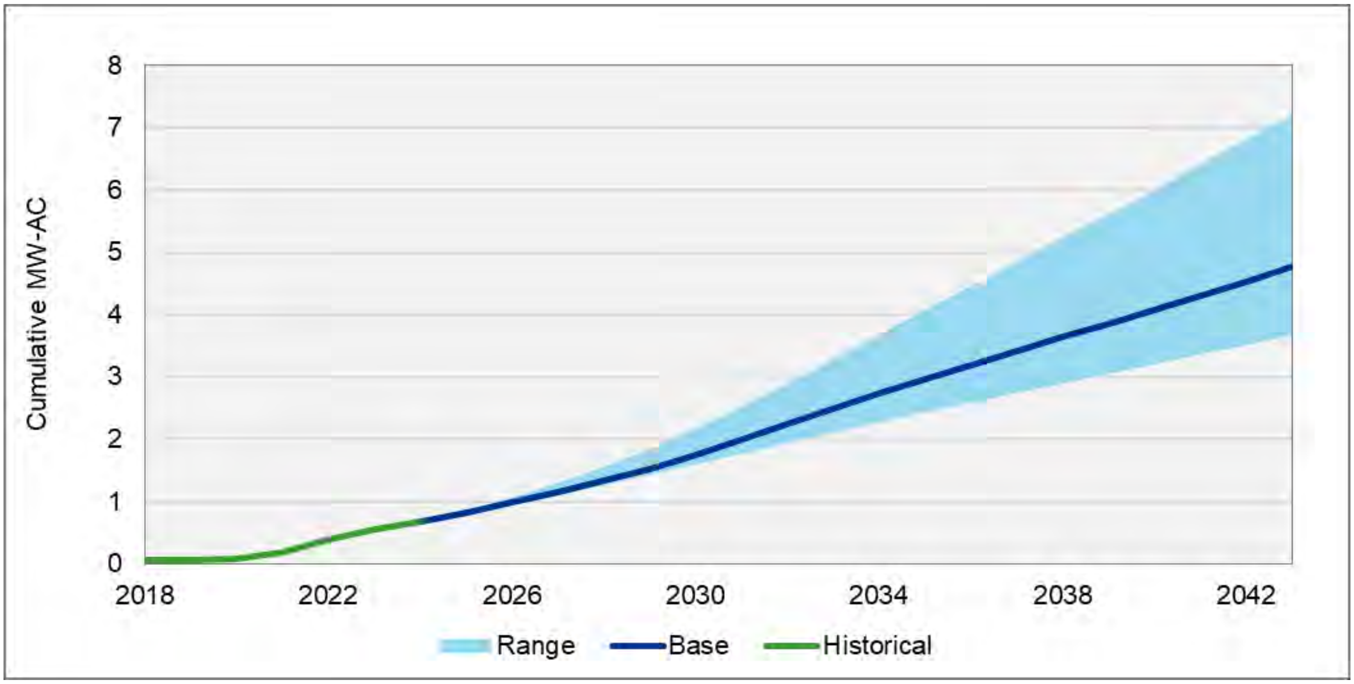
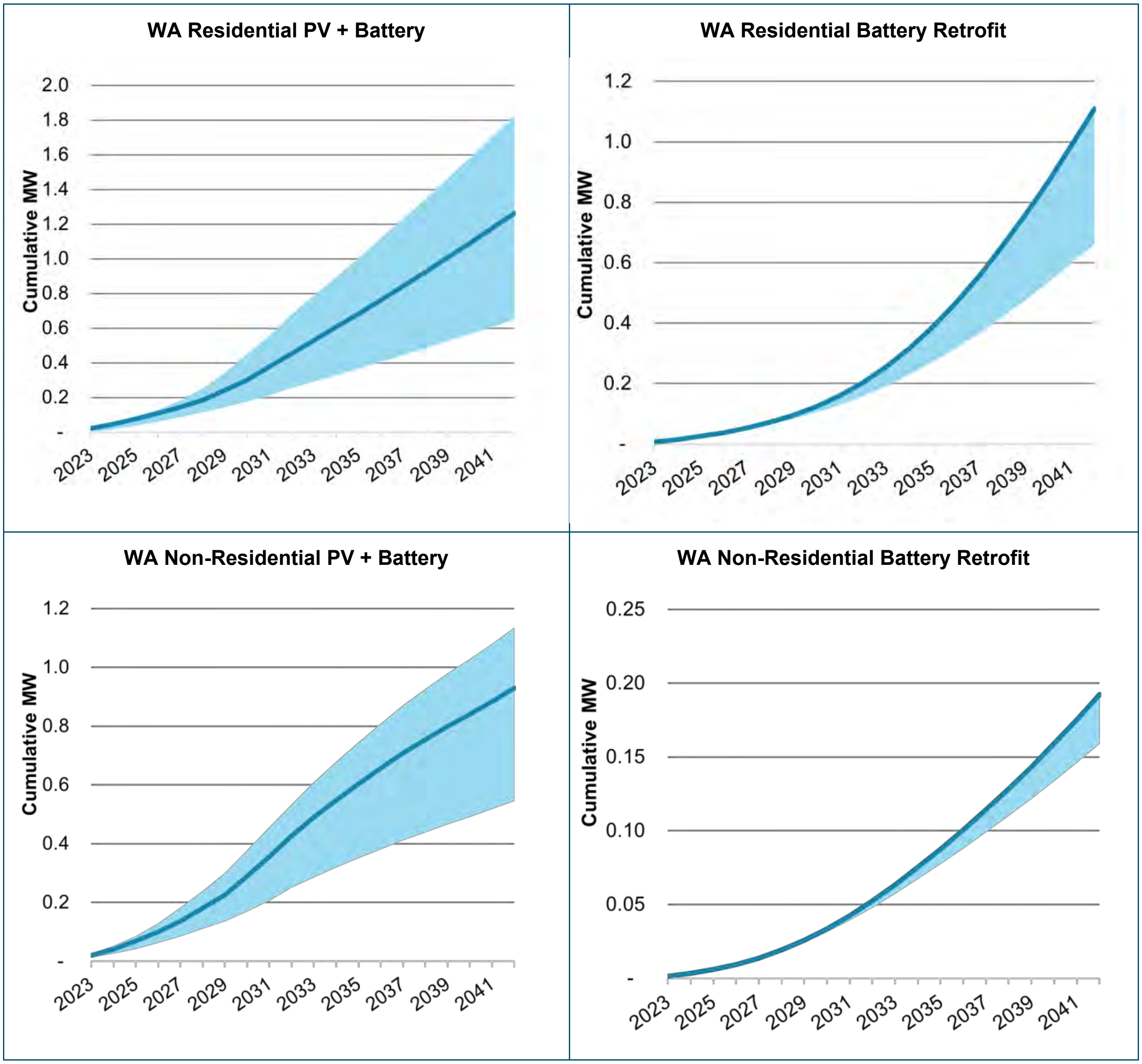


**Figure 5-15. Cumulative new battery storage capacity installed by technology across all scenarios (MW), Washington, 2023-2042**

Upper and lower bounds (in blue) represent the high and low case forecasts, with a line for the base case.



## *Wyoming*

**Figure 5-16. Cumulative new battery storage capacity installed by scenario (MW), Wyoming, 2018-2043**

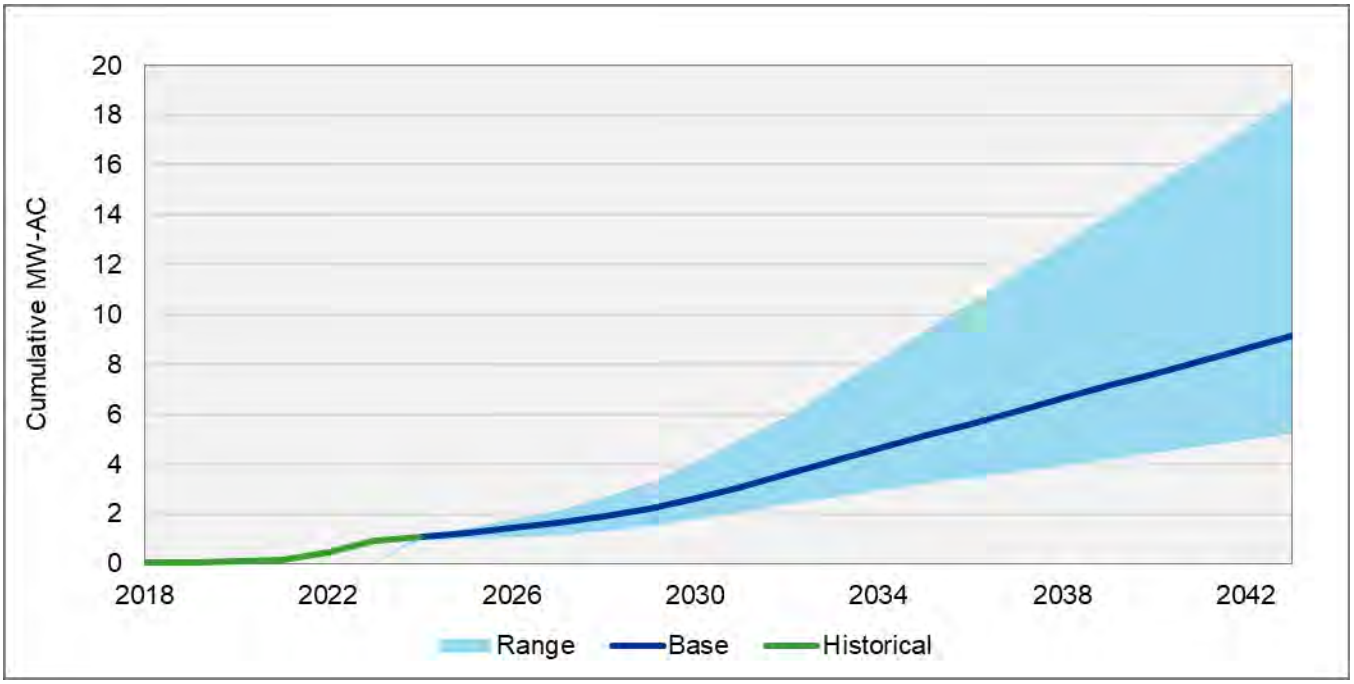
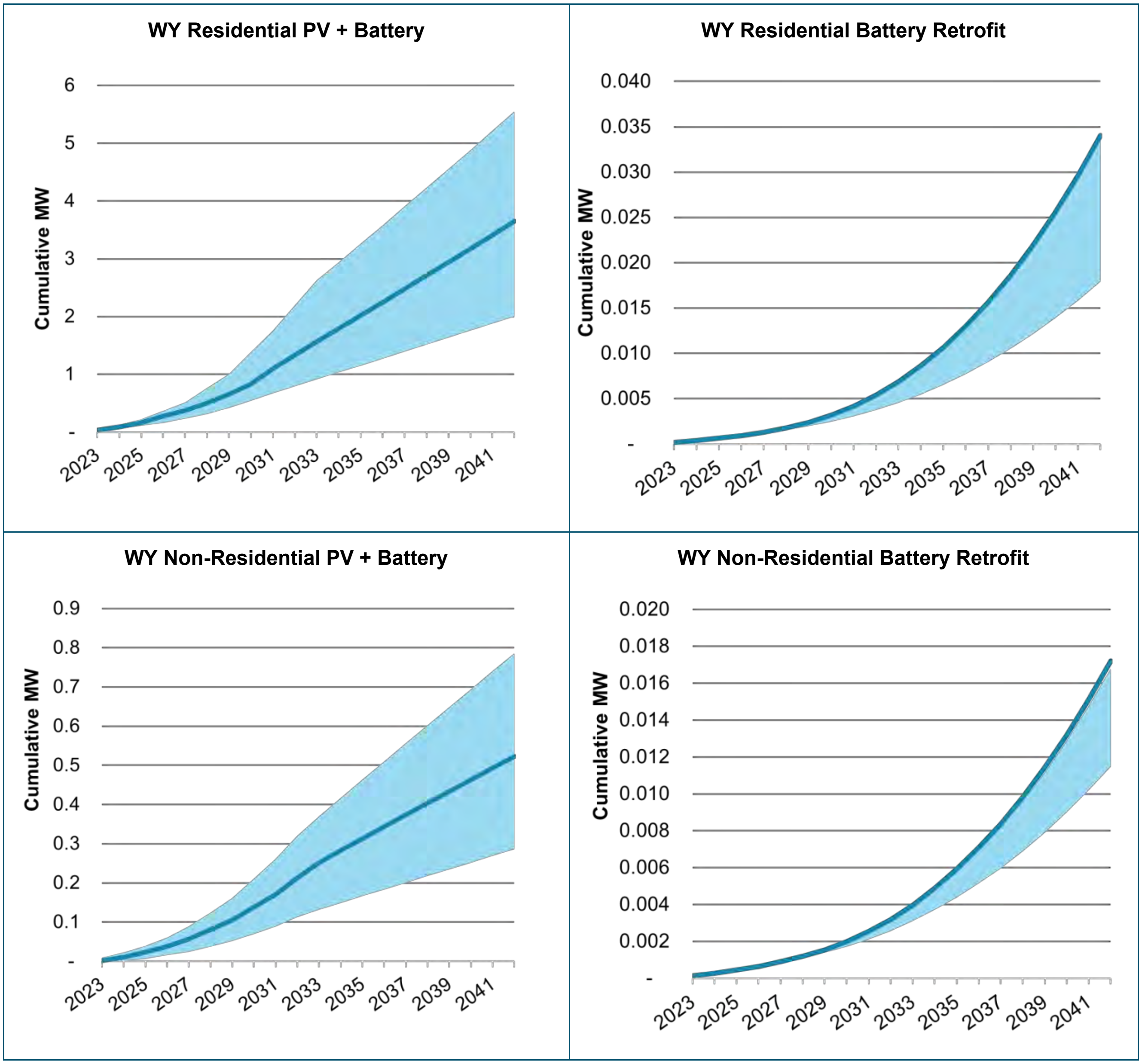


**Figure 5-17. Cumulative new battery storage capacity installed by technology across all scenarios (MW), Wyoming, 2023-2042**

Upper and lower bounds (in blue) represent the high and low case forecasts, with a line for the base case.



## About DNV

DNV is a global quality assurance and risk management company. Driven by our purpose of safeguarding life, property and the environment, we enable our customers to advance the safety and sustainability of their business. We provide classification, technical assurance, software and independent expert advisory services to the maritime, oil & gas, power and renewables industries. We also provide certification, supply chain and data management services to customers across a wide range of industries. Operating in more than 100 countries, our experts are dedicated to helping customers make the world safer, smarter and greener.

# APPENDIX M – STAKEHOLDER FEEDBACK FORMS

## Introduction

As of December 2024, stakeholder have submitted 71 stakeholder feedback forms, summarized below. Stakeholder feedback forms, including PacifiCorp responses, are publicly posted to the IRP website. The stakeholder feedback forms have allowed the company to review and summarize issues by topic as well as identify and respond to specific recommendations. Information collected was used to inform the 2025 IRP development process, including feedback related to process improvements and input assumptions, as well as responding directly to stakeholder questions.

Footnote references to stakeholder feedback are also included in the chapters and appendices of the 2025 IRP where relevant.

## Stakeholder Feedback Form Summary

The table below summarizes the publicly available forms and PacifiCorp responses.

**Table C.1 – Stakeholder Feedback Form Summary**

| SFF # | Request Topic | PacifiCorp Reply | Reference |
|---|---|---|---|
| 2025.001 Peter Gross (1/11/24) | Nuclear power | PacifiCorp is managing risks to ensure that any nuclear resource must bring value to customers. | Chapter 7 |
| 2025.003 OPUC (5/7/24) | Modeling inputs and scenarios | Anticipated inputs and assumptions listed in slide 34 of 1/25/24 PIM; inputs discussed throughout the PIM series. | Appendix C |
| 2025.004 PRBRC (5/6/24) | TerraPower agreement | Natrium demonstration project will be updated in 2025 IRP. | Chapter 10 |
| 2025.005 PRBRC (5/6/24) | Bridger Units 3 & 4 2023 IRP update errata request | Assumptions will be refreshed in 2025 IRP. | Chapter 8 |
| 2025.006 Renewable NW (5/3/24) | Distributed generation study | DNV/PacifiCorp working to improve modeling approach on an ongoing basis. | Chapter 6 |
| 2025.007 Renewable NW (5/3/24) | Renewable resource cost estimates | PacifiCorp will seek feedback on cost structure/forecasting as part of the 2025 public input process; modeling best available information. | Chapter 7 |
| 2025.008 WRA (5/6/24) | IRP Updates | Updates required in OR and filed in other jurisdictions as informational. | Appendix B |
| 2025.009 RNW (5/2/24) | PLEXOS settings | Optimimization modeling and details of the PLEXOS modeling process provided in 1/25/24 and 3/14/24 PIMs. | Chapter 8 |
| 2025.010 UCARE (6/3/24) | Utah legislative sensitivity case | Legislative impacts and proposed sensitivities discussed in August and September PIMs. | Appendix M |
| 2025.011 UEC (6/10/24) | Climate modeling, thermal resources options, water resources | State policy updates discussed in August, no changes to water use and management, broad range of geothermal cost scenarios being considered. | Appendix G; Chapter 10 |
| 2025.012 UAE (6/24/24) | Errors in 2023 IRP Chapter 6 tables | Acknowledgement of errors and where to view Excel files for tables. | Chapter 6 |
| 2025.013 Emma Verhamme (6/24/24) | Coal retirement in UT | 2023 IRP Update assumptions locked before SB-224 passed; legislative impacts and proposed sensitivites for the 2025 IRP to be discussed in August and September PIMs. | Chapter 3 |
| 2025.014 Joan Entwistle (4/23/24) | 2023 IRP Update drivers | Discussion of inputs and assumptions to continue through 2025 IRP PIMs. | Chapter 8; Chapter 10 |
| 2025.015 Sierra Club (4/29/24) | Methane and gas energy sources | Scenarios included a CO2 price and the social cost of greenhouse gases. PLEXOS endogenously determined coal retirement dates and new renewable resources. | Chapter 8 |
| 2025.016 PRBRC (4/30/24) | Compliance with EPA greenhouse gas emissions rules | PacifiCorp will complete holistic modeling for EPA's GHG Rule, including compliance scenarios, descriptions, charts, and details as part of the 2025 IRP. | Chapter 3 |
| 2025.017 OPUC (7/3/24) | Distributed generation study, transmission modeling, recommendations from analysis of 2023 IRP Update | Responses provided to each detailed question by subject. | Chapter 6; Chapter 7; Chapter 8; Chapter 10 |

## Table C.1 – Stakeholder Feedback Form Summary (continued)

| SFF # | Request Topic | PacifiCorp Reply | Reference |
|---|---|---|---|
| 2025.018 OCA (7/19/24) | Wildfire risk, regional and interregional transmission | Wildfire-related costs are part of the SCGHG scenario. Regional and interregional transmission plans are developed through the NorthernGrid regional planning process. | Chapter 5; Chapter 8 |
| 2025.019 OCA (7/19/24) | Chehalis natural gas plant and WA Climate Commitment Act cap-and-invest program, modeling scenarios | PacifiCorp considers the cost and dispatch impacts of the WA CCA cap-and-invest program. | Chapter 8 |
| 2025.021 FPA (7/9/24) | Configuration details for PLEXOS modeling exercises | Table of PLEXOS Production Settings provided. | Chapter 8 |
| 2025.022 SLC (7/29/24) | PLEXOS model variant | The IRP is based on proxy resource costs and related assumptions that are generic and intended to be broadly applicable. | Chapter 8 |
| 2025.023 NPE (8/9/24) | Non-emitting peakers - Hydrogen fuel availability | Responses provided to each request. | Chapter 7 |
| 2025.024 NPE (8/9/24) | Candidate resource costs | Resource cost adjustments explained. | Chapter 7 |
| 2025.025 NPE (8/9/24) | Carbon capture storage | Descitpion of FEED study role; CCS assumptions and status. | Chapter 7 |
| 2025.026 VSO (8/9/24) | Distributed generation study, sensitivities | Please see responses to individual questions in the form. | Chapter 6 |
| 2025.027 VSO (8/9/24) | Tax Credits | Modeling accounts for tax credits and bookend sensitivities will cover unknown magnitudes outside of PacifiCorp control. | Chapter 8 |
| 2025.028 UCARE (8/30/24) | PLEXOS modeling and differential coal quality cost impacts | Modeling accounts for coal costs on a BTU-adjusted basis. | Chapter 8 |
| 2025.029 UCE (8/9/24) | Modeling coal costs and risks in 2025 IRP planning process | Description of coal reporting, supply assumptions, and risks. | Chapter 8 |
| 2025.30 Katie Pappas (8/13/24) | Proposed RMP rate increase in Utah | The IRP process selects the least-cost, least-risk portfolio under given conditions. Renewable energy is expected to make up an increasing proportion of energy generated by the PacifiCorp system over time. | Chapter 8 |
| 2025.031 Jane Myers (8/13/24) | Utah rate increase | The IRP process selects the least-cost, least-risk portfolio under given conditions. Renewable energy is expected to make up an increasing proportion of energy generated by the PacifiCorp system over time. | Chapter 8 |
| 2025.032 Sara Kenney (8/14/24) | Carbon Dioxide Emissions | PacifiCorp is committed to achieving emissions reduction targets as required by state and federal regulatory obligations and welcomes the development of alternative fuel sources that can provide a similar level of system flexibility as traditional thermal resources at reduced emissions rates. | Chapter 8 |
| 2025.035 WEA (8/20/24) | "Business as Usual" reference case | Defined and clarified the case requirement from Utah investigative order. | Chapter 8 |
| 2025.036 SC (8/27/24) | Numerous topics including DSM, granularity, Energy Infrastructure Reinvestment, Federal legislation, resource availability | Each topic addressed in terms of 2025 IRP modling, reporting and access to materials. | Chapter 8 |
| 2025.037 UCARE (8/30/24) | Utah state legislative actions | Will be addressed in the September 25-26 public input meeting. | Chapter 3 |
| 2025.039 WRA (9/9/24) | Information and market variant request | Further information about the origin of the Wyoming market treatment and WRAP. | Chapter 8 |
| 2025.040 RNW (9/11/24) | IRP transmission planning | Please see responses to individual questions in the form. | Chapter 8 |
| 2025.041 Nathan Strain (9/20/24) | Nuclear & geothermal development in Utah | Sensitivity studies planned for nuclear and geothermal costs. | Chapter 7 |
| 2025.042 FPA (9/23/24) | Request for LT plan settings | Not available; to be provided with the workpapers in the IRP filing. | Chapter 8 |
| 2025.044 SC (9/28/24) | CCS modeling constraint | Please see responses to individual questions in the form. | Chapter 8 |
| 2025.045 UCE (11/7/24) | Conservation potential assessment modeling | Latest UT code plus amemdments being used in CPA. | Chapter 7 |
| 2025.046 UCE (11/7/24) | Requests energy efficiency & demand response data from past filings | Please see responses to individual questions in the form. | Not included in the 2025 IRP; refers to 2023 IRP and 2023 IRP Update |

### Table C.1 – Stakeholder Feedback Form Summary (continued)

| SFF # | Request Topic | PacifiCorp Reply | Reference |
|---|---|---|---|
| 2025.048 UCE (12/17/24) | Sensitivity targeting 85% reduction in PaciiCorp emissions by 2032 using 2005 baseline | Study will be run if time and resources allow. | Chapters 8; Chapter 9 |
| 2025.049 UAEU (1/8/25) | Clarifying composition of resource and portfolio tables. | Additional information added for the final IRP. | Chapter 7; Chapter 9 |
| 2025.050 UCE (1/14/25) | Emissions sources and drivers | Emissions include purchases; rate given, explanation in Appendix A. | Chapter 9; Appendix A |
| 2025.52 WEA (1/15/25) | Load forecasting, resource adequacy | Some load considerations are not in the scope of the IRP. Market purchases are restricted during critical peaks more than in past IRPs. | Chapter 1; Chapter 5; Chapter 7; Appendix A |
| 2025.053 SC (1/16/25) | Preferred portfolio selection of MN vs MR, coal pricing, HB 2021 compliance, CCS costs | Topics addressed in the Jnauary 22-23, 2025 PIM. Coal pricing in final workpapers. Final filing will include coal assumptions, CCS, and a new CEP appendix as a bridge to the CEP filing. | Chapter 7; Chapter 9; Appendix Q |
| 2025.54 WYC (1/15/25) | Draft table clarifications, transmission-only customers, load forecast components, PLEXOS model data | Clarifications given will also be included in the final IRP filing. Some special contracts are considered in the load forecast. PLEXOS .xml data is confidential. | Chapter 6; Appendix A |
| 2025.55 DPU (1/24/25) | Study request which excludes 100-hour iron-air batteries | Request is under consideration. | Chapter 8; Chapter 9 |
| 2025.56 UCE (1/25/25) | Concerns regarding lack of geothermal selections, request for sensitivity | Geothermal parameters defined. Request for a counterfactual study is under consideration. | Chapter 7 |
| 2025.57 UCE (1/25/25) | Concerns regarding DSM variability and selection over the planning horizon | All resources are selected on a technology-agnostic competitive basis in the optimization process. | Chapter 7; Chapter 8 |
| 2025.62 RNW (2/10/25) | Questions regarding interactions of WRAP, transmission and resource selections | Please see responses to individual questions in the form. | Chapter 8 |
| 2025.63 UCE (2/10/25) | PTC interactions with study horizon in plain modeling | PTCs will be modeled to taper off after five year to mitigate the observed clustering of resources in 2036. | Chapter 7; Chapter 8; Chapter 9 |
| 2025.64 IEA (2/10/25) | Transmission topology, upgrades and modeling | Transmission options are available for selection by the model. Please see responses to individual questions in the form. | Chapter 7; Chapter 8; Chapter 9 |
| 2025.69 SC (2/20/25) | Request for sensitivity, PLEXOS request for input file | Please see responses to individual questions in the form. | N/A |
| 2025.71 Jeremy Rishe (3/03/25) | Encouragement to develop solar, storage and transmission | PacifiCorp is exploring divese options for customers. | Chapter 7 |

## Requested Additional Studies

Stakeholder feedback forms provided more than 50 requests for data and modeling changes or considerations in the 2025 IRP development cycle. These requests fell into three broad categories:

1. Requests for data inputs or modeling work that was already planned or required.
2. Requests to add detailed legislation, technologies or special interests to base inputs and assumptions for all studies.
3. Requests for additional cases studies, either variants or sensitivities.

There were eight requests in the third category, seeking additional studies. A review of these requests indicated synergies with cases already slated for analysis (such as a low cost of renewables study and a high use of IRA/IIJA funding). Advances in post-model reporting have increased the amount of information available from every study, making some additional studies unnecessary.

The eight specifically requested cases are summarized below.

1. Utah Legislative Sensitivity Case (SFF #10, Utah Citizens Advocating Renewable Energy): The 2025 IRP includes several cases that would help inform what a portfolio may look like if new resources and transmission are required for Utah as a consequence of legislative activity, specifically the Low Cost Renewables and No Coal 2032 studies.

2. Customer Choice Variant (SFF #22, Salt Lake City Corp): This request proposed a variant based on amounts of potential resource availability in an earlier timeframe than currently allowed in IRP modeling. The additional resources would be associated with programs and tariffs that could bring resources into commercial operation prior to 2028. PacifiCorp does not foreclose the opportunity for such projects; however, the Integrated Resource Plan (IRP) is based on proxy resource costs and related assumptions that are generic and intended to be broadly applicable.

3. Cluster Transmission Cost Reduction Variant (SFF #36, Sierra Club): This is a scenario in which transmission network upgrade costs in Cluster Areas 1, 2, 4, 12, and 14 are reduced by 30 percent. This narrowly defined scenario is better considered under the umbrella of a studies with broader application, such as the Low Cost Renewables case, which has the net effect of reducing the cost of resource-plus-transmission on an aggrgeate basis, driving a similar outcome.

4. EIR Financing Variant (SFF #36, Sierra Club): This requested variant is represented by the Low Cost Renewables case.

5. Hunter/Huntington SCR Variant (SFF #36, Sierra Club): This variant would implement SCR or SNCR at all five Hunter and Huntington Units. Emissions reductions from these technologies are available in practice, and the effective cost per ton of potential emissions reductions from installation of SNCR or SCR can be calculated from the model results. Because both SNCR and SCR technology have little impact on resource operating parameters such as heat rate and maximum output, there would be little impact on system dispatch from including those options in the model. Note that CCS installation is assumed to include SCR technology.

6. Wyoming Market Removal Variant (SFF #39, Western Resource Advocates): Assumes there is no access to the presumed Wyoming market. This study request is not addressed given that in the 2025 IRP it is already assumed that there is no market availability during peak hours, and all integrated portfolios must include sufficient generating and storage resources to be compliant with WRAP-based planning reserve margins. Thus, integrated portfolios are already required to meet reliability goals without the use of markets.

7. Declining Market Availability Variant (SFF #39, Western Resource Advocates): Assumes there is no access to the presumed Wyoming market, and market access declines to 25% of current assumption over 5 years. This study request is not addressed for the same reasons given in the above discussion of the Wyoming Market Removal Variant request, above.

8. Early Renewable Availability (SFF #69, Sierra Club): Conduct a sensitivity that includes a commercial operation date of 2026 for an initial tranche of solar, wind, and battery storage resources that equate to the AS2022 RFP. This study request is outside of the proxy-based scope of the 2025 IRP.

## Published Stakeholder Feedback Forms

The pages below include all of the publicly available feedback forms received by PacifiCorp in the 2025 IRP cycle at the time of this writing. Feedback forms and PacifiCorp's responses can also be found via the following link:

https://www.pacificorp.com/energy/integrated-resource-plan/comments.html

# PacifiCorp - Stakeholder Feedback Form (001)

## 2023 Integrated Resource Plan

PacifiCorp (the Company) requests that stakeholders provide feedback to the Company upon the conclusion of each public input meeting and/or stakeholder conference calls, as scheduled. PacifiCorp values the input of its active and engaged stakeholder group, and stakeholder feedback is critical to the IRP public input process. PacifiCorp requests that stakeholders provide comments using this form, which will allow the Company to more easily review and summarize comments by topic and to readily identify specific recommendations, if any, being provided. Information collected will be used to better inform issues included in the 2023 IRP, including, but not limited to the process, assumptions, and analysis. In order to maintain open communication and provide the broader Stakeholder community with useful information, the Company will generally post all appropriate feedback on the IRP website unless you request otherwise, below.

Date of Submittal 2024-01-11


*Name: Peter Gross Title:

*E-mail: orcabay@sisna.com Phone:

*Organization: Customer of RMP

Address: 643 Dragonfly TRL

City: Moab State: UT Zip: 84532


Public Meeting Date comments address: ☐ Check here if not related to specific meeting

List additional organization attendees at cited meeting:

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.

Nuclear power

☐ Check here if you do **not** want your Stakeholder feedback and accompanying materials posted to the IRP website.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.

Frankly, I was astonished to read that Rocky Mountain Power is contemplating replacing coal plants in Emery County with small nuclear reactors reactors. The nuclear industry has a half century history of massive cost overruns and multi-year construction delays of its own making. The nuclear industry has tried to reinvent itself for at least a quarter century. All four of the only nuclear reactor construction starts in the U.S. this century fell a decade behind schedule and suffered multi-billions in cost overruns. Virgil C Summer Units 2 and 3 were simply abandoned. The nuclear industry gravitated to larger capacity reactors from the outset for economic reasons. This is not unique to the United States. Flamanville Unit 3 in France and Olkiluouto Unit 3 in Finland have both come in triple to quadruple the already expensive original cost estimates while falling at least a decade behind schedule. So called SMRs remain unproven with a dubious future. Meanwhile, wind and especially solar costs continue to plummet. I urge RMP not to gamble on the nuclear folly and follow through with its wind and solar plans.

**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.

https://www.energymonitor.ai/power/weekly-data-renewables-overtake-nuclear-in-global-electricity-mix/?cf-view https://www.colorado.edu/cas/2022/04/12/even-china-cannot-rescue-nuclear-power-its-woes#:~:text=This%20decline%20is%20a%20result%20of%20nuclear%20power%E2%80%99s,electric%20grid%E2%80%94and%20they%20cost%20a%20lot%20to%20operate.
https://en.wikipedia.org/wiki/List_of_canceled_nuclear_reactors_in_the_United_States#Cancelled_nuclear_reactors

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https://en.wikipedia.org/wiki/Flamanville_Nuclear_Power_Plant#Unit_3
https://en.wikipedia.org/wiki/Olkiluoto_Nuclear_Power_Plant#Unit_3

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**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.

PacifiCorp Response 1/22/24:

Thank you for participating in the PacifiCorp 2025 IRP stakeholder process. Nuclear resources considered in the 2023 IRP have been intentionally limited to years outside of the action plan window with the understanding that while nuclear is an existing fuel technology, the Natrium project has a long lead time that requires continued evaluation of its potential. Ongoing negotiations are commercially sensitive, and any future contracts will be structured to minimize risks and costs for PacifiCorp's customers.

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Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com

Thank you for participating.

* Required fields

# **PacifiCorp - Stakeholder Feedback Form** (003)

## 2025 Integrated Resource Plan

PacifiCorp (the Company) requests that stakeholders provide feedback to the Company upon the conclusion of each public input meeting and/or stakeholder conference calls, as scheduled. PacifiCorp values the input of its active and engaged stakeholder group, and stakeholder feedback is critical to the IRP public input process. PacifiCorp requests that stakeholders provide comments using this form, which will allow the Company to more easily review and summarize comments by topic and to readily identify specific recommendations, if any, being provided. Information collected will be used to better inform issues included in the 2025 IRP, including, but not limited to the process, assumptions, and analysis. In order to maintain open communication and provide the broader Stakeholder community with useful information, the Company will generally post all appropriate feedback on the IRP website unless you request otherwise, below.

Date of Submittal 2024-05-07

*Name: Will Mulhern                Title:

*E-mail: William.Mulhern@puc.oregon.gov                Phone: (503) 385 - 3294

*Organization: Oregon Public Utility Commission

Address:

City:                State:                Zip:

Public Meeting Date comments address: 05-02-2024                ☐ Check here if not related to specific meeting

List additional organization attendees at cited meeting: JP Batmale, Sudeshna Pal, Kim Herb, Abe Abdallah, Isaac Kort-Meade

*__IRP Topic(s) and/or Agenda Items:__ List the specific topics that are being addressed in your comments.
Modeling inputs and scenarios

☐ Check here if you do **not** want your Stakeholder feedback and accompanying materials posted to the IRP website.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.
Can PacifiCorp list at the next public input meeting the exact list of inputs and scenarios that it plans to lock down in September? Can this list be released before the next public input meeting to support discussion? At which public input meeting will stakeholders have the chance to provide input on which scenarios will be used?

**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.

**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.
OPUC Staff recommends PAC specifically outline the inputs and scenarios it will be locking down in its modeling in September, provide these to stakeholders in advance of a public input meeting, and allow for discussion of these inputs and scenarios at a public input meeting.

**PacifiCorp Response 5/7/2024:**

For a list of anticipated inputs and assumptions to be discussed at future public input meetings, please refer to slide thirty-four from PacifiCorp's first 2025 IRP Public Input Meeting on January 25, 2024. The Company is rearranging the cadence of upcoming public input meetings to adapt to the January draft IRP requirement, and a revised schedule of topics will be presented at the next meeting to be held June 26-27, 2024. The agenda is intended to cover all data and assumptions development and methodologies, all of which is intended to be locked in September. The Company is also

* Required fields

adding an additional public input meeting in July to aoccomodate materials to be covered. The added meeting will be announced in the upcoming invitation to the June meeting.

The Company looks forward to your participation at upcoming meetings.

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Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com

Thank you for participating.

* Required fields

# PacifiCorp - Stakeholder Feedback Form (004)

## 2025 Integrated Resource Plan

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Date of Submittal 2024-05-06


*Name: Shannon Anderson

Title:

*E-mail: sanderson@powderriverbasin.org

Phone:

*Organization: Powder River Basin Resource Council

Address: 934 N. Main St.

City: Sheridan State: WY Zip: 82801


Public Meeting Date comments address: 05-02-2024 ☒ Check here if not related to specific meeting

List additional organization attendees at cited meeting:

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.
2023 IRP Update

☐ Check here if you do **not** want your Stakeholder feedback and accompanying materials posted to the IRP website.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.
At the May 2, 2024 IRP meeting, PacifiCorp representatives stated that there is an "oral agreement" in place with TerraPower such that PacifiCorp customers will not be charged any costs related to the Natrium nuclear power plant. Please explain why the company feels an "oral agreement" is sufficient for this purpose and explain the details of such agreement - who made it? when was it made? was it further represented by any writing or more formal conditions or agreements between the parties? Please also explain what "costs" were included in the agreement - construction costs? initial fuel costs? testing and analysis costs? regulatory costs? or does it also include operating and maintenance costs once the Natrium plant is operational and serving customers? Please also explain if it is PacifiCorp's understanding that the Natrium nuclear power plant will serve PacifiCorp customers exclusively as is represented in the 2023 IRP and previous IRPs or whether TerraPower plans to operate it as a merchant plant that sells power to PacifiCorp but not exclusively? Please see the Inside Climate News Story linked below that says the power will serve California - is that statement made simply because of the EIM or because TerraPower plans to sell directly to customers in California?

**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.
https://insideclimatenews.org/news/04052024/wyoming-terrapower-nuclear-plant/

**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.

* Required fields

```
PacifiCorp should identify new/amended action items for the 2025 IRP Action Plan to
ensure protection of ratepayers from unjust costs and expenses associated with the
Natrium Nuclear Power Plant.
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**PacifiCorp Response 5/8/2024:**

From the onset, PacifiCorp's engagement with TerraPower has been based on the understanding that Natrium demonstration project must be cost effective for our customers. This was emphasized in a June 2021 news release, which is available here: TerraPower, Wyoming Governor and PacifiCorp announce efforts to advance nuclear technology in Wyoming

In this new release, then president and CEO of Rocky Mountain Power, Mr. Gary Hoogeveen is quoted:

> "We are currently conducting joint due diligence *to ensure this opportunity is cost-effective for our customers* (emphasis added) and a great fit for Wyoming and the communities we serve."

Despite the inclusion of the Natrium demonstration project in the preferred portfolio, PacifiCorp, as of now, has not entered into any binding contractual agreements with TerraPower concerning the Natrium Project. The Natrium project has a long lead time that requires continued evaluation of its potential. Ongoing negotiations are commercially sensitive, and any future contracts will be structured to minimize risks and costs for PacifiCorp's customers, based on the specific costs and operational details of a potentially binding agreement, once one is available for consideration. PacifiCorp is not aware of any plans for TerraPower to sell output from the Natrium to customers in California.

The 2025 IRP Action Plan related to the Natrium demonstration project will be updated accordingly.

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Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com

Thank you for participating.

* Required fields

# **PacifiCorp - Stakeholder Feedback Form** (005)

## 2025 Integrated Resource Plan

PacifiCorp (the Company) requests that stakeholders provide feedback to the Company upon the conclusion of each public input meeting and/or stakeholder conference calls, as scheduled. PacifiCorp values the input of its active and engaged stakeholder group, and stakeholder feedback is critical to the IRP public input process. PacifiCorp requests that stakeholders provide comments using this form, which will allow the Company to more easily review and summarize comments by topic and to readily identify specific recommendations, if any, being provided. Information collected will be used to better inform issues included in the 2025 IRP, including, but not limited to the process, assumptions, and analysis. In order to maintain open communication and provide the broader Stakeholder community with useful information, the Company will generally post all appropriate feedback on the IRP website unless you request otherwise, below.

Date of Submittal 2024-05-06

*Name: Shannon Anderson Title:

*E-mail: sanderson@powderriverbasin.org Phone:

*Organization: Powder River Basin Resource Council

Address: 934 N. Main St.

City: Sheridan State: WY Zip: 82801

Public Meeting Date comments address: 05-02-2024 ☒ Check here if not related to specific meeting

List additional organization attendees at cited meeting: Shannon Anderson

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.
2023 IRP Update

☐ Check here if you do **not** want your Stakeholder feedback and accompanying materials posted to the IRP website.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.
At the May 2, 2024 PIM it was stated by PacifiCorp representatives that the preferred portfolio selection of carbon capture at Bridger Units 3&4 is unachievable. As such, we request PacifiCorp to issue an errata document to the 2023 IRP Update that explains this error to regulators, stakeholders, and the power plant community. Please also explain how these incorrect results are being addressed within the scope of the 2025 IRP for load and resource balance assumptions.

**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.

**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.
See above. We request an errata be issued related to Bridger 3&4. Thank you.

**PacifiCorp Response (5/16/24):**

A change in assumptions regarding the timing of implementation of carbon capture on Jim Bridger 3 & 4 occurred after the results of the 2023 integrated resource plan update were produced. It is not practical to issue an errata for model assumptions that change after an IRP or an update is completed. As is the case with all assumptions, assumptions related to carbon capture at Bridger Units 3 and 4 will be refreshed for the 2025 IRP.

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Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com

Thank you for participating.

* Required fields

# PacifiCorp - Stakeholder Feedback Form (006)
## 2023 Integrated Resource Plan

PacifiCorp (the Company) requests that stakeholders provide feedback to the Company upon the conclusion of each public input meeting and/or stakeholder conference calls, as scheduled. PacifiCorp values the input of its active and engaged stakeholder group, and stakeholder feedback is critical to the IRP public input process. PacifiCorp requests that stakeholders provide comments using this form, which will allow the Company to more easily review and summarize comments by topic and to readily identify specific recommendations, if any, being provided. Information collected will be used to better inform issues included in the 2023 IRP, including, but not limited to the process, assumptions, and analysis. In order to maintain open communication and provide the broader Stakeholder community with useful information, the Company will generally post all appropriate feedback on the IRP website unless you request otherwise, below.

Date of Submittal 2024-05-03


*Name: Katie Chamberlain
Title:
*E-mail: katherine@renewablenw.org
Phone:
*Organization: Renewable Northwest
Address:
City: State: Zip:


Public Meeting Date comments address: 05-02-2024 ☒ Check here if not related to specific meeting

List additional organization attendees at cited meeting:

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.
Distributed Generation Study

☐ Check here if you do **not** want your Stakeholder feedback and accompanying materials posted to the IRP website.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.
At the May 2 public input meeting, PacifiCorp and its consultant DNV discussed the methodology and assumptions behind the distributed generation (DG) study. The goal of the study is to estimate the market potential for DG resources by customer segment and by state across the 20-year planning horizon. The study uses three different scenarios: a base case, a low adoption scenario, and a high adoption scenario. It\u0019s important that the forecast is as accurate as possible given that the results will inform the 2025 IRP. Meeting participants also discussed the need to ensure that the low, base, and high DG adoption scenarios actually presented different possible futures, and PacifiCorp reiterated that the high case should result in materially higher adoption rates than the base case. It is unclear if the current assumptions will have that effect. RNW is following up on a few of the questions we posed in the meeting to better understand some of the assumptions behind the study.  Why did DNV/PacifiCorp choose to use the average of the \u0018conservative\u0019 and \u0018moderate\u0019 NREL ATB cost forecasts for the base DG adoption case? NREL\u0019s \u0018moderate\u0019 forecast is the expected level of technology innovation, which could be a more appropriate assumption for the base case. The DNV consultant suggested that he could connect with PacifiCorp to provide documentation on the selection of these cases, which we would appreciate.  Why did DNV/PacifiCorp choose to use the \u0018moderate\u0019 NREL ATB cost forecast for the high DG adoption case? It may be more appropriate to use NREL\u0019s \u0018advanced\u0019 forecast for this scenario to sufficiently capture expected adoption levels if technology costs decline more rapidly. As above, we would appreciate any further reasoning or documentation on the selection of this cost forecast. Why did DNV/PacifiCorp use the base case assumption (\u001Capplicable state and federal incentives based on current legislation\u001D) for the high DG adoption scenario, instead of assuming a higher level of incentives or an extension of existing incentives?

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**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.

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**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.

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**PacifiCorp Response (5/23/24):**

Thank you for your comments and feedback on the Distributed Generation (DG) Study. PacifiCorp agrees that it is important to develop the most accurate forecast for the 2025 IRP ensuring that variables informing DG adoption are accurately represented in our modeling. To the extent practical, DNV/PacifiCorp is working to improve modeling by incorporating the most recent adoption data, export rates, and relevant stakeholder feedback into base, low, and high cases in the modeling approach. Additionally, during the upcoming June 26-27th public input meeting we will share the study's specific assumptions for each case based on feedback from stakeholders. PacifiCorp responds as follows to the questions raised by RNW:

- **Stakeholder Question 1:** RNW is following up on a few of the questions we posed in the meeting to better understand some of the assumptions behind the study. Why did DNV/PacifiCorp choose to use the average of the conservative and moderate NREL ATB cost forecasts for the base DG adoption case?
- **Response 1:** DNV reviewed the cost forecasts in the NREL ATB data and found that the moderate cost decline forecast for solar PV was more aggressive than DNV's internal national cost models and what the market has experienced historically (~10 years). Recent cost increases or a general leveling of cost declines also adds to this assumption. The technology cost forecast used in the DG study base case has a ~35% price decrease through 2035, as opposed to the ~50% decrease forecasted in the NREL moderate case.
- **Question 2:** Why did DNV/PacifiCorp choose to use the NREL ATB cost forecast for the high DG adoption case?
- **Response 2:** DNV/PacifiCorp used the moderate NREL ATB cost forecast for the high scenario to maintain consistency with the other scenarios. The high scenario in this study is more focused on other market factors that could stimulate market growth and adoption, which are contained in the model's adoption parameters. These factors are changed in the high scenario to reduce market barriers over time and simulate the effects of a wide array of factors, which could also include components of technology cost. Moving forward, DNV and PacifiCorp will evaluate whether to incorporate a more aggressive NREL ATB cost forecast to inform the high scenario; this may be represented by using either advanced ATB cost forecast or a blend of the advanced and moderate ATB cost forecasts.
- **Question 3:** Why did DNV/PacifiCorp use the base case assumption (state and federal incentives based on current legislation) for the high DG adoption scenario, instead of assuming a higher level of incentives or an extension of existing incentives?
- **Response 3:** PacifiCorp elected to the use the base case assumption for federal and state tax incentives for all scenarios as these assumptions are not easily predictable and challenging to develop trends around. Therefore, the company believes it is more appropriate to look at other variables to inform the high and low case as these variables seem more likely to change in the near-term.

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Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com

Thank you for participating.

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# PacifiCorp - Stakeholder Feedback Form (007)

2025 Integrated Resource Plan

PacifiCorp (the Company) requests that stakeholders provide feedback to the Company upon the conclusion of each public input meeting and/or stakeholder conference calls, as scheduled. PacifiCorp values the input of its active and engaged stakeholder group, and stakeholder feedback is critical to the IRP public input process. PacifiCorp requests that stakeholders provide comments using this form, which will allow the Company to more easily review and summarize comments by topic and to readily identify specific recommendations, if any, being provided. Information collected will be used to better inform issues included in the 2025 IRP, including, but not limited to the process, assumptions, and analysis. In order to maintain open communication and provide the broader Stakeholder community with useful information, the Company will generally post all appropriate feedback on the IRP website unless you request otherwise, below.

Date of Submittal 2024-05-03

*Name: Katie Chamberlain Title:

*E-mail: katherine@renewablenw.org Phone:

*Organization: Renewable Northwest

Address:

City: State: Zip:

Public Meeting Date comments address: ☐ Check here if not related to specific meeting

List additional organization attendees at cited meeting:

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.

Renewable resource cost estimates

☐ Check here if you do **not** want your Stakeholder feedback and accompanying materials posted to the IRP website.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.

In our comments on PacifiCorp\u0019s 2023 IRP, RNW identified that PacifiCorp\u0019s overnight capital cost forecast for renewable resources is substantially higher than forecasts used by PGE and the CPUC. PacifiCorp used cost assumptions developed by WSP, which were primarily informed by the NREL ATB, and then made adjustments based on the Company\u0019s experience. In reply comments, PacifiCorp explained that: \u001Cthe cost forecasts in WSP\u0019s report were developed before PacifiCorp witnessed the impact of recent tighter trade tariffs and inflation on the utility scale market. Upon observing those impacts PacifiCorp adjusted the cost forecasts to reflect what was observed in the market in 2022.\u001D Pacificorp used the same renewable resource cost estimates in the 2023 IRP Update, despite OPUC Staff and multiple parties expressing skepticism about their accuracy and requesting further explanation as to how PacifiCorp arrived at these estimates. RNW requests that PacifiCorp explain in greater detail why they made modifications to WSP\u0019s cost forecast and provide documentation of these changes. Specifically, RNW would like to understand how PacifiCorp observed changes in the market in 2022 and the methodology the Company used to increase the renewable resource cost forecast.  1. PacifiCorp states that they adjusted WSP cost forecast to reflect what was observed in the market in 2022.In particular, PacifiCorp witnessed the impact of recent tighter trade tariffs and inflation on the utility scale market. Can the Company explain how they witnessed and observed these changes in the market? 2. Are PacifiCorp renewable resource cost estimates based on bids the Company received in recent RFPs? If so, please provide documentation demonstrating higher average bid prices, the year in which those bids were received, and how those prices translate to the higher overnight capital costs reflected in PacifiCorp IRP.  Please note that we are not requesting individual bid prices, which are confidential; instead, we are requesting averages. 3. If the renewable resource cost estimates were not based on RFP bids, please provide the underlying

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quantitative information that justifies the increased renewable resource cost estimates.
4. How does PacifiCorp plan to forecast renewable resource costs for the 2025 IRP?

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**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.

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**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.

**PacifiCorp Response 5/23/24**:

Please note that the 2023 IRP and 2023 Update supply-side resource table does not present overnight cost but rather in-service cost for each resource. Please refer to the 2023 IRP Volume I, Chapter 7, and specifically Table 7.3 on page 189. The values presented include 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, owner’s contingency), and financial costs (allowance for funds used during construction (AFUDC), capital surcharge, property taxes and escalation during construction, if applicable).

Consequently, any comparison of third-party costs characterized as overnight costs will be lower than our in-service costs, which reflect the cost to our customers and not just the development costs.

Moreover, escalation is often another area where misaligned comparisons are made. Many third-party public sources present their costs in real terms and routinely are silent on escalation. We also present our in-service costs in real dollars, but also present and include nominal escalation forecasts. To ensure an apples to apples comparison is being made, both sets of data need to be adjusted for inflation to arrive at figures presented in the same year dollars for any given year that a comparison is being made.

1. Yes. Adjustments to the WSP and NREL cost forecast were grounded in actual project costs the company received. These initial adjustments were made to years when the company had actual cost data of real, proposed projects. Rather than drop immediately to the NREL/WSP pricing in later years, the costs were de-escalated over time to correspond to NREL starting in 2029 and converging with NREL in 2032. Please reference figure 5.3 in the 2023 IRP Update to see this escalation and de-escalation visually.
2. Generally, yes. PacifiCorp is preparing a slide on this topic for a future public input meeting which will cover the range of prices at which renewable resources are available in both the near and longer term.
3. N/A
4. As part of the conversation referenced in response to question 2, and as in past IRP public meetings, PacifiCorp will seek feedback on cost structures/forecasting and will be finalizing that plan as part of the 2025 IRP public input process.

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Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com

Thank you for participating.

* Required fields

# PacifiCorp - Stakeholder Feedback Form (008)
## 2025 Integrated Resource Plan

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Date of Submittal 2024-05-02


*Name: Nancy Kelly

Title:

*E-mail: nkelly@westernresources.org

Phone: (208) 704 - 0488

*Organization: Western Resource Advocates

Address: 307 W. 200 S. Suite 200

City: Salt Lake City State: UT Zip: 84101


Public Meeting Date comments address: 05-02-2024 ☒ Check here if not related to specific meeting

List additional organization attendees at cited meeting:

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.
IRP updates

☐ Check here if you do **not** want your Stakeholder feedback and accompanying materials posted to the IRP website.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.
Please identify which states require an IRP update. Provide the docket number and date of the order requiring the update, or if a state has planning rules, the rule and its requirement.

**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.

**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.

**PacifiCorp Response (5/16/24):**

Oregon Administrative Rule 860-027-0400(8) provides, in part, that "Each energy utility must provide an annual update on its most recently acknowledged IRP. The update must be submitted on or before the acknowledgment order anniversary date." PacifiCorp's IRP Update, submitted on April 1, 2024, in Oregon Public Utility Commission Docket No. LC 82, was filed in compliance with Oregon Administrative Rule 860-027-0400. PacifiCorp also submitted its IRP Update in other jurisdictions as an informational filing.

Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com

Thank you for participating.

* Required fields

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# PacifiCorp - Stakeholder Feedback Form (009)

## 2023 Integrated Resource Plan

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Date of Submittal: 2024-05-02


*Name: Jim Himelic

Title:

*E-mail: jhimelic@firstprinciples.run

Phone: 5209791375

*Organization: Renewables Northwest

Address:

City: State: Zip:


Public Meeting Date comments address: ☐ Check here if not related to specific meeting

List additional organization attendees at cited meeting:

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.

PLEXOS Settings

☐ Check here if you do **not** want your Stakeholder feedback and accompanying materials posted to the IRP website.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.

Renewable Northwest is requesting that Pacificorp address specific elements of their PLEXOS modeling process during an upcoming stakeholder meeting. The items of interest are divided into two main categories: Category 1: LT Plan Temporal Configuration Discuss step size and overlap; as well as any application of PLEXOS' rolling horizon feature. Review Chronology Method options: partial, fitted, sample. Examine Duration Curve Type and the number of blocks per curve.In addition, discuss what process Pacificorp takes in maximizing model accuracy with problem size (i.e. run times) Discuss what slicing method is activated and discuss the strengths and weaknesses between peak/off peak and weighted least squares. Discuss the use of global variables, such as slicing blocks and sampling years. Delve into expansion decisions regarding integer optimality: whether using LP or MILP, and details on the integerization horizon if MILP is used. Category 2: Performance Settings Evaluate solver selection, solver method, and MIP gap settings. Consider the use of solver tuning optimization software programs. Review parallelization settings and CPU hardware capabilities of PacifiCorp, including RAM, physical cores, and CPU speed. Additional topics related to the administering and running of the PLEXOS models will be discussed in future meetings.

**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.

**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.

Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com

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**PacifiCorp response (7/15/2024/2024):**

Thank you for your feedback and engagement in the Integrated Resource Planning process. The subject matter expertise and experience required to meaningfully engage in discussion concerning the requested technical details is beyond the scope of a public input meeting. PacifiCorp analysts and technical teams consider all of the above strategies in its technical implementation of PLEXOS and maintains an ongoing relationship with Energy Exemplar experts in order to balance and optimize model functionality.

PacifiCorp covered optimization modeling and details of the PLEXOS modeling process at the January 25, 2024 and March 14, 2024 Public Input Meetings. As explained in the March meeting, PacifiCorp has explored the suggested avenues and has been engaged specifically in ongoing efforts to improve LT model granularity and performance.

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# PacifiCorp - Stakeholder Feedback Form (010)

## 2023 Integrated Resource Plan

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Date of Submittal: 2024-06-03

*Name: Stanley Holmes
Title:

*E-mail: stholmes3@xmission.com
Phone:

*Organization: Utah Citizens Advocating Renewable Energy (UCARE)

Address:

City:
State: UT
Zip:

Public Meeting Date comments address: 05-02-2024

☒ Check here if not related to specific meeting

List additional organization attendees at cited meeting: See PacifiCorp 2025 IRP Public Input Meeting #3, May 2, 2024 attendees list.

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.
Transmission Selections and Coal Retirements; Utah Legislative Sensitivity Case

☐ Check here if you do **not** want your Stakeholder feedback and accompanying materials posted to the IRP website.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.
PacifiCorp's May 2, 2024 public input discussion raised questions about potential impacts of statutes issuing from the 2024 Utah Legislature session, to include Senate Bills 161, 224 and House Bills 48, 191. The new Utah laws could, within the 2025 IRP timeframe, make available to PacifiCorp new energy generation units within Utah and influence EGU retirement plans for PacifiCorp assets. One or more additional transmission lines might have to be considered. PacifiCorp is therefore urged to create a placeholder sensitivity within the 2025 IRP for analysis of Utah statute-related factors as they may arise.

**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.
https://le.utah.gov/~2024/bills/static/SB0161.html,
https://le.utah.gov/~2024/bills/static/SB0224.html,
https://le.utah.gov/~2024/bills/static/HB0048.html,
https://le.utah.gov/~2024/bills/static/HB0191.html

**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.
Recommend that PacifiCorp create a placeholder sensitivity case within the 2025 IRP for analysis of Utah statute-related factors as they may arise.

**PacifiCorp response (7/10/2024):**

* Required fields

Thank you for your feedback and suggestions as we prepare the 2025 IRP. Further discussion of legislative impacts and proposed sensitivities will be included in the upcoming August and September public input meetings as these potential impacts are considered.

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Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com

Thank you for participating.

* Required fields

# PacifiCorp - Stakeholder Feedback Form (011)

## 2023 Integrated Resource Plan

PacifiCorp (the Company) requests that stakeholders provide feedback to the Company upon the conclusion of each public input meeting and/or stakeholder conference calls, as scheduled. PacifiCorp values the input of its active and engaged stakeholder group, and stakeholder feedback is critical to the IRP public input process. PacifiCorp requests that stakeholders provide comments using this form, which will allow the Company to more easily review and summarize comments by topic and to readily identify specific recommendations, if any, being provided. Information collected will be used to better inform issues included in the 2023 IRP, including, but not limited to the process, assumptions, and analysis. In order to maintain open communication and provide the broader Stakeholder community with useful information, the Company will generally post all appropriate feedback on the IRP website unless you request otherwise, below.

Date of Submittal: 2024-06-10


*Name: Monica Hilding — Title: Chair

*E-mail: mohilding@gmail.com — Phone: 8016805303

*Organization: Utah Environmental Caucus

Address: 155 South Lincoln Street

City: Slc — State: UT — Zip: 84102


Public Meeting Date comments address: 06-26-2024 — ☒ Check here if not related to specific meeting

List additional organization attendees at cited meeting:

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.
Climate modeling,Thermal Resources options,Water Resources

☐ Check here if you do **not** want your Stakeholder feedback and accompanying materials posted to the IRP website.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.
1) Please update how RMP's lengthy delay of renewable and storage purchases could affect Utah Community Renewable Energy purchases --esp. with revisions under 2024 Utah Senate Bill 214-- and affect 2025 IRP horizon assumptions. 2) How is RMP-PacifiCorp taking water use into consideration for cooling the coal plants whose lives were recently extended in contravention of the 2023 IRP? 3) With RMP having filed deferred accounting orders with the Utah PSC for wildfire claims [Docket 23- 035-30] and rising insurance costs [23-035-40], respectively, and the rising insurance costs docket now moving forward, how much of the subsequent financial burden will Utah ratepayers have to shoulder alone and how much shared across PacifiCorp's grid? 4) How will geothermal advances recently demonstrated by the FORGE project be reflected as portfolio sensitivities for the 2025 IRP.

**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.
https://le.utah.gov/~2024/bills/static/SB0214.html,
https://pscdocs.utah.gov/electric/23docs/2303530/3298372303530n9-15-2023.pdf,
https://psc.utah.gov/2023/08/21/docket-no-23-035-40/,
https://www.sltrib.com/news/environment/2024/05/31/utah-lab-proves-it-pulling-heat/

**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.
Recommend a portfolio sensitivity for water consumption by power plants.

Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com

* Required fields

Thank you for participating.

PacifiCorp Response (7/15/24):

1. PacifiCorp expects to address state policy updates in its August 14-15 public input meeting as these matters are considered.

2. The Utah coal plant lives listed in the 2023 IRP Update preferred portfolio are the same as the dates for the same coal units that were listed in the 2021 IRP preferred portfolio. From a water use and management perspective, there have been no changes. RMP will therefore manage water consumption going forward as it has been in the past, relying on a collection of water resources and water rights.

3. The matter of insurance costs and their inclusion in rates is outside the scope of the IRP.

4. PacifiCorp is considering the broad range of geothermal cost scenarios presented in the National Renewable Energy Laboratory (NREL) 2024 Annual Technology Baseline (ATB). The Company will most likely model geothermal under the ATB's "Moderate Scenario" quoted below, and the "Mature Hydro/Flash" technology option which has the lowest cost and cost forecast, and the lowest uncertainty for the moderate scenario among the technology options. The Company recognizes that the "Advanced Scenario" for Enhanced Geothermal Systems (EGS) may become more cost competitive within the next decade; there is no plan to model that scenario at this time. However, planning for sensitivities and variants is a subject being addressed in the upcoming July 17-18 public input meeting and will also be addressed in subsequent meetings responsive to stakeholder feedback.

**Moderate Technology Innovation Scenario (Moderate Scenario):** Drilling advancements (e.g., doubled ROP and bit life from GeoVision baseline and reduced number of casing intervals and associated drilling materials) detailed as part of the GeoVision report (DOE, 2019) and EGS stimulation successes from DOE-funded EGS Collab and FORGE projects (Kneafsey et al., 2022); (Dupriest and Noynaert, 2024) and industry demonstration projects (Norbeck et al., 2023); (El-Sadi et al., 2024); (So et al., 2024) result in cost improvements that are fully achieved industrywide by 2035. Also, as part of 2024 ATB updates, this scenario assumes EGS power plants are built to a capacity of 40 megawatts (MW).

* Required fields

# PacifiCorp - Stakeholder Feedback Form (012)

## 2023 Integrated Resource Plan

PacifiCorp (the Company) requests that stakeholders provide feedback to the Company upon the conclusion of each public input meeting and/or stakeholder conference calls, as scheduled. PacifiCorp values the input of its active and engaged stakeholder group, and stakeholder feedback is critical to the IRP public input process. PacifiCorp requests that stakeholders provide comments using this form, which will allow the Company to more easily review and summarize comments by topic and to readily identify specific recommendations, if any, being provided. Information collected will be used to better inform issues included in the 2023 IRP, including, but not limited to the process, assumptions, and analysis. In order to maintain open communication and provide the broader Stakeholder community with useful information, the Company will generally post all appropriate feedback on the IRP website unless you request otherwise, below.

Date of Submittal 2024-06-24

*Name: Don Hendrickson
Title:
*E-mail: dhendrickson@energystrat.com
Phone: 8016521292
*Organization: Utah Association of Energy Users
Address: 111 E Broadway, Suite 1200
City: SLC State: UT Zip: 84111

Public Meeting Date comments address: ☐ Check here if not related to specific meeting

List additional organization attendees at cited meeting:

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.
Suspected Errors in IRP Document Tables - System Capacity Load and Resource Balance without Resource Additions

☐ Check here if you do **not** want your Stakeholder feedback and accompanying materials posted to the IRP website.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.
It appears that there are errors in the \u001CSystem Capacity Load and Resource Balance without Resource Additions\u001D tables in the 2023 IRP and the 2023 IRP Update. 2023 IRP: Table 6.12 appears to show incorrect data on two rows, West Obligation + Reserves and West Position. The apparent error occurs in years 2023 and 2024. We suspect this is a formula error in the underlying Excel file. 2023 IRP Update: Tables 4.2 and 4.3 appear to show incorrect data on two rows, West Obligation + Reserves and West Position. The apparent errors occur in years 2034 through 2042 in both tables 4.2 and 4.3. We suspect this is an error in putting the data into the main document. Please confirm the errors in the 2023 IRP and 2023 IRP Update or state why you believe the data in the above-referenced rows is correct. If you confirm the errors, please correct these errors in the 2025 IRP.

**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.

**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.
We also recommend that the Excel version of these tables be moved from the Confidential set of data to the Public set of data since the data is public in .pdf form already.

Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com

* Required fields

Thank you for participating.

**PacifiCorp response (7/10/2024):**

Thank you for your feedback and engagement in the Integrated Resource Planning process.

2023 IRP: PacifiCorp can confirm that there are errors in the West Obligation + Reserves and West Position rows in Table 6.12 for the years 2023 and 2024. These errors are the result of an incorrect formula in the underlying Excel file used to generate the table. For the years 2023 and 2024, the formula for West Obligation + Reserves erroneously added New Energy Efficiency to the Planning Reserve Margin instead of West Total obligation. The West Position formula was correct, but it used the incorrect data from the West Obligation + Reserves row for 2023 and 2024.

2023 IRP Update: PacifiCorp can confirm that there are errors in the West Obligation + Reserves and West Position rows for the years 2034 through 2042 in both Tables 4.2 and 4.3. There are identical errors in Tables 4.2 and 4.3 as a result of an incorrect formula in the underlying Excel file used to generate the part of the table displaying values from 2034 to 2042. The formula for West Obligation + Reserves incorrectly added New Energy Efficiency to the Planning Reserve Margin instead of West Total obligation. This incorrect value was then used in the West Position formula.

The Excel files used to create these tables are already available in the public data discs. To view the file used for the 2023 IRP tables, go to the public data disc posted on May 31st and use the following path: Chapters, Appendices, and Input Assumptions\Chapters and Appendix\CH6 - Load and Resource Balance\ (P)_Fig 6.2-6.7, Tables 6.11-6.12, 2023 IRP - L&R. To view the file used for the 2023 IRP Update tables, go to the public data disc posted on April 1st and use the following path: Chapters, Appendicies, and Input Assumptions\Chapters and Appendix\CH4 - Load and Resource Balance Update\(P)__PC_Table 4.2-3 6.4-5 Fig 4.3-4.4 2023 IRP Update - L&R.

PacifiCorp will verify that the System Capacity Load and Resource Balance without Resource Additions tables in the 2025 IRP do not replicate these errors.

* Required fields

# PacifiCorp - Stakeholder Feedback Form (013)

## 2023 Integrated Resource Plan

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Date of Submittal 2024-06-24

*Name: Emma Verhamme  Title:

*E-mail: emmascanlon4@gmail.com  Phone: (860) 324 - 2638

*Organization: (individual)

Address: 848 N Lafayette Drive

City: Salt Lake City  State: UT  Zip: 84116

Public Meeting Date comments address: 06-26-0204  ☒ Check here if not related to specific meeting

List additional organization attendees at cited meeting:

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.
Coal Retirement

☐ Check here if you do **not** want your Stakeholder feedback and accompanying materials posted to the IRP website.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.
How have new federal laws and Utah state laws shaped the IRP? Specifically, how has UT bill SB-224 affected the timeline for retirement of coal in Utah? Also, how does this bill affect the rate payer and the tax payer in Utah?

**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.
https://le.utah.gov/~2024/bills/static/SB0224.html

**Recommendations:**

PacifiCorp Response (7/10/2024):

Assumptions for PacifiCorp's 2023 IRP Update were locked down before SB-224 was passed, so it had no impact on the retirement dates of coal resources in Utah, for example. Further discussion of legislative impacts and proposed sensitivities for the 2025 IRP will be included in the upcoming August and September public input meetings as these potential impacts are considered.

Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com

Thank you for participating.

* Required fields

* Required fields

# PacifiCorp - Stakeholder Feedback Form (014)

## 2023 Integrated Resource Plan

PacifiCorp (the Company) requests that stakeholders provide feedback to the Company upon the conclusion of each public input meeting and/or stakeholder conference calls, as scheduled. PacifiCorp values the input of its active and engaged stakeholder group, and stakeholder feedback is critical to the IRP public input process. PacifiCorp requests that stakeholders provide comments using this form, which will allow the Company to more easily review and summarize comments by topic and to readily identify specific recommendations, if any, being provided. Information collected will be used to better inform issues included in the 2023 IRP, including, but not limited to the process, assumptions, and analysis. In order to maintain open communication and provide the broader Stakeholder community with useful information, the Company will generally post all appropriate feedback on the IRP website unless you request otherwise, below.

Date of Submittal 2024-04-23

*Name: Joan Entwistle Title:
*E-mail: joan.entwistle@gmail.com Phone: 9785494864
*Organization: self
Address: 8231 Meadowview Ct
City: Park City State: UT Zip: 84098

Public Meeting Date comments address: 05-02-2024 ☐ Check here if not related to specific meeting

List additional organization attendees at cited meeting:

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***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.
2023 Updates

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☐ Check here if you do **not** want your Stakeholder feedback and accompanying materials posted to the IRP website.

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***Respondent Comment:** Please provide your feedback for each IRP topic listed above.
Please address why RMP will regress to pre-2021 IRP levels of solar, wind, battery storage when these sources are now less expensive than other sources, and we will need to increasing the supply of electricity.

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**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.

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**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.
Please resume the 2022 all source RFP that was proposed in 2021.

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Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com

Thank you for participating.

**PacifiCorp Response (7/10/2024)**:

Thank you for your feedback and engagement in the Integrated Resource Planning process. For information regarding the drivers of change in amounts and timing of resources in recent IRP filings, please refer to the 2023 IRP and 2023 IRP Update, publicly accessible through this web link: Integrated Resource Plan (pacificorp.com)

* Required fields

PacifiCorp uses the Integrated Resource Planning process to select the least-cost, least-risk portfolio given prevailing conditions at the time of planning. The need to meet system demand in all hours means that the Company must consider factors beyond the cost of a resource, including whether the resource will reliably generate during peak load hours. Pages 6-7 of the 2023 IRP Update report that the preferred portfolio includes 3,749 megawatts of new solar online by 2037, 9,800 megawatts of new wind resources online by 2037, and more than 4,000 megawatts of new storage capacity online by 2037.

PacifiCorp anticipates the discussion of inputs and assumptions to continue throughout the 2025 IRP public input meeting series.

* Required fields

# PacifiCorp - Stakeholder Feedback Form (015)

## 2023 Integrated Resource Plan

PacifiCorp (the Company) requests that stakeholders provide feedback to the Company upon the conclusion of each public input meeting and/or stakeholder conference calls, as scheduled. PacifiCorp values the input of its active and engaged stakeholder group, and stakeholder feedback is critical to the IRP public input process. PacifiCorp requests that stakeholders provide comments using this form, which will allow the Company to more easily review and summarize comments by topic and to readily identify specific recommendations, if any, being provided. Information collected will be used to better inform issues included in the 2023 IRP, including, but not limited to the process, assumptions, and analysis. In order to maintain open communication and provide the broader Stakeholder community with useful information, the Company will generally post all appropriate feedback on the IRP website unless you request otherwise, below.

Date of Submittal 2024-04-29

*Name: Bill Stoye Title:

*E-mail: bstoye@xmission.com Phone:

*Organization: Sierra Club

Address:

City: State: Zip:

Public Meeting Date comments address: ☐ Check here if not related to specific meeting

List additional organization attendees at cited meeting:

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.
RMPs proposed customer lock into coal and methane gas energy sources.

☐ Check here if you do **not** want your Stakeholder feedback and accompanying materials posted to the IRP website.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.
Please divest from your continued use of coal powered electric generation. You know it's outdated and backwards, as well as costing us more and adding to dirtier air and well, you know, bolstering more climate change, in this needed time of renewable energy sources.

**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.

**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.

Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com

**PacifiCorp response (7/10/2024):**

Thank you for your feedback and engagement in the Integrated Resource Planning process.

PacifiCorp uses the Integrated Resource Planning process to select the least-cost, least-risk portfolio. In the 2023 Integrated Resource Plan (IRP) Update, coal plants were eligible for retirement any time after January 1, 2024. Wind, solar, hydro, and storage proxy resources were available for selection. Additionally, to represent the cost of emissions, scenarios were run that included a $CO_2$ price and the social cost of greenhouse gases. In consideration of all these factors

* Required fields

and others, the PLEXOS model endogenously determined coal retirement dates and procurement of new renewable resources.

Each Integrated Resource Plan is contingent on current legislation, market and resource cost, and other key elements of the planning environment. PacifiCorp anticipates the discussion of inputs and assumptions to continue throughout the 2025 IRP public input meeting series.

* Required fields

# PacifiCorp - Stakeholder Feedback Form (016)

## 2023 Integrated Resource Plan

PacifiCorp (the Company) requests that stakeholders provide feedback to the Company upon the conclusion of each public input meeting and/or stakeholder conference calls, as scheduled. PacifiCorp values the input of its active and engaged stakeholder group, and stakeholder feedback is critical to the IRP public input process. PacifiCorp requests that stakeholders provide comments using this form, which will allow the Company to more easily review and summarize comments by topic and to readily identify specific recommendations, if any, being provided. Information collected will be used to better inform issues included in the 2023 IRP, including, but not limited to the process, assumptions, and analysis. In order to maintain open communication and provide the broader Stakeholder community with useful information, the Company will generally post all appropriate feedback on the IRP website unless you request otherwise, below.

Date of Submittal 2024-04-30

*Name: Shannon Anderson Title:

*E-mail: sanderson@powderriverbasin.org Phone:

*Organization: Powder River Basin Resource Council

Address: 934 N. Main St.

City: Sheridan State: WY Zip: 82801

Public Meeting Date comments address: ☐ Check here if not related to specific meeting

List additional organization attendees at cited meeting:

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.
Compliance with EPA greenhouse gas emissions rules

☐ Check here if you do **not** want your Stakeholder feedback and accompanying materials posted to the IRP website.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.
We are requesting a slide prepared to show the implications of the EPA rule on greenhouse emissions for the coal units.

Please provide a chart to stakeholders showing implications for each coal unit based on the final EPA GHG rule. Please provide near-term and long-term implications based on operating condition impacts and/or CCS requirements. In the 2025 modeling, please model cost implications as well as alternative compliance options, such as earlier retirement dates.

**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.
EPA rule; coal unit retirement dates from 2023 IRP update preferred portfolio

PacifiCorp Response (7/12/2024):

PacifiCorp will complete holistic modeling for EPA's GHG Rule, including alternative compliance scenarios, descriptions, charts, and details as part of the 2025 IRP. The analysis will report implications of the rule for both near and long-term. Further discussion of legislative impacts and proposed sensitivities will be included in the upcoming August and September public input meetings as these potential impacts are considered.

* Required fields

Thank you for participating.

* Required fields

# PacifiCorp - Stakeholder Feedback Form (017)
## Integrated Resource Plan

PacifiCorp (the Company) requests that stakeholders provide feedback to the Company upon the conclusion of each public input meeting and/or stakeholder conference call, as scheduled. PacifiCorp values the input of its active and engaged stakeholder group, and stakeholder feedback is critical to the IRP public input process. PacifiCorp requests that stakeholders provide comments using this form, which will allow the Company to more easily review and summarize comments by topic and to readily identify specific recommendations, if any, being provided. Information collected will be used to better inform issues included in the IRP, including, but not limited to the process, assumptions, and analysis. In order to maintain open communication and provide the broader Stakeholder community with useful information, the Company will post appropriate feedback on the IRP website based on your selection below.

Date of Submittal 2024-07-03

*Name: Will Mulhern Title: Senior Utility Analyst
*E-mail: William.Mulhern@puc.oregon.gov Phone: (503) 385 - 3294
*Organization: Oregon Public Utility Commission
Address: 201 High St. SE, Suite 100
City: Salem State: OR Zip: 97301

Public Meeting Date comments address: 05-02-2024 ☒ Check here if related to specific meeting

List additional organization attendees at cited meeting:

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.
Some of the comments relate to specific topics from the May 2nd meeting, while the rest are recommendations from Staff\u0019s comments on the 2023 IRP Update

☒ Check here if you want your Stakeholder feedback and accompanying materials posted to the IRP website.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.
We would appreciate the response being posted publicly.

1. **May 2 Public Input Meeting - Distributed generation study:**
   a) Why is non-rooftop solar not considered in land use requirements?
      - **Reply**: Land-use requirement assumptions are inputs for all combinations of technology and customer types when estimating future adoption. These are based on a combination of existing system sizes for customer installations and technical feasibility factors. Non-rooftop solar is included in some larger commercial, industrial, and irrigation customer bins, but these overall sizes are capped because they also include assumptions for rooftop solar installations within the same customer type bins.

   b) What is the definition of the "diffusion model" used in this study?
      - **Reply**: The diffusion model is based on the Bass diffusion approach for technology adoption. This approach uses segment-level adoption rate curves, customer economic metrics, and historical customer adoption as inputs to forecast future adoption of distributed generation across the PacifiCorp territory. Please refer to the forecast methodology slide deck that was presented in the May 2 stakeholder meeting for more information.

   c) Does the model use different capacity factors based on location?

* Required fields

- o **Reply**: Yes. Capacity factors vary by state.

d) Will Oregon specific avoided costs – as reflected in UM 1893 Phase II - be used in the DSM forecast for the 2025 IRP? If not, will the updated EE avoided costs from UM 1893 be used in the CEP and if so, how?

- o **Reply**: No, the 2025 IRP does not use the avoided costs developed in UM-1893, though it does incorporate some of the same concepts and input assumptions, as discussed in more detail below.
  - o Transmission and Distribution Capacity Credits: a comparable methodology is in the 2025 IRP, but the specific values won't be reflected in UM 1893 until after acknowledges the 2025 IRP or otherwise adopts the assumptions for use in UM 1893.
  - o Generation Capacity Credits: the UM-1893 methodology uses the all-in fixed cost of a simple cycle combustion turbine. The 2025 IRP identifies the least-cost portfolio of resources needed to meet capacity requirements throughout the study horizon, based on the net cost of capacity (resource costs less the energy value the resource provides). The portfolio of resources includes varying combinations through time. The IRP modeling doesn't explicitly identify a net cost of capacity.
  - o Energy prices: the UM-1893 methodology uses monthly HLH/LLH market prices as the energy value. In the IRP, the system value and marginal energy value is calculated based on the energy efficiency volumes in each hour. Heating and cooling measures tend to provide greater energy savings under more strained conditions (colder in the winter or hotter in the summer), so the value of associated energy savings may be higher than a monthly average. The prices in the IRP also reflect the impacts of a given portfolio, as plentiful wind and solar resources can result in congestion resulting in energy values that are lower than the market price.
  - o Clean energy requirements: the most recent UM 1893 filing included higher avoided energy costs based on possible HB 2021 compliance requirements. The 2025 IRP will endogenously account for Oregon's HB 2021 compliance requirements and will include a combination of clean resources and new energy efficiency selections (offsets to load).

The 2025 IRP will select cost-effective energy efficiency bundles based on an optimization subject to all of the aspects described above. The cost-effective energy efficiency bundles may be modified in the CEP, based on additional analysis of possible compliance pathways.

**2. May 2 Public Input Meeting - Transmission modeling:**

a) Please explain with examples how the new 2025 IRP granularity adjustments to transmission modeling would be an improvement over the previous approach.

- o **Reply:** In the previous approach, transmission options did not receive a granularity adjustment, meaning the LT model's did not benefit from the data provided by the more granular ST model. For example, on a lower granularity time-block LT model basis, due to aggregation, a transmission option may appear to be valuable during periods where enabled resources cannot effectively make use of the transmission. Giving the LT model the benefit of the ST model's more granular hourly view will improve the selections the LT model is able to make. This change will also align with the methodology that is already in place for resources.

b) Is the ST import and export margin typically greater than the LT import and export margins?

- o **Reply:** Not necessarily, the margin could be lower indicating the transmission is not as valuable in the ST as the LT.

c) How is LMP forecasted for both short and long-term?

- o **Reply:** The Locational Marginal Price is calculated as the value of the final MW added to a topology location in the model.

* Required fields

d) How does the granularity adjustment impact interconnection transmission options that do not have flow to other bubbles? Is this kind of adjustment more in line with how flows occur in practice or is it only a modeling adjustment?
  - **Reply:** The exact mechanics of modeling granularity adjustments on interconnection options has not yet been finalized. As such, PacifiCorp is not yet able to determine what the impact may be. However, transmission options that are only for interconnection and do not provide incremental transmission capacity between topology bubbles are valued in the ST model based on optimization, just like any other resource.

**3. 2025 IRP recommendations based on analysis of 2023 IRP Update:**

**a)** PacifiCorp should continue to improve transparency and interactive improvements in the portfolio integration step to combine state policy portfolios with the system portfolio.
  - **Reply:** Thank you for your feedback. PacifiCorp has implemented reporting which compares the various portfolios to show differences in resource selections between the state specific and integrated portfolios. We welcome further feedback on these reporting enhancements.

**b)** PacifiCorp should report the steps taken to reduce the magnitude of reliability and granularity adjustments due to portfolio integration.
  - **Reply:** Thank you for your feedback. PacifiCorp has directly engages internal and Energy Exemplar subject matter experts on an ongoing basis, and has diligently pursued enhancements to its modeling to reduce the gap between LT and ST solutions. Regarding portfolio integration, the reliability and granularity are unique to each portfolio and impact initial resource selection. The integration leverages both LT and ST results from reliable portfolios and thus mitigates the impact of initial reliability or granularity adjustments as neither are considered in the system dispatch and valuation of individual resources in the ST model. It is the more granular ST model that is used to evaluate portfolio cost and risk.

**c)** PacifiCorp should improve the temporal granularity in the capacity expansion modeling to avoid the large number of modeling adjustments that incorporate sequential commitment and dispatch.
  - **Reply:** At this time, with the complexity of the PacifiCorp system and to comply with state requirements and stakeholder requests, it is not feasible to increase the level of granularity in a 20 year capacity expansion run. Other stakeholders have also advocated for this change. In order to immediately improve the granularity in a 20 year run there would have to be trade-offs that have been noted as undesirable by stakeholders, such as reducing resource options available to the model, reducing the granularity of the topology, fewer options for thermal plant selections and retirements, a non-endogenous selection of transmission, and relaxed tolerances for optimality and feasibility.

**d)** PacifiCorp should update the temporal configure of battery charging and discharging along with seasonal variability of renewables at the beginning of the modeling process to better capture their dynamics and possible combinations in capacity expansion analysis.
  - **Reply:** Thank you for your feedback. PacifiCorp is testing a variety of modeling improvements, including updates to battery properties, renewables shapes and updated transmission constraints which are likely to meet this goal. The objective is to allow the model the maximum practical range to optimally determine resource dispatch and storage usage following hourly system conditions, which may or may not confirm to a broader notion of seasonality in any given period.

**e)** PacifiCorp should layer in the fixed fuel costs at Jim Bridger and other coal plants within the PLEXOS model upfront rather than through post-processing workbooks.
  - **Reply:** Thank you for your feedback. All fuel costs related directly to actual operations of coal plants are included in PLEXOS modeling. Modeling of fixed costs related to mines or other external entities is not currently contemplated in PLEXOS.

**f)** PacifiCorp should provide workpapers showing how system portfolio resources are modified to support state policy decisions, as the Portfolio Optimization & Integration of state policy appears to be a new source of subjective judgement for resource selection.

- **Reply:** Please see the response to subpart a) above. The integration approach is designed to avoid subjectivity, in that resources are integrated on the basis of which portfolio include or exclude each resource. This information is used to determine which states are assumed to participate in each resource decision. The 2025 IRP will pursue great visibility into any adjustments that are not directly represented in the portfolio data.

**g)** PacifiCorp should provide more detail and a thorough explanation of its approach to brining the Bridger 3 and 4 CCUS project into service by 2029.

- **Reply:** Thank you for your feedback. Thermal unit options for the 2025 IRP are currently being developed for the August 14-15 public input meeting, and the timing for Bridger 3 and 4 CCUS is part of that development process.

**h)** PacifiCorp should provide a sensitivity that shows the impact of CCUS delays on the lifetime cost/benefit of the Bridger 3 and 4 units.

- **Reply:** Thank you for your feedback. Sensitivities for the 2025 IRP are currently being reviewed in the 2025 IRP public input meeting series.

**i)** PacifiCorp should engage stakeholders to develop more accurate hydrogen modeling assumptions.

- **Reply:** Updated assumptions are gathered for every IRP cycle. PacifiCorp appreciates feedback suggesting alternative data sources and considerations for hydrogen cost assumptions.

**j)** PacifiCorp should provide updated Natrium assumptions that reflect actual events and project milestones.

- **Reply:** Thank you for your feedback. Assumptions for the Natrium project to be used in the 2025 IRP are currently being developed. These assumptions will reflect the most current milestones available to PacifiCorp at the time of modeling the 2025 IRP.

**k)** PacifiCorp should address how asymmetric upside risk of market purchases during periods of peak demand is reflected in its market price projections. The Company should also address how declining market trading volumes are factored into the 2025 IRP model.

- **Reply:** Thank you for your feedback. PacifiCorp is exploring tightening limits on market purchases based on historical data related to peak demand days. Currently modeled market volumes are lower than historical market activity.

**l)** PacifiCorp should incorporate the requirements of the finalized 111 rules into PLEXOS.

- **Reply:** As discussed in the July Public Input Meeting, PacifiCorp is planning to use EPA rule 111d as part of the 2025 IRP analysis.

**m)** PacifiCorp should better consider the risks associated with emissions regulations across the west trending more toward tighter regulation to avoid over-exposing itself to regulatory risk.

- **Reply:** Risk assessment is a core function of PacifiCorp's approach to modeling and evaluation. Feedback suggesting additional data and considerations is welcome.

**n)** PacifiCorp should specifically detail their Oregon-specific resource procurement strategy and the impact of its current financial position, as discussed in the May 30, 2024 Public Meeting, on this procurement strategy.

- **Reply:** PacifiCorp's Oregon-specific procurement strategy is being developed in ongoing IRP and CEP processes. In the IRP, procurement objectives may be incorporated in the action plan.

**o)** Related to its levers for new resource additions in the 2023 CEP update, the Company should:

- Test multiple allocation strategies that are feasible within the context of MSP and for which the Company is willing to advocate.
- Ensure that each allocation strategy supports simultaneous compliance with all state-level policies to which PacifiCorp is subject.

- Be transparent about allocation assumptions and their implications, including the timing of any crucial allocation decisions to support policy compliance.
- Recognize the benefits of resources allocated to Oregon to the overall portfolio and reflect those cost savings in Oregon-allocated cost estimates.
  - **Reply:** PacifiCorp is currently participating in the process to determine the timing and nature of next steps for Oregon potential procurements and other levers as introduced in the April 2024 CEP Supplement. Multiple strategies are expected to be addressed, and portfolios are expected to be compliant with all state regulatory requirements.

**p)** Related to its lever for adding energy efficiency in the 2023 CEP update, the Company should:
- Consider additional energy efficiency within Oregon to contribute to achieving HB 2021 GHG targets, support Oregon communities, and reduce the need for generation, transmission, and distribution investments.
  - **Reply:** The company's integrated portfolio selected Oregon specific energy efficiency and demand response which was incrementally higher than the original portfolio in order to meet these needs.
- Adopt at least one Community Benefit Indicator (CBI) that reflects community benefits associated with energy efficiency selection in Oregon and recognizes the value of avoided transmission upgrades.
  - **Reply:** Avoided transmission benefits are currently a component of small scale resource planning.

**q)** Related to its levers for adjusting dispatch strategies for emitting resources in the 2023 CEP update, the Company should:
- Discuss how it intends to operationalize changes rather than just treating them as modeling assumptions.
  - **Reply:** PacifiCorp recognizes the need to describe details regarding the pros and cons of each of the levers, and what it means to operationalize particular assumptions. This analysis is planned for the 2025 CEP as the next step in the analysis introduced in the CEP Supplement.
- Compare the total systemwide GHG emissions under the alternative operational strategy to the total systemwide GHG emissions under a business-as-usual or economic dispatch operational strategy.
  - **Reply:** System emissions are expected to be a component of reporting for each portfolio used to evaluate the levers.

**r)** Related to its levers for changes to the DEQ Emissions Calculations in the 2023 CEP update, PacifiCorp should dialogue with DEQ over the coming months to determine if a change to the emissions methodology for qualifying facilities may be a worthwhile strategy to pursue.
- **Reply:** PacifiCorp is currently engaging with DEQ related to this topic.

s) PacifiCorp should provide analysis supporting the assumption that new natural gas plants are capable of converting to alternative fuels in the future. Further, are these plants modeled with non-emitting fuels in any of the analyses or is this just an assumption that impacts the economic life of gas plants?
- **Reply:** In conversations with various developers, PacifiCorp has been informed that this conversion is possible as of today. New natural gas plants are modeled as operating under natural gas throughout the life of the plant and the approximate modeled cost of alternative fuels and natural gas with a carbon tax cost adder are equivalent beginning in 2040.

t) Would PacifiCorp consider conducting an RFI prior to the 2025 IRP/CEP to better understand the market prices for new generation?
- **Reply:** This is not under consideration at this time.

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* Required fields

**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.

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**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.

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Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com

Thank you for participating.

* Required fields

# PacifiCorp - Stakeholder Feedback Form (018)

## Integrated Resource Plan

PacifiCorp (the Company) requests that stakeholders provide feedback to the Company upon the conclusion of each public input meeting and/or stakeholder conference call, as scheduled. PacifiCorp values the input of its active and engaged stakeholder group, and stakeholder feedback is critical to the IRP public input process. PacifiCorp requests that stakeholders provide comments using this form, which will allow the Company to more easily review and summarize comments by topic and to readily identify specific recommendations, if any, being provided. Information collected will be used to better inform issues included in the IRP, including, but not limited to the process, assumptions, and analysis. In order to maintain open communication and provide the broader Stakeholder community with useful information, the Company will post appropriate feedback on the IRP website based on your selection below.

Date of Submittal: 2024-07-19


*Name: William Achi

Title:

*E-mail: william.achi@wyo.gov

Phone: (478) 456 - 1166

*Organization: Wyoming Office of Consumer Advocate

Address: 2515 Warren Ave, Suite 304

City: Cheyenne  State: WY  Zip: 82002


Public Meeting Date comments address: ☐ Check here if related to specific meeting

List additional organization attendees at cited meeting:

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.

wildfire risk, regional and interregional transmission

☒ Check here if you want your Stakeholder feedback and accompanying materials posted to the IRP website.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.

Given the wildfire costs that PacifiCorp has experienced, how does the Company plan to address the wildfire risk associated with regional and interregional transmission projects and assets, especially those located within high risk zones/high fire consequence zones? Does the IRP model consider wildfire mitigation techniques (e.g. undergrounding, covered conductors, EFR reclosers, etc.) and their associated costs when resource selections include regional and interregional transmission? If it does, how does the model determine when and which wildfire mitigation techniques are needed? Additionally, does the model consider the liability costs and legal liability costs related to transmission related wildfire risk?

**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.

**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.

If PacifiCorp does not currently include wildfire risk related costs in the IRP model, it should do so when resource selections include regional and interregional transmission.

Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com

Thank you for participating.

* Required fields

**PacifiCorp Response (8/12/2024):**

Thank you for your feedback and engagement in the Integrated Resource Planning process.
PacifiCorp does not currently include wildfire-related costs distinctly in its modelling for the Integrated Resource Plan (IRP). Wildfire-related costs are assumed in the social cost of greenhouse gas price-policy scenario. Transmission-related costs for mitigation techniques are incorporated in IRP modeling to the extent they are a component of the costs assumed for specific transmission options. Regional and interregional transmission plans are developed through the NorthernGrid regional planning process. Any transmission-related costs derived from wildfire mitigation considerations in the NorthernGrid regional planning process would be reflected in the cost estimates assumed for specific transmission options. Transmission-related wildfire mitigation strategies are being actively considered for both existing and new transmission. Any transmission-related costs derived from wildfire mitigation considerations would be reflected in the cost estimates for transmission and distribution deferral values used in the IRP.

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# PacifiCorp - Stakeholder Feedback Form (019)

## Integrated Resource Plan

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Date of Submittal 2024-07-19


*Name: William Achi

Title:

*E-mail: william.achi@wyo.gov

Phone: (307) 777 - 5705

*Organization: Wyoming Office of Consumer Advocate

Address: 2515 Warren Ave, Suite 304

City: Cheyenne State: WY Zip: 82002


Public Meeting Date comments address: 07-18-2024 ☒ Check here if related to specific meeting

List additional organization attendees at cited meeting:

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.
Chehalis natural gas plant, Washing Climate Commitment Act cap-and-invest program, modeling scenarios

☒ Check here if you want your Stakeholder feedback and accompanying materials posted to the IRP website.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.
At the July 18, 2024 IRP meeting PacifiCorp stated that for all scenarios that will be modeled, emissions from the Chehalis natural gas plant will incur the forecasted cost of allowances under the cap-and-invest program established in the Climate Commitment Act (CCA) passed by the Washington Legislature in 2021. Given that several states have already rejected the inclusion of these costs in rates, and that PacifiCorp has challenged these costs in court, we find it concerning that the Company\u0019s modeling strategy does not include any scenarios in which Chehalis is modeled without the cost and dispatch impacts of the cap-and-invest program.

**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.

**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.
We would recommend the Company provide resource selections modeled without the cost and dispatch impacts of the WA CCA cap-and-invest program on the Chehalis natural gas plant.

PacifiCorp Response (8/1/2024):

Thank you for your recommendation. We have not modeled Chehalis without considering the cost and dispatch impacts of the WA CCA cap-and-invest program. Notwithstanding that certain commissions have declined to allow the company to recover these cost, the company continues to incur these costs. The company is monitoring ballot measures that could

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appeal the CCA. Chehalis provides capacity to the system and demonstrated cost-effectiveness in the 2023 IRP.

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Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com

Thank you for participating.

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# **PacifiCorp - Stakeholder Feedback Form** (021)

Integrated Resource Plan

PacifiCorp (the Company) requests that stakeholders provide feedback to the Company upon the conclusion of each public input meeting and/or stakeholder conference call, as scheduled. PacifiCorp values the input of its active and engaged stakeholder group, and stakeholder feedback is critical to the IRP public input process. PacifiCorp requests that stakeholders provide comments using this form, which will allow the Company to more easily review and summarize comments by topic and to readily identify specific recommendations, if any, being provided. Information collected will be used to better inform issues included in the IRP, including, but not limited to the process, assumptions, and analysis. In order to maintain open communication and provide the broader Stakeholder community with useful information, the Company will post appropriate feedback on the IRP website based on your selection below.

Date of Submittal 2024-07-03

*Name: Jim Himelic Title:
*E-mail: jhimelic@firstprinciples.run Phone: 5209791375
*Organization: Renewable Northwest
Address:
City: State: Zip:
Public Meeting Date comments address: ☐ Check here if related to specific meeting
List additional organization attendees at cited meeting:

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.
Configuration details for Plexos Modeling Exercises

☒ Check here if you want your Stakeholder feedback and accompanying materials posted to the IRP website.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.

While Renewable Northwest (RNW) is still awaiting a response from PacifiCorp regarding our original Stakeholder feedback form submitted on May 2nd, which inquired about the specific PLEXOS LT settings PacifiCorp is employing, we would like to add the following PLEXOS-related questions to that request:

- **PLEXOS Production Settings:** Please provide a copy of the production settings used for all final PLEXOS runs. If separate settings were used for LT and MT-ST runs, please provide each set of settings.
- **PLEXOS Performance Settings:** Please provide a copy of the performance settings used for all final PLEXOS runs. If separate settings were used for LT and MT-ST runs, please provide each set of settings.
- **PLEXOS Horizon Settings:** Please provide a copy of the horizon settings used for all final PLEXOS MT-ST runs.
    - Has PacifiCorp explored the impacts on modeling results and run times when using Typical Week Per Month reduced chronology for the ST Schedule?
    - Note: While RNW does not encourage this setting for reliability-focused ST runs, the mode can be effective in reducing run time requirements when performing economic-focused simulations across an extended planning horizon.
- **PLEXOS MT Settings:** Please provide a copy of the performance settings used for the MT phase of PLEXOS simulations.
    - For the decomposition of the MT targets, does PacifiCorp implement this as a quantity-based target (i.e., a hard constraint) or as a price-based target (i.e., a soft constraint)?
    - 
- **Other:**

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- o Please discuss to what extent PacifiCorp has explored the various options provided by Energy Exemplar to PLEXOS users for configuring PLEXOS LT runs, particularly in balancing the tradeoffs between chronology resolution and run times. Specifically, please address whether PacifiCorp has considered options such as:
    - ▪ Mixed Chronology
    - ▪ Rolling Horizons
    - ▪ Multistep Optimization with overlapping steps
    - ▪ Integerization horizon for expansion decisions optimality
- o Has PacifiCorp explored using the Projected Assessment of System Adequacy (PASA) modeling stage to assist with a first pass reliability run or creating planned maintenance schedules for their thermal generation fleet?
- o Related to performance settings, has PacifiCorp explored using the Gurobi Tuner software program provided by Energy Exemplar?
    - ▪ This tool optimizes the settings for the Gurobi solver specific to each model by using an MPS file description of the modeled portfolio.
    - ▪ The program identifies the optimal set of solver settings, including undocumented parameters beyond those available through the PLEXOS interface, for a user-specified MIP gap.
- o Has PacifiCorp explored using the [Load Subtracter] property under the Generator class?
    - ▪ This parameter allows the chronology algorithm in PLEXOS LT to be applied to the net load profile (i.e., gross load netted out with zero variable costs generation) rather than the gross load profile.
    - ▪ This enables a more efficient allocation of the fixed number of blocks accessible to the optimizer to the critical periods in the planning horizon.
- o Does PacifiCorp perform any backcasting validation runs on their PLEXOS model regularly?

Please note that RNW is requesting this information to assist PacifiCorp in addressing their modeling needs. RNW recognizes the complexity associated with effective capacity expansion, resource adequacy, and production cost modeling. Given the size and complexity of PacifiCorp’s portfolio, these tasks are even more challenging. In that spirit, RNW has PLEXOS modeling expertise under retainer and offers this support in the spirit of collaboration and continuous progress for the IRP process. RNW is also supportive of PacifiCorp hosting a technical modeling workshop to discuss these items, along with other related modeling topics, if that would be most effective for all stakeholders.

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**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.

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**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.

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Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com

Thank you for participating.

**PacifiCorp Response (8/XX/2024):**

* Required fields

Thank you for your feedback and engagement in the Integrated Resource Planning process. Please see the following tables, which display the Plexos settings used in the 2023 IRP Update:

**PLEXOS Production Settings:**

| | LT Models | MT/ST Models |
|---|---|---|
| Category | - | - |
| Dispatch by Power Station (Yes/No) | Yes | Yes |
| Power Station Aggregation Mode | None | None |
| Unit Commitment Optimality | Linear | Linear |
| Rounding Up Threshold | 0.5 | 0.5 |
| Rounded Relaxation Commitment Model | Central | Central |
| Rounded Relaxation Tuning (Yes/No) | No | No |
| Rounded Relaxation Start Threshold | 0.25 | 0.25 |
| Rounded Relaxation End Threshold | 0.75 | 0.75 |
| Rounded Relaxation Threshold Increment | 0.05 | 0.05 |
| DP Capacity Factor Threshold (%) | 20 | 20 |
| DP Capacity Factor Error Threshold (%) | 20 | 20 |
| Capacity Factor Constraint Basis | Installed Capacity | Installed Capacity |
| Forced Outage Relaxes Min Down Time (Yes/No) | No | No |
| Gas Demand Resolution | Interval | Interval |
| Heat Rate Detail | Detailed | Detailed |
| Unit Commitment Heat Rate Detail (Yes/No) | Yes | Yes |
| Integers in Look-ahead | Never | Never |
| Cooling States Enabled (Yes/No) | No | Yes |
| Run Up and Down Enabled (Yes/No) | No | Yes |
| Transitions Enabled (Yes/No) | Yes | Yes |
| Start Cost Method | Optimize | Optimize |
| Start and Stop Enabled (Yes/No) | No | Yes |
| Ramping Constraints Enabled (Yes/No) | Yes | Yes |
| Pump and Generate (Yes/No) | No | Yes |
| Increment and Decrement (Yes/No) | Yes | Yes |
| Fuel Use Function Precision | 0 | 0 |
| Max Heat Rate Tranches | 5 | 3 |
| Min Heat Rate Tranche Size | 0 | 0 |
| Heat Rate Error Method | Warn Adjust Report Adjusted | Warn Adjust Report Adjusted |
| Formulate Upfront (Yes/No) | Yes | Yes |
| Formulate Ramp Upfront (Yes/No) | Yes | Yes |
| Warm Up Process Enabled (Yes/No) | Yes | Yes |

* Required fields

**PLEXOS Performance Settings:**

| | LT Models | MT/ST Models |
|---|---|---|
| Category | - | - |
| SOLVER | Gurobi | Gurobi |
| Small LP Optimizer | Auto | Auto |
| Small LP Nonzero Count | 250000 | 250000 |
| Cold Start Optimizer 1 | Barrier Homogeneous | Auto |
| Cold Start Optimizer 2 | None | None |
| Cold Start Optimizer 3 | None | None |
| Hot Start Optimizer 1 | Barrier Homogeneous | Auto |
| Hot Start Optimizer 2 | None | None |
| Hot Start Optimizer 3 | None | None |
| Concurrent Mode | Deterministic | Deterministic |
| Presolve (Yes/No) | Yes | Yes |
| Scaling (Yes/No) | Yes | Yes |
| Crossover (Yes/No) | Yes | Yes |
| Feasibility Tolerance | 0 | 0 |
| Optimality Tolerance | 0 | 0 |
| Objective Scalar | 1 | 1 |
| Objective Tolerance | 0 | 0 |
| Maximum Threads | -1 | -1 |
| MIP Root Optimizer | Auto | Dual Simplex |
| MIP Node Optimizer | Auto | Dual Simplex |
| MIP Relative Gap | 0.0002 | 0.0002 |
| MIP Improve Start Gap | 0 | 0 |
| MIP Absolute Gap | 0 | 0 |
| MIP Max Relative Gap | 0 | 0 |
| MIP Max Absolute Gap | 0 | 0 |
| MIP Max Time (s) | 7200 | 3600 |
| MIP Max Relaxation Repair Time (s) | -1 | -1 |
| MIP Maximum Threads | -1 | 12 |
| MIP Start Solution | Within Step | Within Step |
| MIP Focus | Balanced | Balanced |
| Carry over MIP Time (Yes/No) | Yes | No |
| MIP Max Time with Carry over (s) | -1 | -1 |
| MIP Hard Stop (s) | -1 | -1 |
| MIP Interrupt (Yes/No) | No | No |
| Hint Mode | Start | Start |
| Monitoring Periodic Clearing | 0 | 0 |
| Monitoring Maximum Threads | -1 | -1 |
| Maximum Monitored MIP Iterations | -1 | -1 |
| Maximum Parallel Tasks | -1 | -1 |
| Feasibility Repair Failure | Continue | Continue |

**PLEXOS Horizon Settings:**

* Required fields

| | LT Models | MT/ST Models |
|---|---|---|
| Category | - | - |
| Periods per Day | 24 | 24 |
| Compression Factor | 1 | 1 |
| Date From | 1/1/2023 | 1/1/2023 |
| Step Type | Year | Year |
| Step Count | 20 | 20 |
| Look-ahead Count | 0 | 0 |
| Day Beginning | 0 | 0 |
| Week Beginning | 0 | 0 |
| Year Ending | 0 | 0 |
| Chronology | Full | Full |
| Chrono Date From | 1/1/2023 | 1/1/2023 |
| Chrono Period From | 1 | 1 |
| Chrono Period To | 24 | 24 |
| Chrono Step Type | Day | Week |
| Chrono At a Time | 1 | 1 |
| Chrono Step Count | 7305 | 1043 |
| Look-ahead Indicator (Yes/No) | No | Yes |
| Look-ahead Type | Day(s) | Day(s) |
| Look-ahead At a Time | 2 | 3 |
| Look-ahead Periods per Day | 12 | 12 |

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**PLEXOS MT Settings:** Performance settings.
There do not appear to be any "MT Schedule" settings in PLEXOS 9.2, that relate to "…the decomposition of the MT targets**…"** as described in this question.

MT targets are generally set based on the specific property and associated spanning condition. PacifiCorp is taking steps to change the model properties in order to bypass the MT phase where appropriate when running an ST deterministic model run. For example: we have specifically defined the "Max Capacity Factor Week" for DSM-Demand Response. Rather than attempting to optimize demand response dispatch based in the MT phase, a portion of the overall demand response capability is allocated to each week in the relevant season, with more events in periods with greater risk or need. This emulates actual practice, where, outside of an emergency where a program would immediately be used to the maximum extent allowed, a portion of the events will be reserved in case they are needed in the remainder of the season.

**Other:**

- **Configuring PLEXOS LT runs**
  - PacifiCorp has explored and continues to explore all model setups/options on an ongoing basis in an attempt to improve modeling performance and in order to achieve LT portfolio results that are more reliable and consistent with the results we see in the ST phase of PLEXOS modeling. We do not see a setting for "Mixed Chronology", however, we currently use the "Partial" chronology setting in our LT model runs.

    Fitted and sampled have been tested multiple times. We see the best results using the combination of partial and our custom slicing combined with 7 Blocks/Month. Rolling Horizons had been tested in the past but this setup was not functioning; however Energy Exemplar has indicated this functionality has been fixed and should work. We are testing this setup currently for the 2025 IRP, but it reports faulty infeasibilities. Tests using the integerization horizon for expansion decisions has not resulted in meaningful run-time improvements.

    PacifiCorp has found that focusing on specific unit types being modeled as linear/integer rreults in more significant run-time improvements. For example, only existing plant retirements and certain transmission upgrades may need to be considered on an integer basis.

  - PacifiCorp has not explored the use of the PASA modeling stage.

  - PacifiCorp has not explored using the "Gurobi Tuner" software, but the Company is interested to learn more about this. As stated, we are always looking to improve our model setups and assumptions.

  - **Load Subtracter:** PacifiCorp had tested using a load subtractor setup to help the model with Blocking, but it did not appear to provide a useful improvement. Because load subtractor is tied to specific volumes identified prior to running the LT, it does not incorporate the outcomes of the portfolio selection. This setup would not work with our current LT setup that uses custom slicing which accounts for our wind and solar profiles.

  - PacifiCorp has not attempted to perform any type of backcasting validation within PLEXOS. PacifiCorp has been reviewing historical load, market price, and generator availability data to see whether the forecasting and modeling of these inputs can be improved to better reflect both the expected variation in these inputs experienced on an actual basis and the correlation among these inputs. In actual operations, PacifiCorp balances much of its requirements using market products transacted on a forward and day-ahead basis. PLEXOS currently only uses hourly balancing, so it does not have forward and day-ahead market products, nor does it capture all of the impacts of hedging requirements and forecast error. For the 2025 IRP, PacifiCorp is working to incorporate the forward showing requirements associated with the Western Resource Adequacy Program (WRAP), and those requirements are likely to impact how forward market transactions are used in practice. Similarly, PacifiCorp expects to begin operating within the CAISO's Enhanced Day-Ahead Market (EDAM) starting in 2026, which may also impact operations. These two developments are likely to improve the alignment between actual operations and PLEXOS and will reduce the relevance of recent actual results. PacifiCorp remains open to specific suggestions that might improve the performance and accuracy of our modeling.

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# PacifiCorp - Stakeholder Feedback Form (022)

## Integrated Resource Plan

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Date of Submittal 2024-07-27


*Name: Christopher Thomas Title:

*E-mail: christopher.thomas@slc.gov Phone: (385) 228 - 6873

*Organization: Salt Lake City Corp

Address: 451 S. State Street

City: Salt Lake City State: UT Zip: 84111


Public Meeting Date comments address: 07-17-2024 ☒ Check here if related to specific meeting

List additional organization attendees at cited meeting:

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.

Numbered slide 51 titled \u001CVariants\u001D

☒ Check here if you want your Stakeholder feedback and accompanying materials posted to the IRP website.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.

Please include an additional variant, \u001Cnear-term customer choice energy\u001D that would allow for the selection of energy resources by the PLEXOS model for operation in 2026 and 2027 in the following amounts: 493 MW of solar, 126 MW of wind, and 32 MW of geothermal. These numbers reflect the total summer megawatts (MW) in the PacifiCorp interconnection queues that have completed Facilities studies with a requested commercial operation date prior to December 31, 2026 for each of these energy resource types. The rationale for including this variant is that PacifiCorp\u0019s core cases do not allow for the selection of wind or solar resources before calendar year 2028, reflecting a constraint that represents the regulatory timeline of initiating an all-source RFP and completing contracting and project construction. However, there are programs and tariffs that could allow for large customers or groups of customers to acquire energy from the projects in PacifiCorp\u0019s interconnection queues before 2028. Given that, it would be prudent to use one IRP model variant to examine whether limited amounts of new energy resource acquisition prior to 2028 would be cost effective from the perspective of the PacifiCorp system as a whole. The 2023 IRP update preferred portfolio found that near-term resource acquisition would be cost effective, to the tune of 654 MW of solar or solar + storage in 2027 and 79 MW of wind in 2027.

**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.

**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.

* Required fields

```
Please ensure that the \u001Cnear-term customer choice energy\u001D variant will allow
for the selection of solar and wind resources in the amounts listed above without co-
located storage.
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Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com

Thank you for participating.

**PacifiCorp Response (7/XX/2024):**

Thank you for your participation and engagement in the Integrated Resource Planning process.

PacifiCorp is actively considering projects that have a commercial operation date before 1/1/2028 and does not foreclose the opportunity for such projects. The Integrated Resource Plan (IRP) is based on proxy resource costs and related assumptions that are generic and intended to be broadly applicable. Thus, the IRP has typically not allowed resources to be selected within the initial few years of the model run even if PacifiCorp might still be able to pursue projects that could enter commercial operation during those initial few years.

The Company is currently considering all requests for additional sensitivity and variant studies to be completed in the 2025 IRP. Possible options will be discussed in the August 14-15 and September 25-26 Public Input Meetings.

* Required fields

# PacifiCorp - Stakeholder Feedback Form (023)
## Integrated Resource Plan

PacifiCorp (the Company) requests that stakeholders provide feedback to the Company upon the conclusion of each public input meeting and/or stakeholder conference call, as scheduled. PacifiCorp values the input of its active and engaged stakeholder group, and stakeholder feedback is critical to the IRP public input process. PacifiCorp requests that stakeholders provide comments using this form, which will allow the Company to more easily review and summarize comments by topic and to readily identify specific recommendations, if any, being provided. Information collected will be used to better inform issues included in the IRP, including, but not limited to the process, assumptions, and analysis. In order to maintain open communication and provide the broader Stakeholder community with useful information, the Company will post appropriate feedback on the IRP website based on your selection below.

Date of Submittal 2024-08-09

*Name: Jon Martindill Title:

*E-mail: jon@npenergyca.com Phone:

*Organization: NP Energy LLC

Address:

City: State: Zip:

Public Meeting Date comments address: 06-27-2024 ☐ Check here if related to specific meeting

List additional organization attendees at cited meeting: Nick Pappas, Max Greene, James Himelic

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.
Non-Emitting Peakers - Hydrogen fuel availability

☒ Check here if you want your Stakeholder feedback and accompanying materials posted to the IRP website.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.
RNW seeks additional analysis and due diligence from PacifiCorp regarding its hydrogen cost and availability assumptions. Non-emitting peakers play a large role in PacifiCorp\u0019s 2023 IRP, and an even greater role in the 2023 IRP Update. The 2023 IRP includes 1,240 MW of non-emitting peakers by 2036. In the 2023 IRP Update, all gas peakers are assumed to be capable of transitioning to hydrogen, an assumption that extends the modeled operational life of all natural gas resources, culminating in 5,000 MW of non-emitting peakers in 2041. The growth of non-emitting and hydrogen-capable peakers seems to be driven in part by Oregon compliance, but more broadly due to coal retirements.  In comments submitted on June 14, 2024, RNW identified four gaps in PacifCorp\u0019s planning. 1) Additional energy production requirements necessary to produce green hydrogen; 2) Water consumption to produce green hydrogen; 3) Cost and viability of infrastructure to transport and store hydrogen; and 4) Impact, monitoring, and mitigation necessary to address hydrogen leakage In the June 27 Public Input Meeting, PacifiCorp acknowledged many of the drawbacks and challenges to combusting green hydrogen to generate power, including its poor round-trip efficiency, need for significant new and expensive infrastructure, and leakage. Further, PacifiCorp acknowledged that there is \u001Ca lot of work that would need to be done to create a hydrogen economy at a scale for utility power generation\u001D including a \u001Ctremendous amount of infrastructure\u001D. In this same session, PacifiCorp clarifies that the 2023 IRP update does not have specific plans to run the hydrogen-capable peakers with 100% hydrogen, and that these are included as a \u001Chedge against the possibility that they will need to run 100% hydrogen at a point in the future. \u001D  RNW seeks additional clarification from PacifiCorp on how it would address these uncertainties and ensure that, to the extent hydrogen peakers are a necessary element of a compliant portfolio, it will ensure that these resources are both capable of utilizing and supplied by green hydrogen to the designated state or federal standard.

* Required fields

**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.
Meeting cited: https://www.youtube.com/watch?v=ifpGWde0nBI&t=2106s

**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.
As long as PacifiCorp\u0019s IRP models operate on optimistic assumptions about hydrogen availability and cost, RNW asks for specific planning on how PacifiCorp plans to acquire, store, and potentially produce the of hydrogen necessary to generate power. Specifically, RNW recommends that PacifiCorp: 1) Incorporate the green hydrogen energy requirement as an incremental portfolio requirement for renewable energy production, enabling PLEXOS LT to increase clean energy production to meet electrolysis demand. 2) Perform a viability and cost assessment of electrolyzer sites that minimize cost of delivered green hydrogen to planned non-emitting peakers. These sites must meet grid connectivity requirements and water availability requirements. 3) Perform a viability and cost assessment of hydrogen storage siting and sizing to determine the capital and operational expenses associated with relying on hydrogen fuel for power generation. 4) Perform a viability and cost assessment of hydrogen transportation infrastructure. 5) Include leak monitoring and leak mitigation into hydrogen infrastructure planning, and include global warming impacts of hydrogen leakage into emissions assessments.

Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com

Thank you for participating.

**PacifiCorp Response (9/10/2024):**

Thank you for your feedback. With regard to your recommendation 1, for an incremental portfolio requirement, the company believes that proposed analysis of Oregon and Washington compliance requirements will achieve comparable results. At the August 14-15, 2024 public input meeting, the company presented both tank and cavern storage options for hydrogen, which in combination with electrolysis could allow for increased clean energy production. The company is still finalizing this modeling for the 2025 Integrated Resource Plan (IRP), and does not intend to conduct site-specific or project-specific evaluations as suggested in recommendations 2-5, as those are outside the scope of the IRP, which does not evaluate specific projects. PacifiCorp appreciates the expertise offered by RNW and believes these recommendations may be helpful in developing specifications and requirements for non-emitting peaking resources for inclusion in a Request for Proposals (RFP) following the 2025 IRP.

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# PacifiCorp - Stakeholder Feedback Form (024)

## Integrated Resource Plan

PacifiCorp (the Company) requests that stakeholders provide feedback to the Company upon the conclusion of each public input meeting and/or stakeholder conference call, as scheduled. PacifiCorp values the input of its active and engaged stakeholder group, and stakeholder feedback is critical to the IRP public input process. PacifiCorp requests that stakeholders provide comments using this form, which will allow the Company to more easily review and summarize comments by topic and to readily identify specific recommendations, if any, being provided. Information collected will be used to better inform issues included in the IRP, including, but not limited to the process, assumptions, and analysis. In order to maintain open communication and provide the broader Stakeholder community with useful information, the Company will post appropriate feedback on the IRP website based on your selection below.

Date of Submittal 2024-08-09


*Name: Jon Martindill
Title:
*E-mail: jon@npenergyca.com
Phone:
*Organization: NP Energy LLC
Address:
City: State: Zip:


Public Meeting Date comments address: 07-18-2024 ☐ Check here if related to specific meeting

List additional organization attendees at cited meeting: Nick Pappas, Max Greene, James Himelic

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.
Candidate Resource Costs

☒ Check here if you want your Stakeholder feedback and accompanying materials posted to the IRP website.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.
RNW seeks additional information from PacifiCorp regarding its assumptions and methods around resource costs. In comments submitted on June 14, RNW questioned PacifiCorp\u0019s unsubstantiated escalators for renewable energy resources used in the 2023 IRP and 2023 IRP Update. In those comments, RNW demonstrated that third-party sources of information, including NREL ATB 2024, did not support PacifiCorp\u0019s assumptions about renewable resource costs and their change over time. In the July 18 Public Input Meeting, PacifiCorp stated that they are basing cost estimates for proxy resources on NREL ATB 2024, but that there are additional costs that PacifiCorp adds to the ATB estimate to more accurately reflect the true cost. In order to meaningfully engage with the resource costs, a critical input to any planning exercise, PacifiCorp must provide additional information and substantiation on this adjustment step than has been made available previously. Therefore, RNW asks that this adjustment step be made as transparently as possible.

**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.

**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.
Please provide specific information on the following questions: 1) What specific costs are added in this adjustment step, and what information sources are used to estimate these costs? 2) How do cost adjustments vary by resource? 3) How do cost adjustments vary over time? 4) How will this cost adjustment step be transparent to stakeholders? 5) Will

* Required fields

PacifiCorp share the specific cost adjustments applied to each resource and the rationale behind each adjustment?

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Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com

**PacifiCorp Response:**

1) Regarding capital costs presented in the Supply-side Resource table (column heading "CAPEX"), the National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB) provides overnight capital cost (OCC) in 2022 dollars for the year of commercial operation (COD year). The ATB's OCC for the appropriate soonest COD year is escalated to from 2022 dollars to 2024 dollars. Then the following costs are added:
    - Allowance For Funds Used During Construction (AFUDC): this reflects the cost of funds used prior to commercial operation and incorporates PacifiCorp's confidential financial costs in the calculation. This is used instead of the ATB's Finance Factor.
    - Capital surcharge: administrative and general costs, which cannot be charged directly to a capital project, in accordance with the Federal Energy Regulatory Commission (FERC) and generally accepted accounting principles (GAAP).
    - Property tax: 1.2%

2) The CAPEX described in response to question 1 varies by location and tax incentive rules. Locational cost factors were obtained from the United States Energy Information Agency report: "Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies, January 2024." For resources that do not have a cost forecast, standard inflation is applied. Additionally, instead of using the ATB's interconnection costs, the Company's PLEXOS modeling reflects location-specific interconnection cost estimates from throughout PacifiCorp's transmission system.

3) CAPEX costs vary over time according to the ATB's cost forecasts, adjusted for inflation.

4) The cost adjustments indicated above were discussed at the July and August public input meetings for the 2025 IRP (Public Input Process (pacificorp.com)). Additional information provided in this response is publicly available along with the 2025 IRP Supply-side Resource table Integrated Resource Plan (pacificorp.com).

5) The overarching rationale is to provide information that is more consistent with PacifiCorp's expected costs in its operating areas than that represented by the nationwide average costs provided in the ATB. The rationale behind each individual resource adjustment does not vary except as described above.

Thank you for participating.

* Required fields

# PacifiCorp - Stakeholder Feedback Form (025)

## Integrated Resource Plan

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Date of Submittal


*Name: Jon Martindill    Title:

*E-mail: jon@npenergyca.com    Phone:

*Organization: NP Energy LLC

Address:

City:    State:    Zip:


Public Meeting Date comments address: 07-18-2024    ☐ Check here if related to specific meeting

List additional organization attendees at cited meeting: Nick Pappas, Max Greene, James Himelic

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.
Carbon Capture and Storage

☒ Check here if you want your Stakeholder feedback and accompanying materials posted to the IRP website.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.
RNW seeks additional information and due diligence from PacifiCorp regarding its application of carbon capture and storage (CCS) in its 2023 IRP Update. The 2023 IRP Update extends and expands reliance on existing fossil infrastructure, including significant increases in CCS at PacifiCorp\u0019s coal units. RNW seeks additional due diligence on the compliance risk and economic risk of relying on CCS to prolong coal plant operations and reduce emissions. There are many technical barriers to overcome for effective CCS, as well as a variety of lifecycle emissions and local pollutants that make continued coal operations inherently risky. In addition, the economics of coal plan operations remain sensitive to a variety of factors.

**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.

**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.
Please provide specific information on the following questions: 1) What is the plan for the captured carbon? Is there a specific storage or utilization plan? Are the costs of storage and/or utilization included in the economic analysis? 2) Has PacifiCorp performed a sensitivity analysis on the economics of CCS? To what extent is this selection sensitive to CCS efficiency, coal fuel costs, and carbon storage/utilization costs? 3) What data source(s) informed NVE\u0019s estimate of $32.71/kw-year for fixed costs to operate a 330 MW CCUS retrofit? NREL ATB 2024 estimates a range of $148-$161/kw-year for a similar retrofit installed in 2028. 4) Are air quality impacts from coal trans included in your analysis?

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Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com

**PacifiCorp Response (8/28/2024):**

PacifiCorp's 2023 IRP Update identified the Jim Bridger units 3 and 4 carbon capture project as a potential economic benefit to customers. This analysis relied upon high-level proxy costs in the economic modeling which needs to be validated by a front-end engineering design (FEED) study before advancing a carbon capture project. The Company is pursuing a FEED study that will evaluate the capture, transport and storage of $CO_2$ from Jim Bridger units 3 and 4.

1. The FEED study will evaluate an option for transport and storage of the $CO_2$. Cost for transportation and storage are accounted for in the economic modeling.

2. The company used a single set of CCUS cost inputs and is aware that many of the factors used to determine those cost inputs are highly uncertain. We have not yet conducted a specific analysis for the breakeven point for coal fuel cost, efficiency, etc., due to the significant amount of uncertainty surrounding these factors. The FEED study identified above is expected to provide better information on possible outcomes so that such analysis could be conducted in the future.

3. The NETL 2023 Report – "Eliminating the Derate of Carbon Capture Retrofits" includes cost items that PacifiCorp does not take into account in fixed operations and maintenance cost. However, those line items are being included in the total cost of the project.

4. The company has three plants where coal is received via rail: Bridger, Dave Johnston and Hayden. The company operates Bridger and Dave Johnston while Hayden is operated by Xcel Energy. For plants operated by the company, dust suppression is applied to all the trains where required (those loaded from Powder River Basin origins). This would include all coal destined for Dave Johnston and some of the coal destined for Jim Bridger. That dust "topper" is purchased on a $/ton rate and applied at the mine as the coal is loaded in the cars. IRP modeling is based on the delivered cost of coal, and includes both rail and dust suppression, as applicable. The company doesn't have direct control of the Hayden trains, so it does not have details for that plant, though it expects practices are similar.

Thank you for participating.

* Required fields

# PacifiCorp - Stakeholder Feedback Form (026)
Integrated Resource Plan

PacifiCorp (the Company) requests that stakeholders provide feedback to the Company upon the conclusion of each public input meeting and/or stakeholder conference call, as scheduled. PacifiCorp values the input of its active and engaged stakeholder group, and stakeholder feedback is critical to the IRP public input process. PacifiCorp requests that stakeholders provide comments using this form, which will allow the Company to more easily review and summarize comments by topic and to readily identify specific recommendations, if any, being provided. Information collected will be used to better inform issues included in the IRP, including, but not limited to the process, assumptions, and analysis. In order to maintain open communication and provide the broader Stakeholder community with useful information, the Company will post appropriate feedback on the IRP website based on your selection below.

Date of Submittal 2024-08-09


*Name: Kate Bowman  Title:

*E-mail: kbowman@votesolar.org  Phone: (801) 872 - 3234

*Organization: Vote Solar

Address:

City:  State:  Zip:


Public Meeting Date comments address:  ☐ Check here if related to specific meeting

List additional organization attendees at cited meeting:

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.
Distributed Generation Study, Sensitivities

☒ Check here if you want your Stakeholder feedback and accompanying materials posted to the IRP website.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.
Questions: Does the distributed generation study include any locational forecasting of DER adoption more specific than state level? Does the IRP evaluate any interactive effects between distributed energy resource adoption and other customer-sited technologies? For example, interactive effects between high DER adoption and high electrification, or high adoption of EVs? In the June 26 - 27 presentation, slide 42 states \u001CNet-billing states tied to avoided cost forecast from IRP.\u001D In this context, does avoided cost refer to PURPA rates for qualifying facilities? Or something else? How are forecasts for future avoided costs developed?  In the June 26 - 27 presentation, slide 42 states the value of backup power is \u001CIncluded in customer benefits of PV + Battery technology.\u001D How specifically is the value of backup power used as an input to the \u001Chigh\u001D forecast? Why does PacifiCorp believe that it is appropriate to assume no value for backup power in the \u001Cbase\u001D case as well as the \u001Clow\u001D case? What assumptions does the distributed generation study include about how customer batteries are dispatched? For example, how many hours, how many days a year, or which hours? Does the presence of solar/storage systems in the adoption forecasts result in a different load profile than solar alone? Does the load forecast account for the load effects of a customer dispatching their battery, for example in response to a time of use rate? Have PacifiCorp\u0019s past RFPs allowed for distributed generation resources to bid into the RFP? For example, could a virtual power plant bid into an RFP as a potential resource? Recommendations:  Increase the granularity of distributed energy resource forecasting and include locational forecasts of distributed energy resource adoption. Locational forecasting of DER adoption is necessary to capture the full value of DER resource additions and supports efficient investment decisions. See the following reports:  NREL: \u001CValue of Distributed Energy Resources Largely Depends on Three Things: Location, Location, Location.\u001D Available at: https://emp.lbl.gov/news/value-distributed-energy-resources Electric Power Systems

* Required fields

Research: \u001CValuing Distributed Energy Resources for Non-Wires Alternatives.\u001D Available at: https://www.sciencedirect.com/science/article/pii/S0378779624004073 Explore multiple scenarios that integrate potential futures for distributed energy resource adoption and other demand-side technology, in order to understand how DERs could enable additional loads from electrification. Ensure next RFP invites participation from distributed energy resources and aggregated distributed energy resources that are able to meet the energy, capacity, and grid services needs identified in the RFP. Integrate any competitive distributed energy resource bids from RFPs into future IRPs as selectable resources in the supply-side resource table. Include future scenarios that evaluate interaction of DERs and electrification. Include a sensitivity that evaluates the interactive effects between high distributed energy generation adoption and high electrification. Incorporate use of the Energy Infrastructure Reinvestment act to retire or repurpose eligible resources as a scenario or sensitivity to understand the potential impacts on unit retirement date and replacement portfolio.

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**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.
NREL: \u001CValue of Distributed Energy Resources Largely Depends on Three Things: Location, Location, Location.\u001D Available at: https://emp.lbl.gov/news/value-distributed-energy-resources Electric Power Systems Research: \u001CValuing Distributed Energy Resources for Non-Wires Alternatives.\u001D Available at: https://www.sciencedirect.com/science/article/pii/S0378779624004073

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**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.

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**PacifiCorp Response:**

a) Does the distributed generation study include any locational forecasting of DER adoption more specific than state level?

   *There is no locational forecasting in this study*

b) Does the IRP evaluate any interactive effects between distributed energy resource adoption and other customer-sited technologies? *For example*, interactive effects between high DER adoption and high electrification, or high adoption of EVs?

   *We do include the private generation forecast in our baseline projections, and also use that forecast to inform battery forecasts for the DR programs as well. We do use the expected case and not a high generation case for our reference case projections.*

c) In the June 26 - 27 presentation, slide 42 states \u001CNet-billing states tied to avoided cost forecast from IRP.\u001D In this context, does avoided cost refer to PURPA rates for qualifying facilities? Or something else? How are forecasts for future avoided costs developed?

   *The avoided cost forecast for net-billing states reflects the hourly marginal energy values for locations around the Company's system based on the 2023 IRP preferred portfolio. The hourly energy values are weighted for each of the hourly profiles for different private generation technology types. Avoided cost does not refer to PURPA rates for qualifying facilities.*

d) In the June 26 - 27 presentation, slide 42 states the value of backup power is \u001CIncluded in customer benefits of PV + Battery technology.\u001D How specifically is the value of backup power used as an input to the \u001Chigh\u001D forecast?

* Required fields

*The value of backup power is used as a direct annual benefit in the economic analysis portion of the modeling process. This influences customer paybacks and other economic metrics which are inputs in the ultimate adoption curves.*

e) Why does PacifiCorp believe that it is appropriate to assume no value for backup power in the \u001Cbase\u001D case as well as the \u001Clow\u001D case?

*As discussed on stakeholder calls, the scenarios were created to provide a bandwidth of potential DER adoption futures, and the value of backup power was added in the high case to simulate enhanced adoption tied to actual customer value placed on having backup power.*

f) What assumptions does the distributed generation study include about how customer batteries are dispatched? For example, how many hours, how many days a year, or which hours?

*Part of the modeling process includes an hourly billing analysis that requires customer load and resource dispatch shapes. Battery dispatch is determined by reducing onsite energy use and customer demand charges (where applicable). The batteries are assumed to charge/dispatch daily (one cycle/day), and the total hours and time of day is determined by individual customer load shapes and onsite energy use.*

g) Does the presence of solar/storage systems in the adoption forecasts result in a different load profile than solar alone?

*The solar profile in the solar+storage configuration would not change, but storage is used to reduce onsite customer load and demand charges where applicable. Please see Figure 3-1 in the 2023 report*[1] *as an example.*

h) Does the load forecast account for the load effects of a customer dispatching their battery, for example in response to a time of use rate?

*Please see Figure 3-1 in the 2023 report*[1] *as an example.*

i) Have PacifiCorp\u0019s past RFPs allowed for distributed generation resources to bid into the RFP? For example, could a virtual power plant bid into an RFP as a potential resource?

*PacifiCorp's 2022 All-Source RFP allowed for all resource types, including demand response resources, which could be a type of virtual power plant.*

Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com

Thank you for participating.

[1] "2023-2042 PRIVATE GENERATION FORECAST Behind-The-Meter Resource Assessment: PacifiCorp." Feb 2, 2023. Available online: PacifiCorp_Private_Generation_Resource_Assessment.pdf

* Required fields

# PacifiCorp - Stakeholder Feedback Form (027)

## Integrated Resource Plan

PacifiCorp (the Company) requests that stakeholders provide feedback to the Company upon the conclusion of each public input meeting and/or stakeholder conference call, as scheduled. PacifiCorp values the input of its active and engaged stakeholder group, and stakeholder feedback is critical to the IRP public input process. PacifiCorp requests that stakeholders provide comments using this form, which will allow the Company to more easily review and summarize comments by topic and to readily identify specific recommendations, if any, being provided. Information collected will be used to better inform issues included in the IRP, including, but not limited to the process, assumptions, and analysis. In order to maintain open communication and provide the broader Stakeholder community with useful information, the Company will post appropriate feedback on the IRP website based on your selection below.

Date of Submittal 2024-08-09

*Name: Kate Bowman Title:

*E-mail: kbowman@votesolar.org Phone: (801) 872 - 3234

*Organization: Vote Solar

Address:

City: State: Zip:

Public Meeting Date comments address: ☐ Check here if related to specific meeting

List additional organization attendees at cited meeting:

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.

Tax Credits

☒ Check here if you want your Stakeholder feedback and accompanying materials posted to the IRP website.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.

Questions: In the June 26 - 27 presentation, slide 6 describes Washington UTC requirements related to the IRA/IIJA. Will the policy statement developed to meet WUTC requirements only describe and apply to Washington load and resources, or system-wide load and resources? In the June 26 - 27 presentation, slide 5 states (regarding the ITC and the PTC): \u001CThe IRP has included these credits on all future resources built through 2037\u001D and \u001CBased on location or development, resources can be eligible for a bonus credit \u0013 ONLY the location bonus is applied in modeling.\u001D Does the IRP make any resources available for low-income bonus incentives, including the low-income incentive for solar on commercial and multifamily properties? Does the IRP model availability of the Energy Communities bonus adder for eligible resources? Recommendations: Incorporate the Energy Infrastructure Reinvestment Act financing into the IRP analysis, either by including a tranche of resources that are eligible for the bonus adder (reflected by incrementally lower costs) or by decrementing eligible resource costs to reflect the the availability of the Energy Infrastructure Reinvestment Act financing across a large portion of PacifiCorp\u0019s service territory.

**PacifiCorp Response (8/16/2024):**

Each model run is made with requirements appropriate for the states participating in those requirements. Once model runs are completed representing all states, the portfolio results are integrated, capturing all modeled state requirements in one portfolio. The integration process ensures that each state’s best portfolio remains whole and that each resource is shared according to which portfolios included the resource. This approach combines individual selectivity based on each states’ requirements while also avoiding potential overbuild.

* Required fields

Resources that are eligible for Production Tax Credits or Investment Tax Credits have a base level of 100% of the credit applied. Yes, only the location bonus is assumed for those resources which would be located in eligible coal communities. The IRP has not assumed the additional bonus for meeting American manufacturing thresholds as that bonus is outside the bounds of what can be reasonably determined or assured in planning.

As discussed in the August 14-15, 2024 Public Input Meeting, sensitivities will be performed assuming highly discounted resources based on assuming high levels of IIJA participation and assuming the pass-through of those benefits to PacifiCorp.

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**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.

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**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.

---

Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com

Thank you for participating.

* Required fields

# PacifiCorp - Stakeholder Feedback Form (028)

## Integrated Resource Plan

PacifiCorp (the Company) requests that stakeholders provide feedback to the Company upon the conclusion of each public input meeting and/or stakeholder conference call, as scheduled. PacifiCorp values the input of its active and engaged stakeholder group, and stakeholder feedback is critical to the IRP public input process. PacifiCorp requests that stakeholders provide comments using this form, which will allow the Company to more easily review and summarize comments by topic and to readily identify specific recommendations, if any, being provided. Information collected will be used to better inform issues included in the IRP, including, but not limited to the process, assumptions, and analysis. In order to maintain open communication and provide the broader Stakeholder community with useful information, the Company will post appropriate feedback on the IRP website based on your selection below.

Date of Submittal 2024-08-09


*Name: Stanley Holmes

Title:

*E-mail: stholmes3@xmission.com

Phone:

*Organization: Utah Citizens Advocating Renewable Energy (UCARE)

Address:

City: Salt Lake City State: UT Zip:


Public Meeting Date comments address: ☐ Check here if related to specific meeting

List additional organization attendees at cited meeting:

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.
PLEXOS Modeling and Differential Coal Quality Cost Impacts

☒ Check here if you want your Stakeholder feedback and accompanying materials posted to the IRP website.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.
A review of the 2023 IRP documents suggests that PLEXOS modeling does not distinguish between different quality grades of coal that may be used in PacifiCorp electricity generation units; nor does PLEXOS analyze how fuel quality gradients could factor into least-cost, least-risk portfolio selection. Variations in sulfur, ash minerals, and moisture content between coal grades could significantly affect costs associated with coal supply acquisition and inventory maintenance, greenhouse gas emissions reduction, and waste disposal among other considerations. Coal grades vary not only between mines but sometimes within the same mine, with some customers getting the preferred grade and others purchasing lower quality coal. In Utah, PacifiCorp EGUs might face price competition with Bonanza and Intermountain Power Project (IPP) coal EGUs --plus foreign exports-- for the best grades of coal, which may sometimes be in short supply. The Intermountain Power Authority, which owns IPP, has reported to Utah state entities that "coal costs are rising significantly" and that it "hasn't received its contracted [coal] tonnage requirements from suppliers for at least nine years." Unsatisfied with the quality of coal received from Wyoming, IPA has imported coal from as far away as Indiana. The Jackson Walker Final Report for Feasibility of Intermountain Power Plant gives an idea of the coal quantity and quality issues facing operators of coal EGUs in Utah. The 2025 IRP should address variations in least-cost, least-risk factors if PacifiCorp coal EGUs burn different fuel grades, given what inventory and availability conditions may suggest or necessitate. For the 2025 IRP, please specifically identify and, for comparative resource cost purposes, assess: 1) Grades and amounts of coal currently being used in PacifiCorp EGUs...by individual EGU and in total. 2) Sources of coal from which PacifiCorp currently purchases, and could purchase, fuel. This includes sources where PacifiCorp has a proprietary interest, such as the Fossil Rock Mine (aka. Cottonwood Tract; formerly Mountain Trail Mine), and those sources that are third-party owned. 3) Modeling assumptions and sensitivity scenarios for: ... the use of different grade

* Required fields

coal fuels and the MWh production costs by grade; ... conditions where competition for better grade fuel significantly increases costs of acquisition; ... costs to reduce emissions and other pollutants resulting from the use of lesser grade fuels; and, ... potential additional operations and maintenance costs, and accident liability costs, resulting from reopening geologically challenged mines, such as Fossil Rock Mine.

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**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.
IPA purchases coal from Indiana: https://www.argusmedia.com/en/news-and-insights/latest-market-news/2595473-utah-power-plant-takes-illinois-basin-coal Jackson Walker Report on IPA/IPP: https://le.utah.gov/interim/2023/pdf/00004542.pdf March 21, 2024 SITLA Agenda (Cottonwood Tract / Fossil Rock Mine): https://www.utah.gov/pmn/files/1098477.pdf SITLA's royalty rate reduction incentive to reopen Fossil Rock mine: https://www.utah.gov/pmn/files/1103161.pdf

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**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.
For the 2025 IRP, please specifically identify and, for comparative resource cost purposes, assess: 1) Grades and amounts of coal currently being used in PacifiCorp EGUs...by individual EGU and in total. 2) Sources of coal from which PacifiCorp currently purchases, and could purchase, fuel. This includes sources where PacifiCorp has a proprietary interest, such as the Fossil Rock Mine (aka. Cottonwood Tract; formerly Mountain Trail Mine), and those sources that are third-party owned. 3) Modeling assumptions and sensitivity scenarios for: ... the use of different grade coal fuels and the MWh production costs by grade; ... conditions where competition for better grade fuel significantly increases costs of acquisition; ... costs to reduce emissions and other pollutants resulting from the use of lesser grade fuels; and, ... potential additional operations and maintenance costs, and accident liability costs, resulting from reopening geologically challenged mines, such as Fossil Rock Mine.

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**Response (8/28/2024):**

- The PLEXOS model used in the development of the IRP accounts for coal cost on a BTU-adjusted basis. The effect of other coal quality characteristics, such as Sulfur content, Ash content, etc., on plant operations are manifest in the operations & maintenance costs assumed for each individual coal unit. These costs are included as variable costs in the PLEXOS model.
- For clarification purposes, PacifiCorp does not own mines in Utah, including the Fossil Rock mine.
- The Company is considering using high coal costs in the high gas/high CO2 case, where the proposed high coal costs would be three times the expected costs.

Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com

Thank you for participating.

* Required fields

# PacifiCorp - Stakeholder Feedback Form (029)
## 2025 Integrated Resource Plan

PacifiCorp (the Company) requests that stakeholders provide feedback to the Company upon the conclusion of each public input meeting and/or stakeholder conference calls, as scheduled. PacifiCorp values the input of its active and engaged stakeholder group, and stakeholder feedback is critical to the IRP public input process. PacifiCorp requests that stakeholders provide comments using this form, which will allow the Company to more easily review and summarize comments by topic and to readily identify specific recommendations, if any, being provided. Information collected will be used to better inform issues included in the 2025 IRP, including, but not limited to the process, assumptions, and analysis. In order to maintain open communication and provide the broader Stakeholder community with useful information, the Company will generally post all appropriate feedback on the IRP website unless you request otherwise, below.

Date of Submittal 8/9/2024


*Name: Sarah Puzzo, Regulatory Associate
Logan Mitchell, Climate Scientist and Energy Analyst

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Address:

City: State: Zip:


Public Meeting Date comments address: ☐ Check here if not related to specific meeting

List additional organization attendees at cited meeting:

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.

- Modeling coal costs and risks in the 2025 IRP planning process

☒ Check here if you want your Stakeholder feedback and accompanying materials posted to the IRP website.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.

In November 2022, we submitted a stakeholder feedback form requesting information about coal supply chain issues resulting from the Lila Canyon Coal Mine fire and for ongoing updates as the situation evolved.[1] At the time, the Lila Canyon coal mine fire was an emerging situation, and PacifiCorp would not speculate about potential impacts. Since then however, the Company has not provided any updates to stakeholders in the 2025 IRP public input meetings. Yet in recent months coal supply issues have been addressed at length in other forums:

- Docket No. 24-035-13: In their audit of PacifiCorp's fuel inventory prices, the Division wrote about PacifiCorp's fuel inventory report and described coal fuel supply disruptions and other force majeure events at coal mines that affected coal supplies in Utah. Many of the details of the report are redacted, however.[2]
- Docket No. 24-035-04: In his Direct Testimony, Ramon Mitchell provides another, more comprehensive description of the situation and its impact on the Company's application for a rate increase.[3] Mitchell's testimony reveals an extensive list of issues affecting coal supplies and costs in Utah:
    - "In 2022 through 2024, the coal market experienced strained conditions. The unprecedented increase in coal prices, instability in coal supply and overall market fluctuations have caused adverse impacts to the Company and other large consumers. This negative impact is due to multiple factors, including but not limited to: (1) increased coal demand due to high domestic natural gas prices; (2) low inventories at coal-fired power plants; (3) increased demand abroad for coal exports; (4) international and domestic supply chain constraints; (5) labor and material shortages; and (6) weather events and general market inflation.

      Moreover, the Lila Canyon mine fire removed approximately 25 percent of Utah coal production and disrupted the same portion of the Company's coal supply needs in Utah. On November 18, 2023, the Company was informed that the Lila Canyon mine will not reopen and will be permanently closed. The

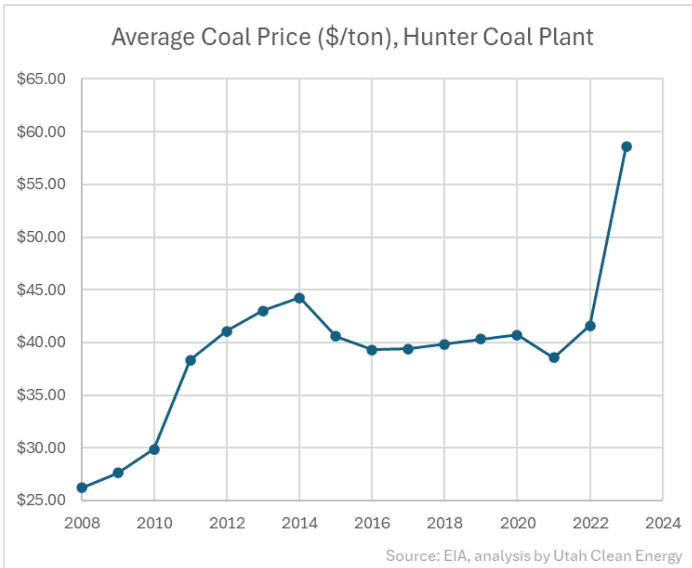
[1] See https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2023-irp/2023-irp-comments/2023.031.%20Utah%20Clean%20Energy%2011-23-22%20(with%20response).pdf.
[2] See https://pscdocs.utah.gov/electric/24docs/2403513/333586RdctdDPUCmnts4-30-2024.pdf.
[3] See https://pscdocs.utah.gov/electric/24docs/2403504/334494RdctdDirTstmnyRamonJMitchellRMP6-28-2024.pdf.

* Required fields

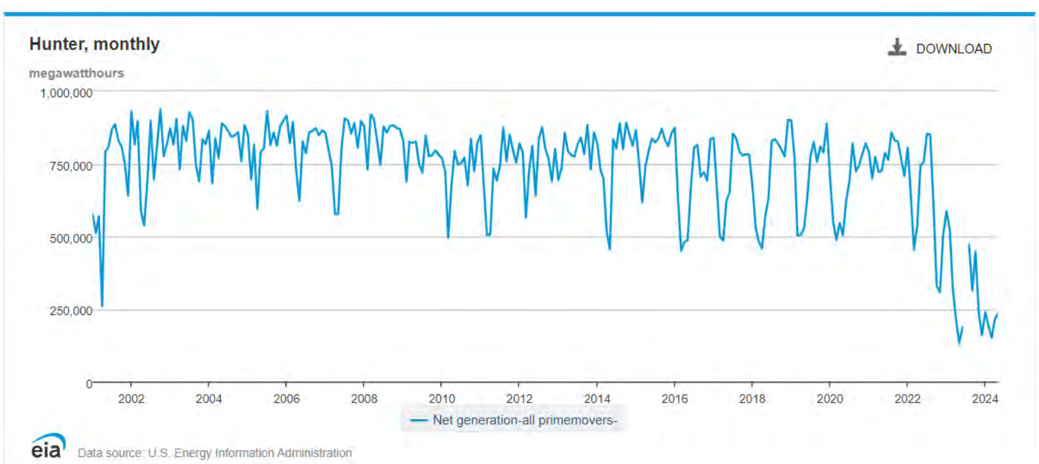
closure of Lila Canyon created a significant coal production shortfall in Utah in 2023 and will continue to have negative impacts to all large consumers, including the Company, in 2024 and potentially 2025.

In addition to the Lila Canyon mine issues in Utah, coal suppliers continue to experience issues relating to unfavorable geologic and mining conditions, delays and pressure relating to securing federal mining leases, limited availability of trucking and railway transportation for coal, long lead-times for procurement of necessary mining equipment, and limitations in availability of financing, which has put them at an increased risk of becoming insolvent. . . . The impact of these coal supply challenges is an increase of $264 million on a total-company basis. This increase is driven by increased market purchases to cover the generation reduction."[4]

Examining EIA data on coal costs provided to the Hunter coal plant, the weighted average coal prices dramatically increased by 41% in 2023 compared to prior years:[5]




In addition, DPU's audit mentioned above noted that, due to the coal supply chain issues in Utah, S&P Capital IQ reported that the capacity factor at Hunter decreased from 61.8% in 2022 to only 32.9% in 2023. This decreasing capacity factor is confirmed in EIA's electricity data browser:[6]




[4] See *id.* at 20-22.
[5] See https://www.eia.gov/coal/data/browser/#/shipments/plant/6165/?freq=A&pin=.
[6] See https://www.eia.gov/electricity/data/browser/#/plant/6165.
* Required fields

This decreasing capacity factor raises reliability concerns as explained by NERC's 2024 State of Reliability Report identifies. NERC has observed an increasing trend of weighted equivalent forced-outage rates (WEFOR) for coal resources:[7]

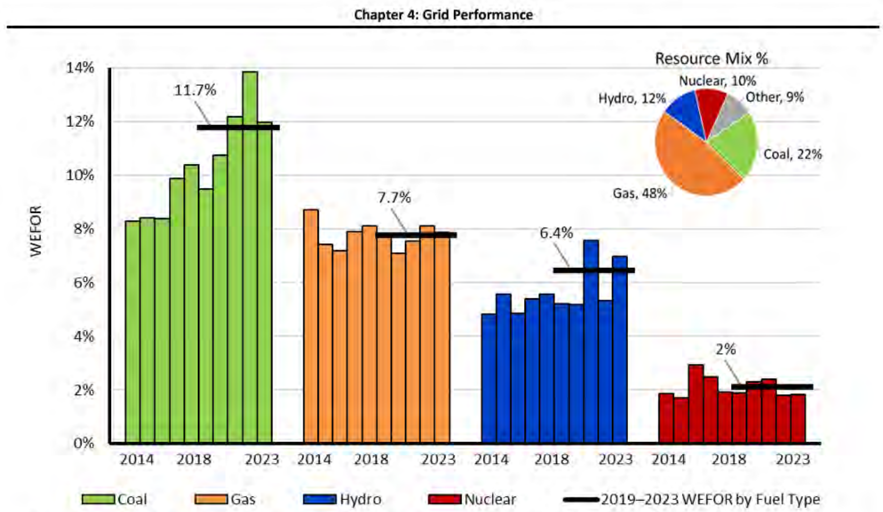


**Figure 4.5: 10-Year Annual WEFOR by Fuel Type and 2023 Resource Mix by Net Maximum Capacity**

NERC's report examined the rising trend of forced outage rates of coal and found that it correlates mostly closely with capacity factors falling below 60%. The report states:

> "Although coal-fired generation experienced a large decrease in WEFOR in 2023 (12.0% in 2023 versus 13.9% in 2022), it remains above pre-2021 rates. Due to year-over-year variability, coal generation is the primary driver of change in the overall WEFOR despite more energy being produced by both natural gas and nuclear power in 2023. ***Further investigation into baseload coal generation indicates that a unit's WEFOR negatively correlates most strongly to capacity factor. Notably, once capacity factor falls below approximately 60%, unweighted average EFORs of units begin increasing more rapidly than those between 60% and 100%.*** Although forced-outage hours are a definite contributor to lower capacity factor units' increased WEFOR, the disproportionate change appears to be driven more by maintenance/planned outage hours and decreased service hours. This aligns with industry statements indicating that reduced investment in maintenance and abnormal cycling that are being adopted primarily in response to rapid changes in the resource mix are negatively impacting baseload coal unit performance."[8]

The recent real-world experience of an exceptionally fragile coal supply chain and volatile global market prices that will cost ratepayers hundreds of millions of dollars of additional costs has exposed the true costs and risks of PacifiCorp's overreliance on coal. These risks and costs are in addition to the carbon pollution driving the changing climate and causing societal impacts like increasing wildfire risks, which are also impacting ratepayers. Therefore, it is imperative to understand how these costs and risks are incorporated in PacifiCorp's 2025 IRP, which includes the quantitative modeling aspects and the qualitative assessments.

**To better understand how spiking coal costs and risks affect the 2025 IRP modeling, we request the following information:**

1. How are coal costs represented in PLEXOS? Is there an average price used for all coal plants, or are coal prices specific to each coal plant? If an average price for all coal plants is used, how are price spikes such as those in Utah reflected in PLEXOS? Similarly, how are operations and maintenance costs reflected? What costs are excluded from the PLEXOS model because they're considered "sunk" or "fixed" costs? How many coal plants have "minimum take" requirements?

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[7] https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2024_Technical_Assessment.pdf, at 59.

[8] *Id.*

* Required fields

**Reply:**

- Coal costs in PLEXOS are specific to the plant. Costs at Bridger differ from costs at Hunter (as an example). Coal prices are based on anticipated levels of supply at a specific price point. Data is put into the model as $/MMBTU for the cost, and as a quantity of MMBTU that are available. Many coal plants (but not all) have multiple coal fuels available (an initial amount at a certain price, then a "tier 2" fuel with some other amount available at a higher price etc.).
- Fixed Operations and Maintenance (O&M) costs, and ongoing capital costs are modeled as a single levelized fixed Operations cost. Any ongoing capital that is not recovered is added to the retirement cost on a declining balance basis so the model does see an ability to "get out" of the balance of the cost by retiring the unit.
- No coal plants were modeled with minimum take requirements in the 2023 IRP. For the 2025 IRP, there is a contract in place for Hunter/Huntington that may require representation in PLEXOS modeling through 2030, after which time the requirement would be released.

2. Coal fuel costs are a critical factor to consider in terms of understanding how different resources compare to each other and contribute to overall portfolio costs. In past IRPs, Chapter 3 has had a section on Natural Gas Prices that includes Henry Hub Price Forecasts. Coal prices should also have a forecast in the 2025 IRP. A coal price forecast should start at prices consistent with current market conditions and should assume escalating prices into the future given the state of the market. Please provide the coal price forecast that is used to inform the PLEXOS model. We understand that specific coal contract terms cannot be revealed publicly, but there must be a way to aggregate the data in a meaningful way for public disclosure, for example by overall price at the plant level like the EIA data shown above.

   **Reply:**

   - The coal costs used for PLEXOS modeling is available in the Master Assumptions folders on the confidential data disc.

3. Additionally, please report the cost of coal in terms of $/MWh for the 20-year planning horizon, including fuel, fuel transportation, operations, maintenance, depreciation and any other relevant costs. Please describe which costs are included in the $/MWh and which costs are not included.

   **Reply:**

   - As discussed in the August 14-15, 2024 Public Input Meeting, coal use is heavily dependent upon the heat rate curve of the coal plants in question, and the number of MW produced by the plant varies based on the heat rate curve. O&M numbers are aggregated for each thermal unit, and are not broken out by type of O&M, so providing the specific coal related O&M Costs used by the model is not feasible. All costs associated with the delivery and combustion of coal are incorporated into the fuel price used.

4. Given recent changes in coal suppliers, please describe how variations in coal composition and quality, such as the content of sulfur, ash, and moisture, will affect coal plant heat rate and efficiency. How does coal quality affect the price of the electricity produced in $/MWh? Will changes in coal quality affect the maintenance or reliability of plants? Are coal composition factors modeled within PLEXOS for each coal plant?

   **Reply**

   - As discussed in the August 14-15, 2024 Public Input Meeting, coal fuel characteristics are all included in the fuel price and emissions rate per MMBTU of fuel consumed. These figures and characteristics are aggregated across the coal supply for each plant and are not broken out independently.

5. How will changes in coal suppliers and quality affect emissions from the plants in terms of NOx, SO2, and carbon?

   **Reply**

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- As discussed in the August 14-15, 2024 Public Input Meeting, emissions rates per MMBTU of fuel consumed are determined in forecasts provided to the IRP team. Should changes in forecasted supply quality cause these rates to change, these rates would be aggregated and updated to reflect that change. All of PacifCorp's coal units are required to meet $NO_X$ and $SO_2$ rates that are based on permitted limits. PacifiCorp will continue to meet these $NO_X$ and $SO_2$ rates regardless of coal quality. $CO_2$ emissions could increase or decrease based on coal quality and gross calorific heat value but will generally increase with lower coal rank and quality.

6. Please describe how coal fuel supply risks will affect the planning reserve margin given recent experience that supply chain disruptions caused significantly reduced capacity factors for Utah coal plants.

   **Reply**

   - PacifiCorp's IRP plans to meet the hourly demand requirements of the system, including reserves requirements. To the extent outages are higher, or reserve holding capabilities of plants are diminished, and additional resources are selected in the IRP model to meet PacifiCorp's obligations.

7. Please describe how coal plant reliability metrics are being tracked as their capacity factor decreases. How are these reliability metrics being incorporated into the 2025 IRP modeling process?

   **Reply**

   - As discussed in the August 14-15, 2024 Public Input Meeting during the Daily Shapes portion of the presentation, historical actuals are being used in modeling.

8. How are disruptions like the recent Lila Canyon coal mine fire being incorporated into stochastic risk metrics throughout the planning horizon? For example, how would a coal supply disruption in a specific year affect a given portfolio (e.g. a force majeure event in 2030 removing >25% of coal supply)? Disruptions like this should be examined for cost and reliability metrics.

   **Reply**

   - Depending on incoming requests and requirements, PacifiCorp is willing to consider a sensitivity changing coal supply assumptions.

9. In DPU's review of PacifiCorp's coal fuel supply report linked above, they discussed six PLEXOS scenarios that were run to examine coal risks (pg 8), however the DPU's description of those scenarios was partially redacted. Please provide an un-redacted and detailed description of those scenarios and the conclusions from them.

   **Reply**

   - In February 2024, PacifiCorp evaluated six different scenarios for the Hunter and Huntington Plants using different assumptions and inputs to the PLEXOS model. The base scenario assumed the coal supply agreements (CSA) at the Hunter and Huntington plants with Wolverine Fuels, the principal coal supplier in Utah, were renegotiated and amended. The alternative scenarios assumed other coal supply options and/or market conditions. The evaluation assessed the total cost of each scenario on a present value revenue requirement (PVRR) basis. The cost of the base scenario was significantly lower than the other scenarios and led to PacifiCorp's decision to amend the Hunter/Wolverine CSA and Huntington/Wolverine CSA. The following is a brief description of the different scenarios:
   - Scenario 1 - The Hunter/Wolverine CSA is amended to include additional years to the term. The prospective Fossil Rock Mine will begin to provide volumes to Hunter in 2025. The Huntington/Wolverine CSA is amended with no extension of the current 2029 term. The Utah coal market becomes stable again and generation constraints recede.
   - Scenario 2 - PacifiCorp does not sign amendments with Wolverine. Pricing is assumed to be reset to current Utah market prices which is higher than the anticipated Hunter/Wolverine and

Huntington/Wolverine amendments. The Fossil Rock Mine does not reopen and coal supply in Utah remains constrained and unstable.

- Scenario 3 - PacifiCorp does not sign amendments with Wolverine. Pricing is assumed to be reset to current Utah market prices. Wolverine does eventually reopen the Fossil Rock Mine, and the Utah coal market becomes more stable.
- Scenario 4 - PacifiCorp does not sign amendments with Wolverine. PacifiCorp's existing contracts are terminated, and the pricing is assumed to be reset to current Utah market prices plus a premium price which assumes fewer coal suppliers in the region. The Fossil Rock Mine does not reopen and coal supply in Utah remains constrained and unstable.
- Scenario 5 - PacifiCorp does not sign amendments with Wolverine. PacifiCorp receives limited Utah market coal supply for a period. PacifiCorp spends capital to build a rail unloading facility in central Utah and modify the Utah Plants to consume Powder River Basin coal.
- Scenario 6 - PacifiCorp does not sign amendments with Wolverine. PacifiCorp receives limited Utah market coal supply for a period. PacifiCorp spends capital to build a rail unloading facility in central Utah and purchases additional coal from Colorado mines.

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**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.

- See footnotes.

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**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.

- See above

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Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com
Thank you for participating.

* Required fields

# PacifiCorp - Stakeholder Feedback Form (030)

## Integrated Resource Plan

PacifiCorp (the Company) requests that stakeholders provide feedback to the Company upon the conclusion of each public input meeting and/or stakeholder conference call, as scheduled. PacifiCorp values the input of its active and engaged stakeholder group, and stakeholder feedback is critical to the IRP public input process. PacifiCorp requests that stakeholders provide comments using this form, which will allow the Company to more easily review and summarize comments by topic and to readily identify specific recommendations, if any, being provided. Information collected will be used to better inform issues included in the IRP, including, but not limited to the process, assumptions, and analysis. In order to maintain open communication and provide the broader Stakeholder community with useful information, the Company will post appropriate feedback on the IRP website based on your selection below.

Date of Submittal 2024-08-13


*Name: Katie Pappas Title:

*E-mail: kpappas56@yahoo.com Phone: 1801532365

*Organization: Ratepayer

Address: 424 K st

City: Salt Lake City State: UT Zip: 84103


Public Meeting Date comments address: ☐ Check here if related to specific meeting

List additional organization attendees at cited meeting:

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.
Proposed Rocky Mountain Power Rate Increase in Utah

☒ Check here if you want your Stakeholder feedback and accompanying materials posted to the IRP website.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.
Rocky Mountain Power, with help from the Utah legislature and governor\u0019s office, wants all of us in Utah to foot the bill, in a backward attempt to prop up what\u0019s left of the Utah coal industry. Rather than move toward a more sustainable, healthier, lower energy cost future, they are hellbent on prolonging dependence on dirty fossil fuels. Why? Ironically, the very issues their rate increases seek to address are made worse by their climate busting practices. Utah has an opportunity to be a leader in the development of several cheaper, greener energy sources that actually cost less, don\u0019t pollute our air and won\u0019t negatively impact our health. We have never factored in the external costs of burning fossil fuels but now spend billions to mitigate damage caused by climate change. Utahns deserve better. Our energy policies and decisions should be guided by science, not by politicians and corporations. Please oppose this outrageous assault on ratepayers. Katie Pappas Salt Lake City, UT

**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.

**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.

PacifiCorp Response (8/29/2024):
Thank you for your feedback. PacifiCorp uses the Integrated Resource Planning process to select the least-cost, least-risk portfolio given prevailing conditions at the time of planning. Renewable energy is a critical component of PacifiCorp's resource mixture and will make up an increasing proportion of the energy generated by the PacifiCorp system over time.

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Pages 6-7 of the 2023 IRP Update report that the preferred portfolio includes 3,749 megawatts of new solar online by 2037, 9,800 megawatts of new wind resources online by 2037, and more than 4,000 megawatts of new storage capacity online by 2037. While renewable energy plays an ever-growing role in PacifiCorp's resource mixture, PacifiCorp's diverse portfolio of resources help to ensure system reliability during critical hours. In the 2023 IRP Update, thermal resources operated at a low-capacity factor in future years but were critical in ensuring system reliability during peak load hours. PacifiCorp is committed to achieving emissions reduction targets as required by state and federal regulatory obligations and welcomes the development of alternative fuel sources that can provide a similar level of system flexibility as traditional thermal resources at reduced emissions rates.

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Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com

Thank you for participating.

* Required fields

# PacifiCorp - Stakeholder Feedback Form (031)
## Integrated Resource Plan

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Date of Submittal 2024-08-13


*Name: Jane Myers
Title:
*E-mail: myersjane2004@yahoo.com
Phone: (801) 081 - 4315
*Organization: rate payer
Address: 5317 W Wheatridge Ln
City: West Jordan State: UT Zip: 84081


Public Meeting Date comments address: 08-14-2024 ☒ Check here if related to specific meeting

List additional organization attendees at cited meeting:

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.
I am addressing the 30% rate increase that is "serving and benefiting Utah customers."

☒ Check here if you want your Stakeholder feedback and accompanying materials posted to the IRP website.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.
After returning from Scandinavia, I am shocked that we are still stressing coal in our energy policies. Even though Norway has found oil, they have 88% hydro power and are using more wind and solar. The coal is more expensive and dirtier for our unhealthy air quality in Utah than even natural gas (which is also readily available).

**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.
https://energifaktanorge.no/en/norsk-energiforsyning/kraftproduksjon/

**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.
We have roof-top solar. The transmission lines are already in existence. Batteries can be added. We should not be pursuing coal in our future plans and we should be putting in many more transmission lines for the energy needs five years from now. We should be putting in more wind production. Our air quality is steadily getting worse, which effects climate change and global warming.

PacifiCorp Response (8/29/2024):
Thank you for your feedback. PacifiCorp uses the Integrated Resource Planning process to select the least-cost, least-risk portfolio given prevailing conditions at the time of planning. Renewable energy is a critical component of PacifiCorp's resource mixture and will make up an increasing proportion of the energy generated by the PacifiCorp system over time. Pages 6-7 of the 2023 IRP Update report that the preferred portfolio includes 3,749 megawatts of new solar online by 2037, 9,800 megawatts of new wind resources online by 2037, and more than 4,000 megawatts of new storage capacity online by 2037. PacifiCorp welcomes specific suggestions to enhance cost and other input assumptions for all types of resources. These assumptions are critical inputs that drive Plexos model selections. While renewable energy plays an

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ever-growing role in PacifiCorp's resource mixture, PacifiCorp's diverse portfolio of resources help to ensure system reliability during critical hours. In the 2023 IRP Update, thermal resources operated at a low-capacity factor in future years but were critical in ensuring system reliability during peak load hours. PacifiCorp is committed to achieving emissions reduction targets as required by state and federal regulatory obligations and welcomes the development of alternative fuel sources that can provide a similar level of system flexibility as traditional thermal resources at reduced emissions rates.

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Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com

Thank you for participating.

* Required fields

# PacifiCorp - Stakeholder Feedback Form (032)

## Integrated Resource Plan

PacifiCorp (the Company) requests that stakeholders provide feedback to the Company upon the conclusion of each public input meeting and/or stakeholder conference call, as scheduled. PacifiCorp values the input of its active and engaged stakeholder group, and stakeholder feedback is critical to the IRP public input process. PacifiCorp requests that stakeholders provide comments using this form, which will allow the Company to more easily review and summarize comments by topic and to readily identify specific recommendations, if any, being provided. Information collected will be used to better inform issues included in the IRP, including, but not limited to the process, assumptions, and analysis. In order to maintain open communication and provide the broader Stakeholder community with useful information, the Company will post appropriate feedback on the IRP website based on your selection below.

Date of Submittal 2024-08-14


*Name: Sara Kenney  Title:

*E-mail: skenn4ut@gmail.com  Phone:

*Organization: N/A

Address:

City: Lehi  State: UT  Zip: 84043


Public Meeting Date comments address: ☐ Check here if related to specific meeting

List additional organization attendees at cited meeting:

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.
Carbon Dioxide Emissions

☒ Check here if you want your Stakeholder feedback and accompanying materials posted to the IRP website.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.
I object to the reduction in your renewable energy portfolio mix and the increase in emissions resulting from this decision to continue to rely on coal and fossil fuels more than renewables. Pacificorp should be able to read the room and realize just because the our legislators and conservative courts are making it easier for you to continue relying on fossil fuels, doesn't make it the right choice. Regardless of your obligation to compliance or laws, you should be thinking about the future of our children and our environment. Allowing for a long term increase in emissions compared to even the original 2023 plan, is a failure of leadership on your part. Renewable energy is cheaper, just as reliable and better for the environment and public health than coal and fossil fuels. To quote a recept op ed in the Desert by Malin Moench, " The premium that utilities now pay to use coal rather than renewables averages 30% nationally, but is 50% for RMP\u0019s Utah coal plants, according to national plant-specific cost data compiled in a recent study. From these data, we can calculate that RMP could avoid operating costs of $260 million annually by switching from coal to solar \u0014 savings large enough to pay for full battery backup for such solar facilities." Pacificorp and Rocky Mountain Power should take advantage of IRA funding to increase renewable energy now, not later on when it's too late. Do the right thing and make the switch to renewable energy now. Thank you.

**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.
https://www.deseret.com/opinion/2024/08/11/rocky-mountain-power-rate-hike-legislation-blocking-renewable-energy/

**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.

* Required fields

PacifiCorp Response (8/29/2024):
Thank you for your feedback. PacifiCorp uses the Integrated Resource Planning process to select the least-cost, least-risk portfolio given prevailing conditions at the time of planning. Renewable energy is a critical component of PacifiCorp's resource mixture and will make up an increasing proportion of the energy generated by the PacifiCorp system over time. Pages 6-7 of the 2023 IRP Update report that the preferred portfolio includes 3,749 megawatts of new solar online by 2037, 9,800 megawatts of new wind resources online by 2037, and more than 4,000 megawatts of new storage capacity online by 2037. PacifiCorp welcomes specific suggestions to enhance cost and other input assumptions for all types of resources. These assumptions are critical inputs that drive Plexos model selections. While renewable energy plays an ever-growing role in PacifiCorp's resource mixture, PacifiCorp's diverse portfolio of resources help to ensure system reliability during critical hours. In the 2023 IRP Update, thermal resources operated at a low-capacity factor in future years but were critical in ensuring system reliability during peak load hours. PacifiCorp is committed to achieving emissions reduction targets as required by state and federal regulatory obligations and welcomes the development of alternative fuel sources that can provide a similar level of system flexibility as traditional thermal resources at reduced emissions rates.

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Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com

Thank you for participating.

* Required fields

# PacifiCorp - Stakeholder Feedback Form (035)

## Integrated Resource Plan

PacifiCorp (the Company) requests that stakeholders provide feedback to the Company upon the conclusion of each public input meeting and/or stakeholder conference call, as scheduled. PacifiCorp values the input of its active and engaged stakeholder group, and stakeholder feedback is critical to the IRP public input process. PacifiCorp requests that stakeholders provide comments using this form, which will allow the Company to more easily review and summarize comments by topic and to readily identify specific recommendations, if any, being provided. Information collected will be used to better inform issues included in the IRP, including, but not limited to the process, assumptions, and analysis. In order to maintain open communication and provide the broader Stakeholder community with useful information, the Company will post appropriate feedback on the IRP website based on your selection below.

Date of Submittal 2024-08-20

*Name: John Jenks  Title:

*E-mail: john.jenks1@wyo.gov  Phone: 3078232403

*Organization: Wyoming Energy Authority

Address: 1912 Capitol Ave #305

City: Cheyenne  State:  Zip: 82001

Public Meeting Date comments address: 08-14-2024  ☒ Check here if related to specific meeting

List additional organization attendees at cited meeting:

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.
2025 IRP Study List Update

☒ Check here if you want your Stakeholder feedback and accompanying materials posted to the IRP website.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.
At the August 14, 2024 IRP Stakeholder Meeting, PacifiCorp representatives were giving updates on various IRP studies and particularly the sensitives given to each state. For Wyoming in particular, there is a line that reads, \u001CBusiness as usual.\u001D I asked a clarifying question as to what is meant by, \u001CBusiness as usual.\u001D I was curious if this meant projected load growth both in the state and throughout the service territory was being considered because if it is, there could be some concern regarding study sensitives being labeled as constant or \u001Cbusiness as usual,\u001D especially in terms of considerations with generation resources. There was quite a bit of confusion and vagueness here and the RMP representatives weren\u0019t quite sure, either. Unfortunately, the recording is missing this part on the YouTube videos, too. So largely, can PacifiCorp please clarify what is meant and what assumption are being used for \u001Cbusiness as usual?\u001D Thank you. OP

**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.

**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.
PacifiCorp should clarify and clearly articulate the assumptions being used for "business as usual" in Wyoming and how this is affecting the modeling for the 2025 IRP.

Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com

* Required fields

Thank you for participating.

**PacifiCorp Response (9/10/2024):**

Thank you for your feedback and engagement in the Integrated Resource Planning process.

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;

It is therefore not acceptable to hold load constant. PacifiCorp supports the commission's language as being necessary to produce a study that reflects a reference case which accounts for known commitments, requirements and key updates that have occurred since the 20217 IRP Update. Primarily, PacificCorp adheres to this required study, as defined by the commission, by aligning thermal retirement options in the model to those represented in the outcome of the 2017 IRP Update preferred portfolio. The study is also based on a price-policy scenario that does not have a CO2 proxy adder, which in past IRPs is referred to as the medium-gas, no CO2 (MN) scenario.

In the 2025 IRP, PacifiCorp expects to produce a business-as-usual (BAU) systemwide study for its reference case using updated inputs and forecasts, including an updated load forecast. End-of-life retirements will be assumed for all thermal resources that have not already committed to a specific future such as an established retirement date.

* Required fields

# PacifiCorp - Stakeholder Feedback Form (036)

## 2025 Integrated Resource Plan

PacifiCorp (the Company) requests that stakeholders provide feedback to the Company upon the conclusion of each public input meeting and/or stakeholder conference calls, as scheduled. PacifiCorp values the input of its active and engaged stakeholder group, and stakeholder feedback is critical to the IRP public input process. PacifiCorp requests that stakeholders provide comments using this form, which will allow the Company to more easily review and summarize comments by topic and to readily identify specific recommendations, if any, being provided. Information collected will be used to better inform issues included in the 2025 IRP, including, but not limited to the process, assumptions, and analysis. In order to maintain open communication and provide the broader Stakeholder community with useful information, the Company will generally post all appropriate feedback on the IRP website unless you request otherwise, below.

Date of Submittal: 8/27/2024


*Name: Rose Monahan Title: Staff Attorney

*E-mail: Rose.monahan@sierraclub.org Phone: 415-977-5704

*Organization: Sierra Club

Address: 2101 Webster Street, Suite 1300

City: Oakland State: CA Zip: 94612


Public Meeting Date comments address: ☐ Check here if not related to specific meeting

List additional organization attendees at cited meeting:

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.

- Demand side management
- Granularity Adjustments
- Reliability Adjustments
- EIR
- Federal Regulations
- Resource Availability

[X] Check here if you want your Stakeholder feedback and accompanying materials posted to the IRP website.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.

Sierra Club provides the following recommendations for PacifiCorp's 2025 IRP. Additional information supporting these recommendations is attached to this Stakeholder Feedback Form

1. **Demand Side Management**
   a. EE Supply Curves
      i. Provide sufficient time for review of the EE supply curves and the opportunity to suggest changes prior to modeling.
      ii. Remove any cost thresholds above which EE measures cannot be considered for IRP model selection, and instead include all possible EE measure bundles in the supply curve and allow the model to select the bundles that minimize cost across the entire resource portfolio
      iii. Ensure that administrative costs are aligned with real-world administrative costs for utility EE portfolios (i.e., less than 10%)
      iv. Assume at a minimum EE measure incentive levels at 75-100%, and consider incentive levels exceeding 100% (e.g., 125%, 150%)
      v. Additional flexible load options:

1. Include bidirectional charging as a resource option
2. Consult with the Vehicle Grid Integration Council on best practices for developing new vehicle to grid program opportunities
3. Consider new flexible load options for new large load customers, particularly data centers

vi. Consider incremental heat pump costs relative to both a heating and cooling baseline technology, informed by recent research on heat pump costs and available federal incentives, including information already compiled by Calmus on behalf of PSE (and excerpted below).

b. Include EE/DR bundles as potential reliability adjustment resources

**Reply:**

a. i. Thank you for your feedback. The energy efficiency options for use in the IRP modeling are developed by an outside consultant, Applied Energy Group (AEG). AEG has presented their findings and plan related to the Conservation Potential Assessment (CPA) in several IRP Public Input Meetings within the 2025 IRP Planning cycle. Planning and timelines for the CPA were presented in the January 25, 2024 Public Meeting with information starting on slide 19. Further conversation and opportunity for feedback related to the CPA took place in the May 2 and July 17/18 Public Input Meetings (starting on slide 5 and 75 respectively) and will be included in the upcoming September meeting. AEG provided forums and opportunities for engagement outside of these meetings. Due to the time required to develop CPA outcomes and also continuously review stages of work with feedback from stakeholders, this timeline would be challenging to accelerate beyond the acceleration that has already occurred.

ii. PacifiCorp does not, nor has it ever, applied any cost threshold above which DSM-EE measures cannot be considered for selection in the IRP.

iii. Thank you for the suggestion. PacifiCorp is currently working with AEG to examine the way it will be modeling these administrative costs across all states in the 2025 CPA, based on historical annual report trends.

iv. Thank you for the suggestion. PacifiCorp is currently working with AEG to examine modeled EE measure level incentives for the 2025 CPA.

v. AEG will be sharing details about demand response modeling methodology in the upcoming public input meeting September 25-26, 2024.

vi. Thank you for sharing the relevant Cadmus study. The CPA currently does include both baseline type costs for heat pumps in the characterization, in line with Rocky Mountain Power programs.

b. All resources (including EE/DR bundles) are eligible to be selected to cover ST reported, shortfall-adjusted load in following iterations of the LT model.

**2. Granularity Adjustments**

a. Reporting Recommendations

i. Report steps taken to reduce out-of-model granularity adjustments, including any differences between the 2025 and 2023 methodology, including whether decreasing fixed cost (slide 44, March meeting) was part of the process in 2023 and if not, how that addition is improving the granularity adjustment process.

ii. Clearly report methodology, values, and impacts of adjustments.

b. Modeling Recommendations

i. Granularity adjustments should primarily be applied to flexible resources, i.e. resources the value of which is not fully captured in the LT model because of the lower temporal resolution: energy storage and peakers.

ii. Ensure that the energy value of a resource's output in the LT Model and that in the ST model include the same cost components for a consistent comparison.

**Reply:**

a. The Granularity Adjustment is inherently an "in-model" adjustment as it directly takes model outputs and feeds them back into PLEXOS. In order to review model results and verify reasonability of model outcomes, there is a reporting "pause" in this step, however there could be a direct loop setup in PLEXOS that would integrate the differences between LT and ST values directly in model runs.
    i. The Granularity Adjustment has always either been a cost increase (for items the LT views as more valuable than the ST) or a cost decrease (for items the LT views as less valuable than the ST).
    ii. In the 2023 IRP update, granularity adjustments were calculated automatically on each portfolio based on the difference between the LT and ST value of each resource. This value was fed back into the LT models for each following iteration (i.e. iteration 2 used values from iteration 1; iteration 3 used values from iteration 2 etc.). This methodology was discussed in the narrative of the 23 IRP Update, and the values of all granularity adjustments were included on the data disc.

b. Granularity adjustments are applied to all resources, and applying a granularity adjustment to only a subset of resource types would skew the value of those resources relative to other options. The automatic calculation of the difference between values in the LT and ST is part of an iterative process, which has been reviewed by modeling consultants with Energy Exemplar. PacifiCorp's process of using a granularity adjustment has been described by Energy Exemplar as a "gold standard" of model use. Additionally, a member of the PacifiCorp IRP team has been asked to present on PacifiCorp's granularity adjustment and reliability load adder at an Energy Exemplar symposium in Seattle on October 15. The company expects this modeling approach will help other clients obtain better results.

    The granularity adjustment is calculated automatically in the same way for each resource from the PLEXOS LT and ST output and can be viewed in reporting on the data disc.

## 3. Reliability Adjustments

a. Reporting Recommendations
    i. Provide PLEXOS output files for the initial and reliability-adjusted portfolios, as well as a spreadsheet mapping the initial and reliability-adjusted portfolios, together with a list of the resources that have been added, removed, delayed, or in any way adjusted by the Company, and a justification for this choice.

b. Modeling Recommendations
    i. Provide details on the rationale and methodology of reliability adjustments during the public input meetings prior to the filing of the draft IRP.
    ii. Provide stakeholders with an opportunity to recommend alternative reliability adjustments.
    iii. Resources options considered for addressing the identified reliability issues should include renewable energy sources, energy storage, and demand side resources.

**Reply:**

a. In the 2023 IRP Update, PacifiCorp allowed the model to endogenously select all resources and made no resource additions outside the model for the purpose of achieving reliability. As such, there is no reporting of resources that have been manually adjusted by the company because the company did not manually adjust resource selections.

Reliability in the 2023 IRP update was achieved by adding hourly shortfalls identified by the ST model to the base LT load file and allowing the PLEXOS model to select a new suite of resources based on this additional load. All LT model reports were published on the Data Disc, and by comparing iteration 1 to iteration 2 it is possible to see the change in resources (due to both the granularity adjustment and also the additional load).

In light of stakeholder feedback, PacifiCorp has confirmed with Energy Exemplar consultants this is an appropriate use of model functionality and data. Energy Exemplar consultants have described PacifiCorp's iterative approach as the "gold standard".

b. Given the above process, where the model endogenously selects resources for reliability, responses are as follows:
    i. The model is endogenously selecting resources based on the methodology of adding shortages to the load file; there is no exogenous selection of resources thus no rationale/methodology to explicitly explain.
    ii. Stakeholders are welcome to recommend alternatives to the endogenous selections at any point, but note there are no exogenous reliability adjustments, and given the updated process, no exogenous additions or adjustments to the portfolio are considered.
    iii. The model considers ALL modeled resource options to cover the load; resources are selected using PLEXOS core functionality and data.

**4. Energy Infrastructure Reinvestment Program**

a. Reporting Recommendation
    i. Provide an update on PacifiCorp's efforts to secure EIR financing from the DOE Loan Program Office and any analysis that has been conducted to assess the associated benefits.

b. Modeling Recommendation
    i. Incorporate financing opportunities made available under the EIR program, which can enable the closure of coal plants, the replacement of fossil resources with cleaner alternatives, and the development of transmission infrastructure. Specifically, PacifiCorp should conduct:
        1. A scenario in which transmission network upgrade costs in Cluster Areas 1, 2, 4, 12, and 14 are reduced by 30 percent; and
        2. A scenario in which EIR financing is assumed for early retirement and replacement of Jim Bridger Units 3 and 4, Huntington, Hunter, and Wyodak. In this scenario the model should be allowed to select the economic retirement of those units assuming EIR financing.

**Reply:**

a. Thank you for your feedback. Opportunities are being evaluated and pursued; PacifiCorp will provide a public update of these activities when available. Sensitivity studies are planned to assess high, medium and low levels of program adoption relevant to the IRA and IIJA.
b. As discussed in the August Public Input Meeting, PacifiCorp is evaluating an extremely low cost renewables scenario which leverages the lowest required return on investment at the standard Investment Tax Credit rate for a resource (assuming federally subsidized financing), the most aggressive cost decline curves from NREL, and extending the construction timing eligibility for Production Tax Credits indefinitely. PacifiCorp believes modeling these parameters for future proxy resources is a reasonable representation of

being able to acquire resources while successfully leveraging every possible program.

5. **Compliance with Federal Regulations**
   a. Clean Air Act 111(d) Regulation & CO2 Price Assumptions
      i. Compliance with the EPA 111(d) rule should be modeled as part of the base model, not as a variant or price-policy scenario (MR). The five price-policy scenarios (including MM), as defined in the 2023 IRP analysis can be used, with all of them requiring Section 111(d) compliance of existing coal and new gas resources, while the N, M, H, and SC assumptions will define the CO2 price in addition to the required EPA 111(d) compliance.
      ii. CO2 prices should be included in LT, but the Company should also conduct and report ST results without the carbon cost included in the dispatch decisions.
      iii. Cumulative carbon costs associated with each portfolio, although not included in dispatch decisions, should be reported through a post-optimization calculation.
      iv. Variants that perform well should have LT runs presented for all price-policy scenarios.
   b. Regional Haze Program
      i. As part of the base model (i.e., included in all portfolio runs), include an SCR requirement at Hunter 2, Huntington 1 and Huntington 2. Additionally, require that the model select either SCR or SNCR at Naughton, Wyodak, and Dave Johnston 1, 2, and 4.
      ii. As a variant case, include an SCR requirement at all five units at Hunter and Huntington, while keeping the same modeling assumptions at the Wyoming units.

**Reply:**

a. A $CO_2$ Price has always been intended to be representative of future policy driving towards the reduction in $CO_2$ emissions (excepting where there is a legally binding price in existence such as the Social Cost for Washington, or the Carbon adder at Chehalis). Including EPA 111(d) compliance in the Low/No and Medium/No price-policy scenarios would be counter to evaluating portfolios developed in an environment where policy is ultimately not implemented. Given the Medium $CO_2$ case is intended to represent "expected" future policy, replacing this assumption with a currently articulated future policy (EPA 111(d)) seems the most prudent action for the Medium case. The High case would be intended to explore a future where the cost of compliance is even higher than meeting EPA 111(d). Note that the Social Cost of Greenhouse Gasses price-policy view is mandated under Washington law.
   i. See the reply to part a) above
   ii. PacifiCorp currently evaluates candidate portfolios under other price-policy scenarios and will continue to do so. Reporting on each of these is provided in the document and on the data disc.
   iii. PacifiCorp would be interested to understand what types of calculations Sierra Club would propose. The currently provided emissions output data may be sufficient if the desire is to apply additional emission costs on a post-model basis.
   iv. Given the number of model runs required, PacifiCorp will be developing portfolios for variants under an MN future. As discussed in response to part ii, these portfolios will be evaluated under all identified price-policy futures. Variant portfolios will not be developed under every price-policy scenario.

b. Please see responses below:
   i. Emissions reductions from these technologies are available in practice, and the effective cost per ton of potential emissions reductions from installation of SNCR or SCR can be calculated the model results. Because both SNCR and SCR

technology have little impact on resource operating parameters such as heat rate and maximum output, there would be little impact on system dispatch from including those options in the model.

The model will have an availability to select CCUS (including SCR technology) at each of these locations and can make that selection independent of the selections at other sites, excepting locations where other environmental compliance requirements would prevent continued coal-fired operation:

1. Naughton 1&2 which are currently slated to either gas convert in 2026 or retire
2. Dave Johnston 1&2 which are currently slated to retire in 2028 with an option to gas convert to continue operating after that date.

ii. As above, the model will be able to select CCUS (including SCR technology) at the above sites.

**6. Resource Availability**

a. Evaluate whether there are resource bids proposed in the 2022 RFP that could be available prior to 2028 and include those resource options in the model

**Reply:**

a. Any cluster study/transmission options that are eligible to be in service prior to 2028 will be included as proxy resource options starting in 2027.

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**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.

Please see attached

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**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.

Please see above

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Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com
Thank you for participating.

* Required fields

# Feedback on Paci�iCorp 2025 IRP

## Demand Side Management

### 1. *Review of EE Supply Curves*

In the May 2, 2024 stakeholder meeting, Paci�iCorp provided the following timeline for the Conservation Potential Assessment:

| Timeframe | Milestone | Public Input Request |
|---|---|---|
| ~~January 25, 2024~~ | ~~Present on Scope of Work~~ | ~~Additional input on scope~~ |
| ~~March 14, 2024~~ | ~~Share Draft EE & DR Measure List~~ | ~~Provide feedback on included measures~~ |
| ~~April 8, 2024~~ | ~~Finalize Measure List~~ | ~~Feedback incorporated~~ |
| May 2, 2022 | Share Key Drivers of Potential and Assumptions | Review methodology and resources |
| September 2024 | Present Draft Results and Share Measure Data | Review materials and provide feedback |
| October 2024 | Present Final Supply Curves | Review changes made due to feedback |
| November 2024 | Draft CPA for Review | Provide input on draft report |
| January 2024 | Publish Final Report | With feedback incorporated |

This suggests that the EE supply curves will not be available for review until September or October, which may be too late for additional changes prior to being committed as inputs to the IRP modeling. Sierra Club requests that there be suf�icient time for review of the EE supply curves and the opportunity to suggest changes prior to modeling. In particular, Sierra Club is concerned about the following potential issues:

a. *Exclusion of Measures from Supply Curve*: In the �inal 2023 CPA Report, the following methodological approach was described:

> In general, this study did not consider the cost of energy efficiency measures, as this analysis is performed within PacifiCorp's IRP. However, because, by default, the technical (and achievable technical) assumes that the highest efficiency equipment option will be adopted by all customers at the time of replacement, this has the potential to skew the amount of cost-effective potential. For example, assuming that all customers adopt high-cost SEER 24 central air conditioners would not only create a large amount of high-cost potential that the IRP model would be unlikely to select, but it would also reduce the available potential for lower-cost non-equipment measures that can save cooling load (e.g., insulation). To account for this, the achievable technical potential excluded equipment measures with significantly high upfront costs unlikely to be deemed economic within the IRP. This screening used a levelized cost threshold of $160/MWh for California, Utah, Idaho, and Wyoming, and a higher threshold of $175/MWh for Washington to reflect the 10% conservation credit applied within the IRP for measures in that state.

In other words, Paci�iCorp's approach was to set an arbitrary cost threshold, above which EE measures cannot even be considered for IRP model selection – even if those measures could be an optimal part of the overall portfolio. Sierra Club disagrees with this approach since it assumes, without any supporting evidence, that higher cost measures would not be selected by the model and should therefore be excluded from consideration. While it is certainly possible that higher cost measures will be selected in fewer quantities, there is no logical basis for initially excluding them from the supply curve, and thus from possible selection in the IRP model. A better approach would be to include all possible EE measure bundles in the supply curve and simply allow the model to select the bundles that minimize cost across the entire resource portfolio.

b. *Admin Costs*: Measures included in the 2023 CPA assumed administrative costs that were exceedingly high, even up to 48% of the total cost in some cases. Typically, administrative costs for utility EE portfolios are less 10%. For example, administrative costs for Rocky Mountain Power's DSM portfolio in the 2023 program year were approximately 2% of the total portfolio budget.[1]

c. *Incentive Levels*: During the May 2, 2024 PIM, Paci�iCorp explained that EE measure costs included an assumed incentive level that varies by state as shown below:

| Field | Washington | California | Oregon | Wyoming | Utah | Idaho |
|---|---|---|---|---|---|---|
| CE Test | TRC, 10% adder | TRC | TRC | UCT | UCT | UCT |
| Measure Cost | $1,000 | $1,000 | $1,000 | n/a | n/a | n/a |
| Incentive Paid | n/a | n/a | n/a | $430 (43%) | $380 (38%) | $390 (39%) |
| Utility Admin % | 48% | 45% | 29% | 48% | 22% | 40% |
| Admin Spend | $480 | $450 | $290 | $480 | $220 | $400 |
| Cost for Bundling | $1,480 | $1,450 | $1,290 | $910 | $600 | $790 |

** Administrative costs will be updated during the 2025 study

However it is unclear if additional quantities of EE measure bundles can be selected by the IRP model at higher incentive levels. Sierra Club recommends that the model be provided with EE bundles at higher incentive levels -- and correspondingly higher quantities -- as an option for the model to select. This re�lects that overall customer adoption of EE measures would generally increase as the level of incentives increases. At a minimum, incentive levels should be set at 75% and 100% of incremental measure costs. Additionally, there is no reason to cap the incentive level at 100% of the incremental cost of the measure. It may be more cost effective from a resource portfolio perspective to increase the adoption of EE

1 https://www.paci�icorp.com/content/dam/pcorp/documents/en/paci�icorp/environment/dsm/utah/UT_Energy_Ef�iciency_and_Peak_Reduction_Report_2023.pdf

measures, even if that means increasing the incentive levels above 100%. Paci�iCorp should consider incentive levels at 125% and/or 150% of the incremental cost of the measure.

d. *Additional Flexible Load Options*:

Sierra Club appreciates Paci�iCorp's consideration of new �lexible load options as part of its demand-side resource portfolio. However, Sierra Club recommends that two additional �lexible load options be included as part of the overall portfolio.

First, while Paci�iCorp has included an Electric Vehicle Direct Load Control, this appears to be limited to one-way managed charging of EVs. In reality, many new EV models – including both LDVs (e.g. Ford F150) and MD/HDVs (e.g. school buses) – are capable of bidirectional charging, often referred to as "vehicle to grid", "vehicle to building", "V2X" or "V2G." These technologies are currently being deployed around the country to serve as a grid resource during times of peak need. This stands to provide roughly twice the grid capacity bene�it as simple managed charging, and only a small fraction of EV participation is needed to reach potentially several hundreds of MW of grid resource. Sierra Club recommends that Paci�iCorp include this as a resource option in its IRP modeling. Additionally, Sierra Club recommends that Paci�iCorp consult with the Vehicle Grid Integration Council on best practices for developing new V2X program opportunities that draw upon lessons learned from other utility programs.[2]

Third, Sierra Club recommends that Paci�iCorp consider new �lexible load options for the emerging subset of new large load customers. For example, one data center company has recently reported its ability to temporarily shift computing load based on the needs of the grid.[3]

*e. Treatment of Heat Pump Costs:*

Recent technological advances in cold-climate heat pumps, along with incentives offered through the In�lation Reduction Act mean that there should be substantial consideration of this technology as a potential component of Paci�iCorp's DSM portfolio. Heat pumps can offer a more ef�icient form of cooling than traditional AC units or resistive heating. Sierra Club recommends that Paci�iCorp consider incremental heat pump costs relative to both a heating and cooling baseline technology. For example, the incremental cost of heat pumps relative to a new AC cooling unit may be substantially less than the incremental cost versus a gas furnace. Additionally, the assumed incremental costs should be informed by recent research on heat pump costs and available federal incentives. Sierra Club recommends that

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[2] https://www.vgicouncil.org/resources

[3] https://cloud.google.com/blog/products/infrastructure/using-demand-response-to-reduce-data-center-power-consumption

Paci�iCorp incorporate information recently compiled by Cadmus on behalf of PSE for this purpose.[4] The table below was excerpted from the Cadmus report.

**Table 11. Potential Impact of 25C Tax Credit and HEEHRA Rebate on Cost of Heat Pumps (80% to 150% AMI)**

| Equipment | Base Cost Estimate | Est. 25C Tax Credit Value | Est. HEEHRA Rebate[a] | Net Cost |
|---|---|---|---|---|
| **Centrally Ducted ASHP** | | | | |
| Centrally Ducted ASHP – Base | $14,800 | [b] | [b] | $14,800 |
| Centrally Ducted ASHP – Dual Stage | $17,175 | [b] | [b] | $17,175 |
| Centrally Ducted ASHP – ENERGY STAR | $17,800 | $2,000[c] | $8,000 | $7,800 |
| Centrally Ducted ASHP – Cold Climate | $19,425 | $2,000[c] | $8,000[d] | $9,425 |
| Centrally Ducted ASHP – Dual Fuel | $11,277 | [b] | [b] | $11,277 |
| Centrally Ducted ASHP + Furnace – Dual Fuel | $16,250 | [b] | [b] | $16,250 |
| **Ductless Mini-Split Heat Pump (assumed 3 tons)** | | | | |
| Ductless Mini-Split Heat Pump – Base | $13,443 | [b] | [b] | $13,443 |
| Ductless Mini-Split Heat Pump – ENERGY STAR | $14,886 | $2,000[c] | $7,443 | $5,443 |
| Ductless Mini-Split Heat Pump – Cold Climate | $15,246 | $2,000[c] | $7,623[d] | $5,623 |

Sources: 26 C.F.R. § 25C; *An Act to provide for reconciliation pursuant to title II of S. Con. Res. 14*, Public Law 117-169 (2022): 1817–2090. https://www.congress.gov/117/plaws/publ169/PLAW-117publ169.pdf

[a] While this table shows the HEEHRA rebate estimate for residents making 80% to 150% of AMI, residents making less than 80% AMI would be expected to receive the full $8,000 for all qualifying heat pumps, given the cost estimates used.

[b] Equipment is not assumed to meet the efficiency criteria for ENERGY STAR or for CEE Tier 3.

[c] Equipment meeting ENERGY STAR or different CCHP specifications may not meet CEE Tier 3 criteria.

[d] Equipment meeting CCHP specification may not qualify for ENERGY STAR designation.

### 2. *EE/DR bundles should be included as potential "reliability adjustment" resources.*

In the 2023 IRP, Paci�iCorp's modeling approach included a "reliability adjustment" step in which incremental resources were added after the initial ST model runs to account for any energy shortfalls. However, the potential set of resource options added to address reliability needs did not include any Energy Ef�iciency or Demand Response resources. Sierra Club recommends that Paci�iCorp update its approach to allow EE and DR resources to be added in the reliability adjustment step. Notably, this step is conducted outside of the cost-optimization, and thus there is no need to consider "cost-effectiveness" in the traditional sense. In other words, the addition of supply side resources to address residual reliability needs are agnostic to cost. Similarly, additional reliability-driven EE resources should be considered for inclusion, even if they would not screen a traditional cost-effectiveness test. This would be the only way to consider EE resources on an equal playing �ield with supply-side resources. Additionally, Paci�iCorp should clearly identify all the resources added as part of the reliability adjustment step, including EE/DR resources. To the extent that EE/DR resources are included, Paci�iCorp should also update its EE/DR implementation plans to

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[4] https://apiproxy.utc.wa.gov/cases/GetDocument?docID=3616&year=2022&docketNumber=220066

include these additional reliability-driven EE/DR resources. This might be accomplished by including a “reliability adder” as part of the cost-bene�it evaluation, and/or when selecting the level of customer rebate/incentive.

## Granularity & Reliability Adjustments

In its comments for the 2023 IRP analysis, Sierra Club has expressed concerns for the manual adjustments performed by the Company to the resource portfolios. Those include reliability and granularity adjustments. While both are addressing real modeling concerns, they do so in a way that is not fully transparent and is excessively impacting the �inal portfolios. These manual adjustments undermine the role of a modeling process and tool like PLEXOS, while stakeholders spend time reviewing inputs and outputs that in the end are overwritten by the Company’s adjustments.

Granularity Adjustments

For the granularity adjustments, Sierra Club is concerned that based on previous reviews, coal units might be receiving a signi�icant and unjusti�ied adjustment which reduces their �ixed cost and could result in keeping uneconomic units online. The example of “swapping” driven by Granularity Adjustments presented during the March 14, 2024 meeting is especially concerning as it shows the impact those adjustments have on the portfolio. For example, between phases 3 and 4 wind grows by more than 75%, which shows the impact that the Company’s out-of-model changes can have on the �inal portfolios.

During the same meeting, the Company stated that “The Granularity Adjustment re�lects the marginal value of the LAST MW of a resource that is added, and in runs that are reliable, this last MW has less value than the last MW in an unreliable run.” This raises concerns with respect to the Company’s modeling process and sequence of steps: if the granularity adjustment is performed prior to the reliability adjustment step, then an energy shortfall could result in an unreasonably high energy value for coal units based on the $1000/MWh shortfall price. However, that energy shortfall could be addressed during the reliability step signi�icantly reducing the energy value of said coal units. Furthermore, the energy value of coal units is partly determined by the company’s assumed coal prices , which Sierra Club and other stakeholders have expressed concerns about.

Sierra Club provides the following recommendations:

*Reporting Recommendations*

- Report steps taken to reduce out-of-model granularity adjustments. Explain any differences between the 2025 and 2023 methodology, including whether decreasing �ixed cost (slide 44, March meeting) was part of the process in 2023 and if not, how that addition is improving the granularity adjustment process.

- Clearly report methodology, values, and impacts of adjustments. Provide clearly labeled workpapers that include the initial adjustments, and the adjustment values for each iteration, as well as the model results and PLEXOS output �iles (and a spreadsheet that clearly explains the adjustments and �ile names of each iteration). For each of the portfolios presented, explain why the iterative process stopped at the �inal portfolio.

*Modeling Recommendations*

- Granularity adjustments should primarily be applied to �lexible resources, i.e. resources the value of which is not fully captured in the LT model because of the lower temporal resolution: energy storage and peakers.
- Ensure that the energy value of a resource's output in the LT Model and that in the ST model include the same cost components for a consistent comparison. In its Response to Sierra Club Data Request 29 for the 2023 IRP analysis, Paci�iCorp noted that "existing plants are no longer capitalizing initial build costs whereas proxy resources do capitalize these items over the study horizon impacting net �igures." This statement implies that the granularity adjustment is impacted by whether the unit is existing or a new addition (through the inclusion of initial build costs). However, initial build costs are not relevant for the granularity adjustment which is meant to capture only the �lexibility value that the LT model might not be fully capturing because of its lower time resolution. Thus, Sierra Club recommends that for the granularity calculation the energy value should not be net of annualized initial build costs, even for new resources.

Reliability Adjustments

Reliability adjustments also have a signi�icant impact on the �inal portfolios as the Companies choose to delay, add, or subtract resources. Sierra Club has analyzed its concerns regarding the Company's practice of adding resources and delaying retirements to address the reliability issues, a concern that was shared by Staff in its comments, requesting increased transparency and an effort to reduce the out-of-model adjustments. Paci�iCorp has not shared any details about how the reliability adjustments will inform the 2025 IRP.

Reporting Recommendations

- Provide PLEXOS output �iles for the initial and reliability-adjusted portfolios, as well as a spreadsheet mapping the initial and reliability-adjusted portfolios, together with a list of the resources that have been added, removed, delayed, or in any way adjusted by the Company, and a justi�ication for this choice.

Modeling Recommendations

- Provide details on the rationale and methodology of reliability adjustments during the public input meetings prior to the �iling of the draft IRP.
- Provide stakeholders with an opportunity to recommend alternative reliability adjustments. These alternatives should be evaluated in parallel to those selected by Paci�iCorp, with an opportunity for revisions and feedback from stakeholders prior to the IRP �iling.
- Resources options considered for addressing the identi�ied reliability issues should include renewable energy sources, energy storage, and demand side resources.

## Energy Infrastructure Reinvestment (EIR) Program:

In the Commission's Order adapting Staff's recommendations 24-073, the Commission included a recommendation coming from Sierra Club's comments:

> #21: In the 2025 IRP/CEP Paci�iCorp shall provide an update on Paci�iCorp's efforts to secure Energy Infrastructure Reinvestment (EIR) �inancing from the DOE Loan Program Of�ice. Assume EIR �inancing through the DOE Loan Program Of�ice in the Preferred Portfolio or include a variant portfolio that optimizes resource additions and retirements under the assumption of EIR �inancing.

Paci�iCorp has not shared any details about how this recommendation will be included in the Company's analysis.

Reporting Recommendation:

- Provide an update on Paci�iCorp's efforts to secure EIR �inancing from the DOE Loan Program Of�ice and any analysis that has been conducted to assess the associated bene�its.

Modeling Recommendation:

- Incorporate �inancing opportunities made available under the EIR program, which can enable the closure of coal plants, the replacement of fossil resources with cleaner alternatives, and the development of transmission infrastructure. Speci�ically, Paci�iCorp should conduct:
    - A scenario in which transmission network upgrade costs in Cluster Areas 1, 2, 4, 12, and 14 are reduced by 30 percent; and
    - A scenario in which EIR �inancing is assumed for early retirement and replacement of Jim Bridger Units 3 and 4, Huntington, Hunter, and Wyodak. In this scenario the model should be allowed to select the economic retirement of those units assuming EIR �inancing.

## Compliance with the EPA 111(d) rule and CO2 price

In its 2023 IRP analysis Paci�iCorp evaluated resources under �ive price-policy scenarios assuming different CO2 and natural gas prices:

- MN: Medium natural gas/No federal CO2 regulations
- MM: Medium natural gas/Medium CO2 cost
- HH: High natural gas/High CO2 cost
- LN: Low natural gas/No federal CO2 regulations
- SC: Medium natural gas / Social cost of greenhouse gases

For the 2025 IRP, Paci�iCorp is lowering the high CO2 forecast for the HH scenario and replacing the MM with a new price-policy scenario:

- MR: Medium natural gas/current federal CO2 regulations, under Section 111 of Clean Air Act

<u>Modeling Recommendations</u>

- Compliance with the EPA 111(d) rule should be modeled as part of the base model, not as a variant or price-policy scenario (MR). The �ive price-policy scenarios (including MM), as de�ined in the 2023 IRP analysis can be used, with all of them requiring Section 111(d) compliance of existing coal and new gas resources, while the N, M, H, and SC assumptions will de�ine the CO2 price in addition to the required EPA 111(d) compliance. Speci�ically:
    - All coal units should be modeled based on three compliance options identi�ied in the August public input meeting:
        - Continued Operations/retirement by end of 2031.
        - CCS by end of 2031, no retirement obligation.
        - Natural Gas/Alternative Fuel: co-�iring of at least 40%natural gas or similar emission reductions from an alternative fuel, starting 2030. 100% natural gas or alternative fuel starting 2039. This compliance option should include any conversion costs as well as incremental fuel supply and transportation costs.
    - If new combustion turbines or combined cycle resources are available for selection in the model, they should be compliant with EPA 111(d):
        - CCS by January 1st, 2032 (or other technology option meeting the standard)
        - Operating with an upper limit capacity factor of 40 percent during each year.
- CO2 prices should be included in LT, but the Company should also conduct and report ST results without the carbon cost included in the dispatch decisions.

Reporting Recommendations

- Cumulative carbon costs associated with each portfolio, although not included in dispatch decisions, should be reported through a post-optimization calculation.
- Variants that perform well should have LT runs presented for all price-policy scenarios.

## Compliance with the EPA Regional Haze Rule

In August 2024, EPA proposed to disapprove both Wyoming and Utah's Round 2 Regional Haze State Implementation Plans (SIPs). EPA's �inal decision on Wyoming and Utah's SIPs are expected by November 22, 2024. In EPA's proposed disapproval of Wyoming's SIP, EPA faulted Wyoming for failing to consider pollution emission reductions from some of the state's largest sources, including Jim Bridger, Wyodak, Naughton, and Dave Johnston. This indicates that pollution controls are likely to be required at Paci�iCorp's Wyoming coal �leet. At a minimum, it indicates a regulatory risk that controls will be required. Paci�iCorp should factor this risk into its long-term planning, where the Company examines a variety of possible futures.

In EPA's proposed disapproval of Utah's SIP, EPA stated that "[s]ince installing SCR at Hunter Unit 3 would achieve signi�icant emissions reductions at a cost of $4,401/ton (below Utah's $5,750/ton cost-effectiveness level) and the State did not address this issue in its SIP submission, we �ind that Utah unreasonably rejected SCR for this unit." EPA also stated, "[t]he information in the record indicated that installation of SCR, at an estimated cost of $5,979-$6,533/ton NOx reduced, may well be cost-effective for Hunter Units 1 and 2 and Huntington Units 1 and 2 (or some subset of these units)." Accordingly, there is also regulatory risk that SCR will be required at all �ive units at Hunter and Huntington, which should also be accounted for in Paci�iCorp's IRP.

Modeling Recommendations

- As part of the base model (i.e., included in all portfolio runs), include an SCR requirement at Hunter 2, Huntington 1 and Huntington 2. Additionally, require that the model select either SCR or SNCR at Naughton, Wyodak, and Dave Johnston 1, 2, and 4.
- As a variant case, include an SCR requirement at all �ive units at Hunter and Huntington, while keeping the same modeling assumptions at the Wyoming units.

## Resource Availability

During the July public input meeting, Paci�iCorp presented modeling details around supply side resources, including energy storage, solar, wind, geothermal, nuclear, and gas turbines. Energy storage and solar are assumed to have a 12 month construction duration while onshore wind a 12-24 month construction duration. The soonest commercial operation date possible for the three resource types is assumed to be 2028. However, there might be resource bids proposed in the 2022 RFP, which could be potentially available prior to 2028. Sierra Club recommends that any such resources are identi�ied and included as resource options in the model.

# PacifiCorp - Stakeholder Feedback Form (037)

## Integrated Resource Plan

PacifiCorp (the Company) requests that stakeholders provide feedback to the Company upon the conclusion of each public input meeting and/or stakeholder conference call, as scheduled. PacifiCorp values the input of its active and engaged stakeholder group, and stakeholder feedback is critical to the IRP public input process. PacifiCorp requests that stakeholders provide comments using this form, which will allow the Company to more easily review and summarize comments by topic and to readily identify specific recommendations, if any, being provided. Information collected will be used to better inform issues included in the IRP, including, but not limited to the process, assumptions, and analysis. In order to maintain open communication and provide the broader Stakeholder community with useful information, the Company will post appropriate feedback on the IRP website based on your selection below.

Date of Submittal 2024-08-30

*Name: Stanley Holmes
Title: Outreach Coordinator
*E-mail: stholmes3@xmission.com
Phone:
*Organization: Utah Citizens Advocating Renewable Energy (UCARE)
Address:
City: Salt Lake City State: UT Zip:
Public Meeting Date comments address: 08-14-2024 ☐ Check here if related to specific meeting
List additional organization attendees at cited meeting:

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.
State Updates; Multi-State Protocol; RMP Separation from PacifiCorp; Near-, Mid-, Long-Term Acquisition Strategies

☒ Check here if you want your Stakeholder feedback and accompanying materials posted to the IRP website.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.
Please identify all potential system-wide resource planning impacts if RMP separates from PacifiCorp, or if a Utah-Idaho-Wyoming consortium of state managers takes control, at near-, mid-, and long term stages of the 2025 IRP planning horizon. Utah state legislators recently expressed concern about the current PacifiCorp structure and requested a "restructuring" report from RMP...due in November 2024. Suggest Multi-State Protocol advisory group of UT/WY/ID/WA/OR/CA state representatives be resurrected and meet asap.

**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.
https://utahnewsdispatch.com/2024/08/21/utah-legislature-asks-rmp-to-restructure-its-rate-system-and-split-pacificorp/,
https://le.utah.gov/Interim/2024/pdf/00002837.pdf?r=169

**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.
Please ensure that implications of recent Utah state legislative actions are raised in relevant sections of the September 25-26 PIM agenda and that RMP describes what it plans to address in its November 2024 restructuring report to the Utah Legislature.

**PacifiCorp Response: (9/16/2024)**

* Required fields

PacifiCorp anticipates including this topic in its 2025 IRP September 25-26 public input meeting agenda. However, review and planning for Utah's legislative request is ongoing, and the company will not be able to provide a comprehensive response in this timeframe.

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Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com

Thank you for participating.

* Required fields

# PacifiCorp - Stakeholder Feedback Form (039)
## Integrated Resource Plan

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Date of Submittal 2024-09-10

*Name: Nancy Kelly  Title:

*E-mail:  Phone:

*Organization: Western Resource Advocates

Address:

City:  State:  Zip:

Public Meeting Date comments address:  ☐ Check here if related to specific meeting

List additional organization attendees at cited meeting:

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.
INFORMATION REQUEST, MARKET VARIANT REQUESTS

☒ Check here if you want your Stakeholder feedback and accompanying materials posted to the IRP website.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.
INFORMATION REQUEST

1. Please provide more information supporting the addition of the new Wyoming hub.

In developing the 2023 IRP Update, PacifiCorp added a 500 MW hub in Wyoming that it had never previously modeled. This same modeling assumption is carried forward into the 2025 IRP.

The stated justification for this new modeling assumption is provided in a single sentence on page 41 of the IRP Update and in a single bullet on page 42 of the July Public Input Meeting ("PIM") presentation. The July PIM explanation is more complete than the 2023 IRP Update explanation. It states: "the addition of the Wyoming energy market reflects improved access to additional utilities facilitated by the construction of Gateway South."

More information is needed to justify this 500 MW addition. If this market is assumed to be available in all hours of every year over the 20-year planning period, this is the equivalent of adding a 500 MW facility in Wyoming but with no forced outage rate.

Please provide, at a minimum, the following information:

- Does PacifiCorp assume these 500 MWs are available in all hours of every year over the 20-year planning period? If so, why does PacifiCorp believe this energy will continue to be available in all hours across the 20-year planning period? If not, what products is PacifiCorp assuming will be available and in what time periods?
- Which utilities can PacifiCorp now access that it couldn't previously?
- What experience does PacifiCorp have with these sellers?
- How liquid and deep does PacifiCorp expect this new market hub to be? Please provide all supporting documentation.

2. Please provide the price forecast for the Wyoming market hub.

Page 39 of the July PIM presentation shows Quarter 2 price forecasts for the market hubs, but no market price forecast is provided for the new Wyoming hub. Please provide the forecast for this hub that will be used for modeling.

* Required fields

MARKET VARIANT REQUESTS

1. Market Variant One
   - Model the MM scenario, but without assuming access to a Wyoming hub.

Justification: In other proceedings, the Company has described declining liquidity at all market hubs and has shown that market reliance is a large risk and significant driver for increases in net power cost requests across the states. This variant tests what happens if the new market hub does not play out as PacifiCorp forecasts.

2. Market Variant Two
   - Model the MM scenario, but without assuming access to a Wyoming hub.
   - Additionally, assume the short-term market caps at the other five hubs extend out as is currently modeled over the first 3 years only. In the 4th year, reduce the availability at each hub by 50%, and in the fifth year, reduce the availability by 75%.

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**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.

Justification: In each IRP, PacifiCorp assumes that market hubs are liquid for five years and then dry up. This has the effect of encouraging ongoing near-term market reliance which may or may not be in customers' best interest. This variant tests what happens if the new market hub does not play out as PacifiCorp forecasts and markets tighten earlier and in a more gradual manner than PacifiCorp has assumed.

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**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.

**PacifiCorp Response:**

PacifiCorp's transmission system in eastern Wyoming is connected to the following other utilities, including:

- NorthWestern Energy (in Montana)
- Western Area Power Administration - Rocky Mountain Region
- Tri-State Generation and Transmission
- Black Hills Power
- Basin Electric Power Cooperative

Through these entities, there are also connections to the Southwest Power Pool (SPP) in Western Nebraska.

These entities have limited access to liquid western markets, like Mid-Columbia and Palo Verde, and are thus more likely to have resources available when supplies at those markets are restricted. These connections are not new, but with Gateway South in service, it is also more likely that incremental supply sourced from these neighboring utilities would be able to reach PacifiCorp's major load centers in Utah.

Like the other markets modeled in the IRP, the short-term (ST) modeling reflects hourly balancing transactions in all hours, though unlike the other markets, the Company is not modeling market sales in Wyoming, as the resource mix in the area is typically dominated by low-cost thermal resources and wind and likely to be limited by transmission constraints. For modeling purposes, purchases from the Wyoming market were assumed to have the same price as Palo Verde.

While this "all hours" treatment is consistent with other market modeling, PacifiCorp recognizes that it is not really a firm commitment. Importantly, under the Western Resource Adequacy Program (WRAP), balancing transactions without a specified source will not count toward forward showing capacity requirements. PacifiCorp is modelling WRAP capacity requirements in the 2025 IRP starting in 2028, and does not intend to count capacity from markets (including Wyoming) as part of WRAP compliance for modeling purposes. Note that in practice "market" products exist that would meet forward showing requirements, e.g. annual hydro slice purchases, and WRAP compliance could be met with short-term or long-term products.

While markets may not count toward WRAP compliance, the Western Energy Imbalance Market (WEIM) already provides opportunities to balance resources in real-time across a broad footprint that covers most of the Western interconnect. CAISO's Enhanced Day-ahead Market (EDAM) is expected to provide further optimization by coordinating day-ahead decisions. The WEIM and EDAM are likely to enable greater system balancing under nearly all conditions, though PacifiCorp recognizes they are not replacements for the firm resources needed for WRAP compliance.

For the first time the 2025 IRP will separate the balancing function of markets from the reliability aspects, which should address some of the concerns identified. PacifiCorp appreciates the suggestions about market scenarios and intends to examine how WRAP requirements and market reliance interact in the 2025 IRP results before considering further analysis.

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Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com

Thank you for participating.

* Required fields

# **PacifiCorp - Stakeholder Feedback Form** (040)

Integrated Resource Plan

PacifiCorp (the Company) requests that stakeholders provide feedback to the Company upon the conclusion of each public input meeting and/or stakeholder conference call, as scheduled. PacifiCorp values the input of its active and engaged stakeholder group, and stakeholder feedback is critical to the IRP public input process. PacifiCorp requests that stakeholders provide comments using this form, which will allow the Company to more easily review and summarize comments by topic and to readily identify specific recommendations, if any, being provided. Information collected will be used to better inform issues included in the IRP, including, but not limited to the process, assumptions, and analysis. In order to maintain open communication and provide the broader Stakeholder community with useful information, the Company will post appropriate feedback on the IRP website based on your selection below.

Date of Submittal 2024-09-12


*Name: Jim Himelic Title:

*E-mail: jhimelic@firstprinciples.run Phone:

*Organization: Renewable Northwest

Address:

City: State: Zip:


Public Meeting Date comments address: ☐ Check here if related to specific meeting

List additional organization attendees at cited meeting:

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.
Modeling of transmission upgrades in PAC's PLEXOS model

☒ Check here if you want your Stakeholder feedback and accompanying materials posted to the IRP website.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.

Current General Understanding of PAC IRP Transmission Planning

Below is a high-level description of the overall PAC TX planning process as RNW currently understands it. Please review and correct any of the statements listed below that are either inaccurate or incomplete.

• PacifiCorp (PAC) models two types of transmission upgrade options in its PLEXOS IRP model:

o Incremental (INC) transmission (TX) transfer capacity: Network upgrades that increase the transfer capacity between transmission regions (e.g., the exchange of electricity between the Wyoming East and Bridger transmission regions).

o Interconnection (CON) TX upgrades: Network upgrades that enable candidate generators and storage devices to interconnect within one of PacifiCorp's transmission regions (e.g., allowing a resource to interconnect in the Summer Lake transmission region).

> **Reply**: The effect of the INC and CON distinction in the model is as described, however INC and CON transmission upgrade options are a categorization for IRP modeling only, and don't have any inherent tie to particular kinds of transmission studies or outcomes. For example, upgrades for ERIS interconnection may result in incremental transfer capability. Also, a transmission option that has incremental transmission between locations in the real world but is located completely within an IRP topology bubble will be represented in the modeling as a CON item.

Figure 1: PacifiCorp Preliminary 2025 IRP Transmission Topology

• For the near-term planning horizon, both the INC and CON transmission upgrade options are derived from previous cluster studies conducted by PacifiCorp's transmission team.

* Required fields

**Reply**: For the near-term planning horizon, previous cluster studies (or previous serial queue studies) conducted by PacifiCorp's transmission planning team generally provides the most up-to-date information, but because cluster study requests do not comprehensively cover PacifiCorp's system, transmission planning also provides estimates for locations not covered in cluster study results.

• PAC's IRP team gathers information from multiple Cluster Studies (e.g., 1, 2, 3, 4) and uses the latest available data from the most recent round of studies up until a specified cutoff date.

**Reply**: The IRP team generally relies on transmission planning to provide forecasted transmission upgrade options, though it has supplemented with more recent Cluster Study results at times in consultation with transmission planning.

o Within each cluster study, a contingent facilities list is provided (for both ERIS- and NRIS-related upgrades) and specifies whether these facilities are binding for the projects under current evaluation.
o If a listed contingent facility is binding, that associated TX work must be completed before any of the projects under current consideration can interconnect with PAC's TX system.

**Reply**: In general, contingent facilities must be in place before a resource can interconnect. However, Provisional Interconnection Service can allow for projects to interconnect early using unutilized interconnection capability. A separate request queue and process exists for this service. For example, one project in a cluster might be able to interconnect even though the cluster as a whole requires contingent facilities. Alternatively, if an earlier queued resource (from a prior cluster) has selected a later COD, interconnection capacity might be available without additional upgrades prior to that COD.

• Within each cluster study, the required TX upgrade projects can be categorized as either project-specific or shared costs.
o Charges related to interconnection facilities and station equipment are project-specific.
o Network upgrades are pooled expenses, with the amount assigned to each project allocated on a proportional basis according to the nameplate capacity of the requested POI.
• PacifiCorp's IRP PLEXOS model assigns TX upgrade-related constraints as a continuous variable (i.e., non-integer).
o As a result, the model can access a portion of the incremental INC or CON MWs that are enabled by the upgrade, paying only for a proportional share of the total project cost.

**Reply**: Cost allocation for interconnection facilities and network upgrades are outlined in the PacifiCorp Open Access Transmission Tariff (OATT) Section 39.2.1. Currently, system network upgrades are allocated on a proportional basis according to the nameplate capacity, however, once FERC Order 2023 becomes effective system network upgrades will be allocated based on the proportional impact of each individual generation facility in the Cluster that relies on the need for a specific system network upgrade or set of upgrades. Station equipment costs can be shared if multiple requests are submitted for the same interconnection point. Station equipment costs have distinct allocation in the cluster study process and are classified either as direct assigned facilities or network upgrades. The station equipment classified as network upgrades are refunded to interconnection customers on the same basis as other network upgrades.

Transmission upgrades are intended to be modeled as integer decisions, for example, Gateway South and Boardman to Hemingway cannot readily be scaled down. PacifiCorp does recognize that certain upgrades could be reduced if a smaller quantity of resources was selected and the remaining requests were withdrawn, such that linear treatment might be realistic. Given the difficulty of modeling integer transmission upgrades, and the iterative nature of PacifiCorp's modeling, resolution of integer values for transmission upgrades may require variant analysis (with and without), and may be limited to major near-term projects.

General Questions Related to Cluster Studies / Transmission Modeling in the IRP
• Is it correct to assume that all CON-related TX options are derived from Energy Resource Interconnection Service (ERIS)-related required TX upgrades listed in PAC's cluster studies?

* Required fields

o If not, what is the source of PAC's assumptions for CON-related TX upgrade options, as defined in the PLEXOS model?

• Similarly, is it correct to assume that all INC-related TX options are derived from Network Resource Interconnection Service (NRIS)-related required TX upgrades listed in PAC's cluster studies?

o If not, what is the source of PAC's assumptions for INC-related TX upgrade options as they are defined in the PLEXOS model?

**Reply**: The IRP model does not distinguish ERIS and NRIS interconnection options. Any transmission upgrades that do not result incremental transfer capability in the IRP topology are categorized as "CON", and all others that do result in incremental transfer capability in the IRP topology are categorized as "INC". The IRP model reflects PacifiCorp Energy Supply Management's transmission rights, which it uses on behalf of its retail customers, plus the rights it could receive as a result of potential transmission upgrades. Transmission rights are managed through the transmission service request (TSR) process, which is distinct from interconnection. Interconnection, including NRIS, does not provide transmission service. The transmission topology and transmission upgrade modeling in the IRP is a significant simplification of these various processes, so as to facilitate proxy-based long-term planning.

• How are ERIS-enabled generator and storage resource options configured in the PLEXOS model?

o Does this configuration differ at all for those resources that are NRIS-enabled? If so, how?

**Reply**: ERIS and NRIS are not distinguished in the IRP, though transmission upgrade options that are included in the IRP may have come from studies of either type. Because the NRIS study is intended to include costs for upgrades needed to transfer resources to load, it is more likely to receive an "INC" categorization.

• Are the line transfer capacities listed in the PLEXOS model - for both existing and incremental upgrade options - based solely on firm transmission service?

o Does PAC's PLEXOS model include any non-firm, as-available transmission service for candidate INC upgrade projects?

**Reply**: The IRP model includes firm transmission capability and doesn't include any non-firm capability.

• Is there a separate configuration in PLEXOS for resources listed as Designated Network Resources (DWR) (which use network TX to transfer power from the facility site to PAC load centers) compared to non-DWR resources (which require point-to-point service to transfer power to load)?

**Reply**: IRP modeling does not distinguish the type of transmission service and includes both network and existing long-term firm point-to-point capacity rights held by PacifiCorp Energy Supply Management.

• Near-term TX upgrade options defined in PLEXOS - both INC and CON types - are sourced from PAC TX's cluster studies, but what is the source of these longer-term options that the PAC IRP team uses when defining these items in the model?

o Is it correct to assume that projects originating from PAC TX are exogenously prescribed in PLEXOS (i.e., not modeled as decision variables)?

o Will a complete list of all these manually specified TX upgrades be included in the 2025 IRP data disk, along with relevant data such as the first year of service and the regional incremental INC and CON MW amounts?

• When porting over the TX options from the cluster studies into the PLEXOS model, how does the PAC IRP team account for the prerequisite TX upgrades associated with higher-priority interconnections listed in each cluster study?

o Are all the listed TX projects exogenously defined in PLEXOS, or are some of the upgrades treated as candidate options and thus represented by decision variables in the model?

**Reply:** Longer-term options are forecasts provided by PacifiCorp Transmission. Generally, the upgrades have previously been identified in a cluster study, though withdrawn requests may have eliminated particular upgrades. The forecast can also cleanly cut off the megawatt quantities once a particular upgrade is fully utilized, whereas the cluster study identifies requirements for the entire cluster and has to round up to the next major upgrade even if it is only needed in part. In general, the IRP only models transmission options, and does not track costs for contingent facilities or upgrades that are required regardless of the model selections, as this is not required as part of the optimization.

Unless the study is a transmission-related sensitivity, all available options are the same for every study. These options have been presented in the 2025 public input meeting series and will be presented in the filed 2025 IRP. In addition, each LT model's accompanying outcome file reports transmission options selected for the relevant portfolio, including the selected in-service year for the upgrade.

o Does the PAC IRP team embed any dependency logic in their PLEXOS model to ensure all upstream requirements are fully resolved before a candidate TX upgrade project is eligible for selection by the model?

**Reply**: Yes. Transmission upgrades are generally cumulative and each successive upgrade in a location is subject to a constraint in PLEXOS requiring the previous upgrade(s) in that location to have been completed. Some upgrades are required for multiple areas or later upgrade options.

• Does the affected system information listed in each cluster study have any impact on PAC's IRP modeling process?

**Reply**: If impacts on affected systems are known, it could be reflected by the timing of the earliest in-service year of an upgrade option. Unless there are known costs for affected systems, costs only reflect the impacts on PacifiCorp's system.

• In the June Stakeholder meeting, there was a discussion on the interaction between PAC TX's long-term projects and PAC IRP's long-term plans. As a follow-up to that conversation, can you please address the following questions:
o Is the overall amount of CON and INT TX service across PAC's entire TX topology updated to reflect the impacts of these projects at their assumed in-service dates?
 For each of these long-term projects sourced from the company's TX group, will the 2025 IRP data disk include the incremental CON and INT regional capacities associated with each of these discrete projects?

**Reply**: All of the transmission upgrade options for the 2025 IRP are sourced from PacifiCorp Transmission. Given the lead time for major transmission upgrades, if a major transmission option is included in PacifiCorp Transmission's long-term plan, particularly in the next few years, the IRP is likely to model it as available starting in the identified in the plan as it is difficult to compress existing timelines that have already been developed and for which planning is underway. The IRP model would still be allowed to select a later date. The timing of later upgrades in the plan may be more flexible and the IRP model can evaluate earlier dates if they are feasible. Transmission upgrades options do not need to be part of PacifiCorp Transmission's long-term plan to be considered in the IRP.

The available options have been presented in the 2025 public input meeting series and will be presented in the filed 2025 IRP. In addition, each LT model's accompanying outcome file reports transmission options selected for the relevant portfolio, including the selected in-service year for the upgrade.

o What reliability and cost-benefit analysis does PAC Transmission conduct when determining which projects to move forward with?
 Is any of this information available to external IRP stakeholders interested in learning more?
o Is it correct to assume that none of the costs associated with these projects will be assigned to any of the candidate generator or storage objects defined in the PLEXOS IRP model?

**Reply:** Transmission upgrades that are required are typically not modeled in the PLEXOS model, as it would not impact the optimization. If later upgrades are contingent upon the required upgrade, its timing could impact the options that are modeled. If a required upgrade enables interconnection capability, the capability could be modeled at zero cost (or reduced cost if there are additional project-specific requirements).

Because the transmission options for both CON and INC provided for use in the PLEXOS model are generally derived from interconnection studies and not associated with transmission upgrades that are otherwise required to

* Required fields

meet NERC and WECC reliability standards and criteria, the cost-benefit and reliability analysis is conducted through the IRP models in deriving the least-cost, least-risk resource portfolio, balancing both cost and reliability.

• Is it correct to assume that PAC doesn't define a [Min Capacity Reserve Margin] requirement in PLEXOS for each TX region during the long-term (LT) portion of the model run?
o Similarly, is it correct to assume that PLEXOS' [Firm Capacity] property is also not defined, either for existing or candidate resources?
o I ask these questions because I am wondering if PacifiCorp allows for any capacity sharing across TX regions during a PLEXOS LT run.

**Reply**: Correct, the Min Capacity Reserve Margin and Firm Capacity properties are not defined in PLEXOS for the IRP. For the 2025 IRP, PacifiCorp is developing constraints that are similar to these properties to represent the Western Resource Adequacy Program (WRAP), including the associated planning reserve margin requirements and resource-specific qualifying capacity contribution values (QCCs). This was discussed at the June 26-27, 2024 public input meeting. PacifiCorp expects to comply with WRAP as a single system, but may need to account for limitations on transfers between the east and west side of its system. Capacity sharing within each side of the system is allowed implicitly.

Sample Use Cases
In this section I walk through are two examples to ensure I understand how PacifiCorp's IRP modeling team uses information from PAC's cluster studies to define eligible transmission system upgrades.
Sample Walk through Example #1
Table 1 lists the projects that were modeled in Cluster 2 – Cluster Area 13. Included in the table is a record of the projects that were studied in the initial cluster study and the first restudy . Table 2 provides a summary of the total amount of MWs evaluated in each cluster study, broken out by technology type.

Table 1: Candidate Projects from Cluster Study 2-Cluster Area 13

| Nov 2022 | Aug 2023 | Project | MW | Type | POI | COD | Requested Service |
|---|---|---|---|---|---|---|---|
| x | | C2-134 | 57.5 | Solar & Battery Storage | Clear Lake substation | 12/1/2026 | NR/ER |
| x | x | C2-179 | 40 | Geothermal | Black Rock substation | 12/31/2029 | ER |
| x | | C2-202 | 90 | Solar & Battery Storage | Pavant substation | 12/15/2026 | NR |
| x | | C2-211 | 49.9 | Solar & Battery Storage | Brush Wellington-Pavant transmission line | 2/11/2025 | NR/ER |

Table 2: Summary of Candidate Proejcts By Technology Type for Cluster Study 2-Cluster Area 13

| Cumulative Availability | Aug-22 Study | Nov-23 Study |
|---|---|---|
| Solar & Battery Storage | 197.4 | 0 |
| Geothermal | 40 | 40 |

Table 3 lists the project-specific and shared costs for TX work required for the successful interconnection of these projects onto PAC's system.
Table 3: TX-Related Expenses Assigned to Each Project for Cluster Study 2-Cluster Area 13

| Cost Category | Project | Nov 2022 Study ($k) | Aug 2023 Study ($k) |
|---|---|---|---|
| Interconnection Facilities | C2-134 | 1,390 | |
| Station Equipment | C2-134 | 5,700 | |
| Network Upgrades (ERIS) | C2-134 | 19,008 | |
| Total | C2-134 | 26,098 | |
| Interconnection Facilities | C2-179 | 750 | 750 |
| Station Equipment | C2-179 | 5,080 | 5,080 |
| Network Upgrades (ERIS) | C2-179 | 13,223 | 10,420 |
| Total | C2-179 | 19,053 | 16,250 |
| Interconnection Facilities | C2-202 | 1,600 | |
| Station Equipment | C2-202 | 10,500 | |

* Required fields

Network Upgrades (ERIS) C2-202 29,752
Total C2-202 41,852
Interconnection Facilities C2-211 1,310
Station Equipment C2-211 8,940
Network Upgrades (ERIS) C2-211 16,496
Total C2-211 26,746

Request for Confirmation:
• Were the PAC IRP team to represent Cluster Area 13 after the November 2022 study (but before the commencement of the August 2023 restudy), candidate generator and battery storage resources would be instantiated in the PLEXOS model for the Southern UT topology region.
o The TX region would encompass only two technology types: hybrid solar and geothermal projects.
o PLEXOS would allow for a maximum of 197.4 MW of hybrid solar-storage and 40 MW of geothermal capacity to be selected by the model, with project start dates defined by the respective CODs listed in Table 2.
o The PLEXOS model would also include constraints to account for applicable CON and INC TX network upgrade options required to interconnect these resources to PAC's system.
• Upon completion of the August 2023 restudy, the PLEXOS model would be modified to reflect only the option for 40 MW of new geothermal capacity located in the Southern Utah region.
o If PLEXOS opts for the full 40 MW of geothermal, it will also incur $16.25 million in transmission-related upgrade charges.
o Since PLEXOS models TX upgrade constraints as a continuous variable, the model can also opt for a portion of the generation (e.g., 20 MW) and incur a proportional share of the TX-related expense. In this case, $8.125 million.
o TX-related upgrade costs are annualized (i.e. $/kw-yr) prior to being entered into PLEXOS model. PacifiCorp assigns the appropriate financing assumptions to convert this overnight CAPX expense into an annuity calculation.
Questions Related to Cluster 2 Study Report: Cluster Area 13
• Upon completion of the November 2022 Cluster Study, is it correct to assume that if PLEXOS wants to select even 1 MW from any of the four project units listed in Table 1, a pro-rata share of all required network upgrades listed in the cluster study would also need to be completed?
o These pro-rata network upgrade costs would be in addition to any project-specific interconnection facilities and station equipment work that is also required, correct?
• In both the November 2022 study and the April 2023 study, it states, "No additional upgrades beyond those identified for ERIS are required for NRIS. All ERIS upgrades are required for NRIS." Based on this statement, is it correct to assume that the geothermal unit will automatically qualify as an NRIS-eligible facility by completing all of the ERIS-related TX upgrades?
• What is the source for the transmission projects listed as "assumed to be in service" for Cluster Area 13? Do they originate from PacifiCorp's long-term transmission plan? If so, are any costs associated with those projects assigned to the projects listed in Table 1?
• In the final Facilities Report for C2-179 , it is stated that the customer opted for ERIS service. How is this an available option if the network upgrades listed in the August 2023 restudy were already for ERIS interconnection service?

**Reply**: Because the IRP is intended to evaluate proxy resources, and not specific requests, it generally includes relatively little project-specific information and does not tie the results of a cluster study to individual requests in that study. The relevant transmission upgrade information used for modeling generally includes the following:

- IRP topology location
- Total amount of potential interconnection capability (in megawatts)
- Total transfer capability and point of delivery
- Total cost (for station equipment and network upgrades)
- First available in-service date
- Special considerations on available resource types. Solar and storage are generally available in most locations, and as they are inverter-based, have less complicated impacts on the transmission system. Geothermal and wind are generally only viable in a few locations. The presence of these resource types would indicate they are viable in that area, the absence of requests for those resource types in a given area could indicate they are not, or are at least less likely. There is flexibility in the interconnection process to modify the specific level of storage combined with solar, and surplus interconnection provides another means of creating hybrid resources. Given

that flexibility, PacifiCorp generally lets the model select any combination of available resources, so long as the actual generation remains within the interconnection limit in each hour.

Sample Walk through Example #2

Table 4 lists the projects that were modeled in Cluster 2 – Cluster Area 7 for each round. In the initial cluster study , 15 projects were evaluated, totaling 2,607 MW. In the first restudy , 6 projects—comprising 1,418 MW of generation and storage options—were studied. Finally, the second restudy  included 4 projects, totaling 1,098 MW.

Table 4:  Candidate Projects from Cluster Study 2-Cluster Area 7

| Nov 2022 | Aug 2023 | Apr 2024 | Project | MW | Type | POI | COD | Requested Service |
|---|---|---|---|---|---|---|---|---|
| | | | C2-30 | 199 | Solar & Battery Storage | Bridgerland substation | 12/31/2025 | NR/ER |
| x | x | x | C2-32 | 500 | Nuclear | Naughton substation | 11/1/2030 | NR |
| x | x | x | C2-48 | 48 | Natural Gas | Naughton substation | 5/18/2022 | ER |
| x | | | C2-55 | 150 | Battery Storage | Naughton-Treasureton transmission line | 10/31/2024 | NR |
| x | | | C2-63 | 220 | Wind | Railroad substation | 9/1/2026 | NR/ER |
| x | | | C2-77 | 100 | Solar & Battery Storage | Plymouth substation | 12/31/2027 | NR/ER |
| x | | | C2-84 | 150 | Solar & Battery Storage | Plymouth substation | 6/30/2025 | NR/ER |
| x | x | | C2-105 | 300 | Wind | Monument substation | 12/31/2025 | ER |
| x | x | x | C2-106 | 400 | Wind | Naughton-Ben Lomond #2 transmission line | 12/31/2025 | ER |
| x | | | C2-121 | 20 | Solar | Cutler-El Monte Willard Pump Tap transmission line | 12/1/2025 | ER |
| x | x | | C2-122 | 20 | Solar | Ben Lomond-Honeyville transmission line | 12/1/2025 | ER |
| x | | | C2-130 | 199 | Solar & Battery Storage | Plymouth substation | 12/1/2026 | NR/ER |
| x | | | C2-139 | 150 | Solar & Battery Storage | Blue Rim-South Trona transmission line | 12/1/2026 | NR/ER |
| x | | | C2-143 | 90 | Wind | Evanston-Anschutz transmission line | 12/31/2026 | NR/ER |
| x | | | C2-155 | 110 | Solar & Battery Storage | Muddy Creek substation | 12/31/2026 | NR/ER |
| x | x | x | C2-205 | 150 | Solar & Battery Storage | Bridgerland-Cache transmission line | 10/31/2026 | ER |

Table 5 provides a summary of the projects studied in the second restudy, broken down by technology type, while Table 6 lists the corresponding network upgrades—both ERIS- and NRIS-related—required for those projects to interconnect with PAC's bulk TX system.

Table 5: Summary of Proejcts from Cluster Study 2-Cluster Area 7 (Apr 2024 Restudy)

| Cumulative Availability | MW |
|---|---|
| Solar & Battery Storage | 150 |
| Nuclear | 500 |
| Natural Gas | 48 |
| Battery Storage | 0 |
| Wind | 400 |
| Solar | 0 |

Table 6: Shared Transmission Network Upgrades Costs ($k) for Cluster Study 2-Cluster Area 7 (Apr 2024 Restudy)

| Type | Location | Project | Apr 2024 Study ($k) |
|---|---|---|---|
| ERIS | Naughton substation | Install new 230 kV breaker | 1,500 |
| ERIS | Naughton – Ben Lomond 345kV TX line | New approx. 88 miles of 230 kV TX line | 349,500 |
| ERIS | Ben Lomond substation | Seven (7) 230 kV breaker replacements | 4,300 |
| ERIS | Plain City substation | breaker replacement | 500 |
| NRIS | Jim Bridger substation | 345/230kV 700MVA transformer | 16,100 |
| NRIS | Ben Lomond - Plain City | Rebuild approx. 2 miles of 138kV TX line | 3,800 |
| NRIS | Ben Lomand substation | Replace Ben Lomond-Plain City relay | 300 |
| NRIS | Plain City substation | Replace Ben Lomond-Plain City relay | 300 |
| NRIS | Ben Lomond - Cold Water | Rebuild approx. 9 miles of 138kV TX line | 14,400 |
| NRIS | Plain City to West Ogden North Tap | Rebuild approx. 6.5 miles of 138kV TX line | 8,600 |

* Required fields

| | | | |
|---|---|---|---|
| NRIS | West Ogden North Tap to Midland West Tap | Rebuild approx. 2.5 miles of 138kV TX line | 4,000 |
| NRIS | Warren to West Ogden South Tap | Rebuild approx. 6.5 miles of 138kV TX line | 8,500 |
| NRIS | West Ogden South Tap to Midland East Tap | Rebuild approx. 2.5 miles of 138kV TX line | 4,000 |
| NRIS | Midland East Tap to Clinton East Tap | Rebuild approx. 5.5 miles of 138kV TX line | 7,800 |
| NRIS | Clinton East Tap to Syracuse | Rebuild approx. 3.5 miles of 138kV TX line | 4,600 |
| NRIS | Cold Water - El Montel | Rebuild approx. 5.5 miles of 138kV TX line | 7,200 |
| NRIS | Ben Lomond - Warren | Rebuild approx. 5 miles of 138kV TX line | 6,900 |
| NRIS | Ben Lomond - Birch Creek and Ben Lomond - Naughton | Rebuild approx. 8 miles of 230kV TX line sections | 42,900 |
| NRIS | Naughton substation | RAS work | 300 |
| | ERIS Network Upgrades (subtotal) | 355,800 | |
| | NRIS Network Upgrades (subtotal) | 129,700 | |
| | Network Upgrades (total) | 485,500 | |

Table 7 lists the project-specific and shared network upgrade costs for project C2-106, which is the construction of a 400 MW wind facility at a new substation located off the Ben Lomond-Naughton #2 transmission line. The $198.1k listed for network upgrade costs in the Apr 2024 Study represents C2-106's proportional share of the shared costs listed in Table 6. The pro-rata allocation of these shared expenses is based on the POI nameplate capacity for all projects listed as active in the April study.

Table 7: Project-Specific and Shared Transmission Network Upgrade Costs ($k) for Project C2-106.

| Cost Type | Project | Nov 2022 Study | Aug 2023 Study | Apr 2024 Study |
|---|---|---|---|---|
| Interconnection Facilities: Collector | C2-106 | 800 | 800 | 1,300 |
| Interconnection Facilities: POI | C2-106 | 1,600 | 1,600 | 1,300 |
| Station Equipment | C2-106 | 8,200 | 8,200 | 12,700 |
| Network Upgrades (ERIS) | C2-106 | 122,131 | 110,141 | 150,893 |
| Network Upgrades (NRIS) | C2-106 | 64,420 | 126,082 | 47,250 |
| Network Upgrades (subtotal) | C2-106 | 186,552 | 236,223 | 198,142 |
| Total | | 197,152 | 246,823 | 213,442 |

Questions Related to Cluster 2 Study Report: Cluster Area 7

- How does the PAC IRP team configure shared network upgrade costs across multiple projects in their PLEXOS model?
  - Will the model have to absorb the entire costs of the projects listed in Table 6 before a MW from any of the technology options listed in Table 5 can be added to PAC's system, or is there a proportional TX-related charge that gets applied based on how much generation PLEXOS wants to add in this TX region?
- According to queue information posted by PAC Transmission, project C2-106 requested ER interconnection service. Consequently, will the PAC IRP model reflect both ERIS- and NRIS-eligible wind resource options in the Wyoming region?
  - If so, will the ERIS-eligible wind resource exclude the NRIS-related TX network upgrade expenses?
- In the August 2023 restudy, the Naughton–Ben Lomond 345 kV transmission line is listed in both the ERIS section (Section 9) and the NRIS section (Section 13). Is this an error, or is it correct?
  - If correct, what are the grounds for a TX project to be listed as both an ERIS- and NRIS-related upgrade?
- How are TX expenses related to contingent facilities handled by PAC's IRP team?
  - Are any of these costs—triggered by cluster studies from previous years—assigned to the projects listed in Table 4?
  - Is all the TX work required to resolve these contingent facilities approved and assumed to be in place by a certain date within the model?
  - Conversely, if the TX work to resolve the contingent facilities is still under consideration by PAC TX, are there sequential INC and CON TX constraints that PLEXOS must navigate to access the generation and storage options listed in Table 4?

**Reply:** IRP modeling does not differentiate the costs specific to individual cluster requests - the total cost and total interconnection are modeled. Initial modeling allows this total to be considered on a linear basis. To the extent an integer determination (i.e. all of a particular upgrade or nothing) is needed in the final result, additional analysis would be performed.

With regard to contingent facilities, each of the successive upgrade options in a given location are assumed to be contingent on the prior upgrades unless they are known to be distinct. When upgrades are contingent on upgrades in other locations, constraints are used to ensure prior requirements are met. The modeled costs of all transmission network upgrades reflect PacifiCorp Energy Supply Management's share of the overall PacifiCorp Transmission customer base, which is around 80%, with PacifiCorp Transmission's other customers contributing the remainder. This is true for all network upgrades, whether triggered by reliability requirements, PacifiCorp Energy Supply Management requests, or those of other customers of PacifiCorp Transmission. Costs are generally not modeled for transmission upgrades that are required (not optional), as the cost would appear in every result and would not have any bearing on the optimization.

Questions Related to Surplus Interconnection

- Is there any significance associated with ERIS/NRIS designations in surplus interconnection studies?
  - For example, is the surplus option configured differently if it's modeled at a location with existing ERIS compared to a facility qualified for NRIS?

**Reply:** ERIS/NRIS has no bearing on surplus interconnection studies and is not modeled differently.

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**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.

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**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.

**PacifiCorp Response:**
Thank you for the feedback. As discussed in the in-line responses throughout your request, the modeling in the IRP has significant simplifications relative to cluster study results and process.

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Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com

Thank you for participating.

* Required fields

# PacifiCorp - Stakeholder Feedback Form (041)

Integrated Resource Plan

PacifiCorp (the Company) requests that stakeholders provide feedback to the Company upon the conclusion of each public input meeting and/or stakeholder conference call, as scheduled. PacifiCorp values the input of its active and engaged stakeholder group, and stakeholder feedback is critical to the IRP public input process. PacifiCorp requests that stakeholders provide comments using this form, which will allow the Company to more easily review and summarize comments by topic and to readily identify specific recommendations, if any, being provided. Information collected will be used to better inform issues included in the IRP, including, but not limited to the process, assumptions, and analysis. In order to maintain open communication and provide the broader Stakeholder community with useful information, the Company will post appropriate feedback on the IRP website based on your selection below.

Date of Submittal 2024-09-20


*Name: Nathan Strain
Title:
*E-mail: nathanv.strain@gmail.com
Phone: (435) 200 - 5963
*Organization: Citizen
Address: 259 East 4800 South Apt. 4
City: Murray State: UT Zip: 84107


Public Meeting Date comments address: 08-15-2024 ☒ Check here if related to specific meeting

List additional organization attendees at cited meeting:

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.
Existing Thermal Resource Options

☒ Check here if you want your Stakeholder feedback and accompanying materials posted to the IRP website.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.
With the volatility of coal supply and the environmental concerns associated with coal has Pacificorp placed a heightened interest in conventional Nuclear? I am aware that suel for SMRs is more scarce and expensive, perhaps a large conventional Nuclear plant at the site of the Hunter Power Plant or a purchase of the stalled Blue Castle Nuclear Project is warranted. Construction of conventional nuclear in Utah is likely to be politically and socially popular. Pacificorp should also accelerate development of Geothermal in Utah.

**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.

**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.
Explore a large conventional Nuclear plant in Utah at the site of Hunter Plant or the Blue Castle Project. More aggressively pursue geothermal.

**PacifiCorp Response:**
PacifiCorp's supply-side resource table for the 2025 IRP includes nuclear and geothermal resource options and was recently posted to the Company's website:
https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2025-irp/2025-irp-support-studies/Public_SSR_Database_Summary_Tab_2025.xlsx

* Required fields

The IRP generally does not evaluate specific projects but can identify general locations that might be favorable for different resource types. PacifiCorp would note that the inclusion or exclusion of different resource types in the preferred portfolio is an indication of the relative performance based on the supply-side resource assumptions. PacifiCorp is also planning to prepare sensitivity studies based on "advanced" nuclear and geothermal costs, which start lower than the baseline cost forecast and decline faster through time. The decision to move forward with particular resource offerings is based on bids for specific projects, which can vary widely, along with consideration of a variety of less tangible risks related to both the existing resource mix and potential resource additions.

Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com

Thank you for participating.

* Required fields

# PacifiCorp - Stakeholder Feedback Form (042)

## Integrated Resource Plan

PacifiCorp (the Company) requests that stakeholders provide feedback to the Company upon the conclusion of each public input meeting and/or stakeholder conference call, as scheduled. PacifiCorp values the input of its active and engaged stakeholder group, and stakeholder feedback is critical to the IRP public input process. PacifiCorp requests that stakeholders provide comments using this form, which will allow the Company to more easily review and summarize comments by topic and to readily identify specific recommendations, if any, being provided. Information collected will be used to better inform issues included in the IRP, including, but not limited to the process, assumptions, and analysis. In order to maintain open communication and provide the broader Stakeholder community with useful information, the Company will post appropriate feedback on the IRP website based on your selection below.

Date of Submittal 2024-09-23

*Name: Jim Himelic  Title:

*E-mail: jhimelic@firstprinciples.run  Phone: 5209791375

*Organization: First Principles Advisory

Address:

City:  State:  Zip:

Public Meeting Date comments address:  ☐ Check here if related to specific meeting

List additional organization attendees at cited meeting:

---

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.
PLEXOS LT Settings

---

☒ Check here if you want your Stakeholder feedback and accompanying materials posted to the IRP website.

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***Respondent Comment:** Please provide your feedback for each IRP topic listed above.
Please provide a copy of the LT Plan settings used by PacifiCorp for their all final capacity expansion modeling optimization runs conducted in PLEXOS. Please include in that discussion the application of any global variables and/or undocumented parameters such as slicing blocks, sampling years, and mixed chronology timestep blocks.

---

**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.

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**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.
I originally submitted this form back in May of this year but I never received a response. Resubmitting it here again. Please confirm receipt

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**PacifiCorp Response:**
We are currently working on inputting data for 2025 IRP and are also testing performance and various LT Plan settings. We do not expect the settings to be settled until later in the process, and they are subject to further changes post-draft. These settings will be provided as part of the data disc for the 2025 IRP.

Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com

Thank you for participating.

* Required fields

# PacifiCorp - Stakeholder Feedback Form (044)

## Integrated Resource Plan

PacifiCorp (the Company) requests that stakeholders provide feedback to the Company upon the conclusion of each public input meeting and/or stakeholder conference call, as scheduled. PacifiCorp values the input of its active and engaged stakeholder group, and stakeholder feedback is critical to the IRP public input process. PacifiCorp requests that stakeholders provide comments using this form, which will allow the Company to more easily review and summarize comments by topic and to readily identify specific recommendations, if any, being provided. Information collected will be used to better inform issues included in the IRP, including, but not limited to the process, assumptions, and analysis. In order to maintain open communication and provide the broader Stakeholder community with useful information, the Company will post appropriate feedback on the IRP website based on your selection below.

Date of Submittal 2024-09-28

*Name: Rose Monahan Title:
*E-mail: rose.monahan@sierraclub.org Phone: (415) 977 - 5704
*Organization: Sierra Club
Address: 2101 Webster Street, Suite 1300
City: Oakland State: CA Zip: 94612
Public Meeting Date comments address: 09-25-2024 ☒ Check here if related to specific meeting
List additional organization attendees at cited meeting:

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.
Thermal Resource Options

☒ Check here if you want your Stakeholder feedback and accompanying materials posted to the IRP website.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.
At the September 2024 PIM, PacifiCorp explained that CCUS will be considered for coal units, including the Hunter and Huntington units, and that the CCUS option includes SCR installation. Moreover, if the model selects CCUS at a single coal plant unit, CCUS must be selected for all of the other coal units at that plant. Sierra Club urges PacifiCorp to modify these assumptions as explained below.  First, PacifiCorp should consider SCR as a standalone requirement, and, as recommended by Sierra Club in its previous stakeholder feedback form, include a modeling constraint that requires SCR at least one Hunter unit and both Huntington units by no later than 2028. By including SCR within the CCUS option, PacifiCorp is ignoring the possibility that SCR could be mandated at its coal units, particularly the Hunter and Huntington plants, before CCS is required or could be mandated even if the CCS requirement is not implemented. SCR is likely to be required at the Hunter and Huntington coal plants under the Clean Air Act\u0019s Regional Haze Program. Indeed, in proposing to disapprove Utah\u0019s regional haze state implementation plan for the second implementation period, EPA faulted Utah for failing to require SCR at Hunter Unit 3 and further stated that SCR likely should have been required at the other Hunter and Huntington coal units. The current regional haze planning period runs through 2028. As a result, it\u0019s likely that should SCR be required at the Hunter and Huntington units, installation will be required before 2030, when PLEXOS assumes CCUS becomes available. Moreover, the likely SCR requirement at the Utah coal plants is separate from the CCS obligation under EPA\u0019s recent 111(d) regulation for coal plants that continue operating past 2035. While Sierra Club believes that the 111(d) regulation will be implemented, as PacifiCorp is well aware, environmental regulations can be stayed, remanded to the agency, and/or vacated. If any of these options occur for the 111(d) regulation but not EPA\u0019s regional haze regulations for Utah, then the CCS obligation may not apply while the SCR obligation does. By conflating these two separate requirements in the PLEXOS modeling, PacifiCorp will be failing to clearly evaluate the

* Required fields

least-cost approach to complying with both regulations. Second, PacifiCorp should change the CCUS option in PLEXOS to CCS. The CCUS option is presumably meant to comply with EPA\u0019s 111(d) regulation, but that regulation does not authorize coal units to utilize carbon capture, utilization, and sequestration technology. Instead, coal units must install carbon capture and sequestration technology, otherwise the coal units are not reducing their CO2 emissions but shifting them to a secondary purpose. There is no reason to model a regulatory compliance obligation in a way that does not actually comply with that regulation. Finally, PacifiCorp should remove the requirement that if the PLEXOS model selects CCS at any one unit of a coal plant, that the model must select CCS at all the plant\u0019s units. At the public input meeting, PacifiCorp asserted that this constraint was reasonable because it is more cost effective to install CCS across an entire plant rather than a single unit. While Sierra Club understands economies of scale, it is not clear why PLEXOS cannot incorporate pricing assumptions that assume lower costs for a second (or third) CCS installation at the same plant, rather than forcing the model to select CCS for all units. Adjusting pricing assumptions for additional CCS installations would allow PLEXOS to determine whether economies of scale warrant adding CCS to additional units, rather than PacifiCorp making this assumption for the model ahead of time. Not only does the constraint significantly skew the models internal logic, but Sierra Club is also concerned that this constraint could result in PLEXOS running entire coal plants longer than necessary to meet reliability requirements when those reliability requirements could have been met with less than the entire coal plant\u0019s output. For example, if the PLEXOS model finds that, in order to maintain reliability, the PacifiCorp system requires continued operation of one Hunter unit, PacifiCorp\u0019s proposed modeling constraint could force PLEXOS to select continued operation at all three of the Hunter units, even though reliability would have been met with just one unit. This is very likely to artificially keep coal plants operating\u0014with highly expensive CCS and SCR controls\u0014when lower cost and more efficient options are available. Indeed, it would skew the model to support high cost investments (for which PacifiCorp earns a rate of return) over more cost effective options. This could be a major liability in securing acknowledgment of the 2025 IRP before state public utility commissions, not to mention achieving cost recovery in future rate cases.

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**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.

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**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.
1. PacifiCorp should consider SCR as a standalone requirement, and, as recommended by Sierra Club in its previous stakeholder feedback form, include a modeling constraint that requires SCR at least one Hunter unit and both Huntington units by no later than 2028.

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**PacifiCorp Response:**

Thank you very much for your feedback. The coal plant scenarios provided to the IRP team include continued operations as currently configured, Gas Conversion and CCUS with SCR. The Company has SCR costs for each unit and estimated emissions reductions that would result from SCR installation, such that the cost of the emissions reductions that would result from an SCR can be calculated for any study result. The Company does not have information that would suggest that SCR on its own would impact the operating characteristics of a unit, such as the heat rate, maximum operating level, and so forth, so the inclusion of SCR is unlikely to change the way plants operate under current rules. Should rules change in the future, PacifiCorp will work to identify the least cost, least risk pathway to compliance, which may include SCR, placing limits on generation, replacing units or retrofitting units to burn other fuel types in some or any combination of actions.

Regarding the concern related to requiring CCUS installation at all locations if the model would like to select CCUS at one, in practice, PacifiCorp would not undergo the significant capital costs to install CCUS for a single unit when all units at a site could leverage the technology for a nominal added cost. Regarding CCUS vs. CCS, PacifiCorp has called these projects CCUS, but essentially is only modeling the Carbon Capture (or CC) side. Additionally, PacifiCorp is applying the largest eligible tax credit for a CCUS/CCS project. In order to maximize benefits (or reduce costs for customers), PacifiCorp would certainly need to evaluate actual proposals knowing which level of tax credit would apply based on the final CO2 use. While it may be of interest to see whether or not the model would select a single unit for CCUS conversion or a final CO2 use that garnered lower tax credits, real world implementation of these options is implausible. Given ongoing requests that PacifiCorp model actions which are as close to reality as possible (given the imperfect nature of future proxy costs and performance) asking PacifiCorp to evaluate a choice it simply would not make is unnecessary.

Additionally, any selection of any change to an existing plant within the IRP will be subject to further consideration and evaluations. In particular, selection of proxy CCUS costs and performance, or other high cost equipment such as an SCR would be reviewed and validated using actual proposals from developers as part of the proposal, permitting and approval process. In the absence of specific proposals with cost and performance that are projected to be a benefit to customers, the project would not move forward.

PacifiCorp will consider calculating the cost of emissions reductions from an SCR within the constraints of 2025 IRP timelines and requirements.

Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com

Thank you for participating.

* Required fields

# PacifiCorp - Stakeholder Feedback Form (045)

## Integrated Resource Plan

PacifiCorp (the Company) requests that stakeholders provide feedback to the Company upon the conclusion of each public input meeting and/or stakeholder conference call, as scheduled. PacifiCorp values the input of its active and engaged stakeholder group, and stakeholder feedback is critical to the IRP public input process. PacifiCorp requests that stakeholders provide comments using this form, which will allow the Company to more easily review and summarize comments by topic and to readily identify specific recommendations, if any, being provided. Information collected will be used to better inform issues included in the IRP, including, but not limited to the process, assumptions, and analysis. In order to maintain open communication and provide the broader Stakeholder community with useful information, the Company will post appropriate feedback on the IRP website based on your selection below.

Date of Submittal 2024-11-18


*Name: Kevin Emerson Title: Director of Building Efficienc

*E-mail: irp@pacificorp.com Phone: (801) 608 - 0850

*Organization: Utah Clean Energy

Address: 215 S. 400 E.

City: Salt Lake City State: UT Zip: 84129


Public Meeting Date comments address: 09-25-2024 ☒ Check here if related to specific meeting

List additional organization attendees at cited meeting:

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.
Baseline building energy code assumptions in the 2025 IRP Conservation Potential Assessment

☒ Check here if you want your Stakeholder feedback and accompanying materials posted to the IRP website.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.
According to the presentation slides used at the 2025 Integrated Resource Planning Public Input Meeting on September 25, 2024, AEG is using an inaccurate code baseline for residential new construction in Utah. Slide 14 indicates that AEG is using the \u001C2015 IECC\u001D as representing Utah\u0019s energy code baseline for residential construction in the state (see Note 1). While Utah\u0019s residential energy code was updated by the Utah Legislature in March 2024 (see Note 2), the legislation maintained the numerous weakening amendments in Utah\u0019s residential energy code, which has been previously recognized as equivalent to the 2009 IECC. As per U.S. Department of Energy\u0019s Status of Energy Code Adoption map, despite the 2024 legislation, Utah\u0019s residential energy code is still recognized as equivalent to the 2009 IECC (see Note 3). The U.S. Department of Energy estimates that Utah\u0019s residential energy code is 29% less efficient than the 2021 IECC, the most recent model energy code. Using the correct residential energy code baseline will impact the cost-effectiveness of new homes programs and more accurately reflect the potential energy savings achievable though Rocky Mountain Power\u0019s New Homes rebate program.

**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.

**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.
AEG\u0019s Conservation Potential Assessment modeling processes should be adjusted to reflect the 2009 IECC as Utah\u0019s baseline residential energy code to capture the

* Required fields

realistic level of energy saving potential associated with utility-sponsored new homes rebate programs.

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Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com

Thank you for participating.

**PacifiCorp Response:**

Thank you for providing the information. Applied Energy Group (AEG) reviewed the US Department of Energy webpage that Utah Clean Energy provided during the September 2024 Public Input Meeting, as well as text from Utah's House Bill 0518, passed in March 2024. AEG verified that the building envelope parameters now being used in the CPA are "consistent with the latest Utah code *plus amendments*."

AEG noted that they primarily lean on the insulation and fenestration requirements in the component tables and other key parameters such as duct insulation/air leakage requirements for residential measures. The commercial codes tend to have much more complicated rules regarding controls and measure eligibility in new construction but were also verified against the latest Utah code plus amendments.

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# **PacifiCorp - Stakeholder Feedback Form** (046)

## Integrated Resource Plan

PacifiCorp (the Company) requests that stakeholders provide feedback to the Company upon the conclusion of each public input meeting and/or stakeholder conference call, as scheduled. PacifiCorp values the input of its active and engaged stakeholder group, and stakeholder feedback is critical to the IRP public input process. PacifiCorp requests that stakeholders provide comments using this form, which will allow the Company to more easily review and summarize comments by topic and to readily identify specific recommendations, if any, being provided. Information collected will be used to better inform issues included in the IRP, including, but not limited to the process, assumptions, and analysis. In order to maintain open communication and provide the broader Stakeholder community with useful information, the Company will post appropriate feedback on the IRP website based on your selection below.

Date of Submittal 2024-11-18

*Name: Kevin Emerson
Title: Director of Building Efficienc
*E-mail: irp@pacificorp.com
Phone: (801) 608 - 0850
*Organization: Utah Clean Energy
Address: 215 S. 400 E.
City: Salt Lake City State: UT Zip: 84129

Public Meeting Date comments address: ☐ Check here if related to specific meeting

List additional organization attendees at cited meeting:

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.
Updated Energy Efficiency and Demand Response Data Broken Out by State

☒ Check here if you want your Stakeholder feedback and accompanying materials posted to the IRP website.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.
Please provide state-by-state data represented in Figure 1.11 \u0013 2023 IRP Update Preferred Portfolio Energy Efficiency and Demand Response Capacity, which can be found on page 10 of the 2023 Integrated Resource Plan Update. Specifically, we request to see state-by-state data as presented in two tables from the 2023 Integrated Resource Plan Volume II Appendices, Tables D.3 and D.4 (page 108).

**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.

**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.

**PacifiCorp Response:**
Thank you for the data request.

Note that Tables D.3 and D.4 from the 2023 IRP Appendix D show *first-year incremental* resource selections in units of MWh for energy efficiency (EE) and MW for demand response (DR). Meanwhile, Figure 1.11 in the 2023 IRP Update report shows *cumulative* capacity in units of MW for both EE and DR.

| **Resource** | **Incremental Selections** | **Cumulative Capacity** |
|---|---|---|

* Required fields

| | | |
|---|---|---|
| Demand Response | Table D.3 (in MW) | Figure 1.11 (in MW) |
| Energy Efficiency | Table D.4 (in MWh) | Figure 1.11 (in MW) |

As such, PacifiCorp is presenting all four combinations of these figures, using the 2023 IRP Update data at the state level:

1) DR — First-Year Incremental (MW), like Table D.3
2) DR — Cumulative (MW), like Figure 1.11
3) EE — First-Year Incremental (MWh), like Table D.4
4) EE — Cumulative (MW), like Figure 1.11

* Required fields

1) DR — First-Year Incremental (MW), like Table D.3

This figure does not include existing or planned DR resources, rather exclusively shows the new, incremental DR resource selections in each year from the 2023 IRP Update. It also provides summer and winter DR capacity split-out. The figure is not cumulative.

**Table D.3 –First Year Demand Response Resource Selections (2023 IRP Update)**
(Units in MW)

| Resource | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|---|---|---|---|---|---|
| DR Summer - ID | 0.0 | 0.0 | 1.0 | 8.6 | 0.4 | 4.0 | 0.3 | 0.0 | 0.6 | 9.2 |
| DR Summer - UT | 0.0 | 8.5 | 17.1 | 15.4 | 9.2 | 24.6 | 12.2 | 0.0 | 24.4 | 12.5 |
| DR Summer - WY | 0.0 | 0.0 | 10.5 | 1.6 | 0.6 | 27.1 | 0.5 | 0.0 | 0.9 | 0.3 |
| DR Winter - ID | 0.0 | 0.4 | 1.2 | 1.5 | 0.9 | 0.5 | 0.3 | 0.3 | 0.2 | 0.2 |
| DR Winter - UT | 0.0 | 0.0 | 11.1 | 13.7 | 8.4 | 7.8 | 6.0 | 6.5 | 4.9 | 4.9 |
| DR Winter - WY | 0.0 | 0.0 | 9.4 | 13.6 | 0.7 | 9.8 | 0.4 | 0.4 | 0.3 | 0.6 |
| DR Summer - CA | 0.0 | 0.0 | 1.5 | 1.2 | 0.5 | 1.7 | 0.1 | 0.0 | 0.3 | 0.1 |
| DR Summer - OR | 0.0 | 1.9 | 21.6 | 25.4 | 6.0 | 34.3 | 36.4 | 0.0 | 19.1 | 4.2 |
| DR Summer - WA | 0.0 | 2.8 | 4.7 | 7.5 | 1.1 | 15.0 | 0.9 | 0.0 | 4.8 | 0.6 |
| DR Winter - CA | 0.0 | 0.0 | 1.2 | 0.6 | 0.2 | 0.2 | 0.1 | 0.1 | 0.0 | 0.4 |
| DR Winter - OR | 0.0 | 14.7 | 11.9 | 19.3 | 6.0 | 7.4 | 3.1 | 3.4 | 0.0 | 52.8 |
| DR Winter - WA | 0.0 | 9.7 | 6.8 | 1.3 | 1.0 | 0.8 | 0.6 | 0.7 | 0.0 | 26.2 |

| Resource | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 |
|---|---|---|---|---|---|---|---|---|---|---|
| DR Summer - ID | 0.0 | 0.2 | 0.1 | 0.2 | 20.9 | 11.1 | 0.0 | 0.7 | 0.6 | 0.0 |
| DR Summer - UT | 0.0 | 21.1 | 10.0 | 10.5 | 10.9 | 53.9 | 0.0 | 30.3 | 84.4 | 0.0 |
| DR Summer - WY | 0.0 | 0.3 | 0.0 | 0.0 | 0.0 | 9.9 | 0.0 | 0.2 | 0.5 | 0.0 |
| DR Winter - ID | 0.1 | 0.4 | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| DR Winter - UT | 2.5 | 0.6 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| DR Winter - WY | 0.2 | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.5 |
| DR Summer - CA | 0.0 | 0.1 | 0.0 | 0.0 | 0.1 | 4.1 | 0.0 | 1.0 | 0.1 | 0.0 |
| DR Summer - OR | 0.0 | 16.5 | 0.3 | 0.3 | 11.1 | 22.0 | 0.0 | 37.3 | 6.5 | 0.0 |
| DR Summer - WA | 2.6 | 0.2 | 2.0 | 0.8 | 0.0 | 6.6 | 0.1 | 1.2 | 2.8 | 2.6 |
| DR Winter - CA | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| DR Winter - OR | 1.2 | 0.4 | 0.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| DR Winter - WA | 2.2 | 1.8 | 1.3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.0 | 0.0 |

* Required fields

2) DR — Cumulative (MW), like Figure 1.11

Different from Table D.3 above, this Figure 1.11 table shows *cumulative* DR capacity. It also sums the summer and winter values to show a single state-wide capacity value. The figure does not include prior existing or planned DR resources.

**Figure 1.11 - Cumulative Demand Response Resource Selections (2023 IRP Update)**
(Sum of Summer & Winter; Units in MW)

| Resource | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|---|---|---|---|---|---|
| DR - Idaho | 0.0 | 0.4 | 2.6 | 12.8 | 14.1 | 18.6 | 19.2 | 19.5 | 20.4 | 29.7 |
| DR - Utah | 0.0 | 8.5 | 36.7 | 65.8 | 83.4 | 115.8 | 133.9 | 140.5 | 169.8 | 187.2 |
| DR - Wyoming | 0.0 | 0.0 | 19.9 | 35.1 | 36.3 | 73.3 | 74.2 | 74.6 | 75.7 | 76.6 |
| DR - California | 0.0 | 0.0 | 2.7 | 4.5 | 5.1 | 7.0 | 7.2 | 7.3 | 7.6 | 8.1 |
| DR - Oregon | 0.0 | 16.5 | 50.1 | 94.7 | 106.7 | 148.3 | 187.9 | 191.3 | 210.4 | 267.4 |
| DR - Washington | 0.0 | 12.5 | 24.0 | 32.8 | 35.0 | 50.8 | 52.3 | 53.0 | 57.8 | 84.6 |

| Resource | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 |
|---|---|---|---|---|---|---|---|---|---|---|
| DR - Idaho | 29.8 | 30.5 | 30.7 | 31.0 | 51.9 | 63.0 | 63.0 | 63.7 | 64.3 | 64.3 |
| DR - Utah | 189.6 | 211.3 | 221.2 | 231.7 | 242.6 | 296.5 | 296.5 | 326.8 | 411.2 | 411.2 |
| DR - Wyoming | 76.7 | 77.2 | 77.2 | 77.3 | 77.3 | 87.2 | 87.2 | 87.4 | 88.0 | 88.5 |
| DR - California | 8.1 | 8.3 | 8.4 | 8.4 | 8.5 | 12.7 | 12.7 | 13.7 | 13.8 | 13.8 |
| DR - Oregon | 268.6 | 285.5 | 286.0 | 286.3 | 297.4 | 319.4 | 319.4 | 356.7 | 363.2 | 363.2 |
| DR - Washington | 89.4 | 91.3 | 94.7 | 95.6 | 95.6 | 102.2 | 102.3 | 103.6 | 106.3 | 109.0 |

* Required fields

3) EE — First Year Incremental (MWh), like Table D.4

This table shows EE savings selected in each year on a new, incremental, and first-year savings basis, in units of MWh. It is not cumulative and does not include existing or planned EE resources. Savings from Home Energy Reports are excluded as well.

**Table D.4 – First-Year Energy Efficiency Resource Selections (2023 IRP Update)**
(Excludes Home Energy Report Savings; Units in MWh)

| State | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|---|---|---|---|---|---|
| EE - California | 2,426 | 1,447 | 3,309 | 4,219 | 4,302 | 4,949 | 5,455 | 5,152 | 6,837 | 6,559 |
| EE - Oregon | 180,799 | 166,678 | 179,988 | 163,586 | 166,963 | 166,894 | 161,227 | 158,138 | 164,427 | 141,902 |
| EE - WA | 53,111 | 47,873 | 50,093 | 32,864 | 37,299 | 42,772 | 45,988 | 48,803 | 51,944 | 52,661 |
| EE - Utah | 266,501 | 267,939 | 272,287 | 328,565 | 376,872 | 418,663 | 447,683 | 461,195 | 479,295 | 490,851 |
| EE - Idaho | 11,998 | 14,924 | 17,533 | 23,331 | 25,929 | 29,383 | 31,060 | 31,616 | 33,629 | 34,674 |
| EE - Wyoming | 44,205 | 41,231 | 41,271 | 60,911 | 65,767 | 74,468 | 73,294 | 78,878 | 80,477 | 83,545 |
| Total System | 559,041 | 540,092 | 564,481 | 613,476 | 677,133 | 737,129 | 764,707 | 783,782 | 816,608 | 810,193 |

| State | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 |
|---|---|---|---|---|---|---|---|---|---|---|
| EE - California | 6,313 | 6,068 | 4,840 | 5,899 | 6,455 | 4,929 | 4,416 | 4,180 | 3,782 | 2,889 |
| EE - Oregon | 129,397 | 128,891 | 124,318 | 119,729 | 116,967 | 94,132 | 93,169 | 107,376 | 81,309 | 97,751 |
| EE - WA | 48,740 | 46,200 | 41,550 | 40,853 | 35,002 | 31,963 | 28,115 | 27,882 | 24,825 | 23,594 |
| EE - Utah | 479,885 | 484,728 | 487,804 | 507,404 | 476,815 | 457,433 | 425,194 | 489,622 | 417,013 | 408,578 |
| EE - Idaho | 32,998 | 32,356 | 31,510 | 31,920 | 28,194 | 27,623 | 24,819 | 26,121 | 22,179 | 20,757 |
| EE - Wyoming | 79,290 | 78,293 | 73,052 | 72,758 | 63,554 | 61,514 | 57,448 | 63,129 | 48,250 | 51,786 |
| Total System | 776,623 | 776,535 | 763,075 | 778,562 | 726,987 | 677,594 | 633,161 | 718,310 | 597,357 | 605,354 |

* Required fields

4) EE — Cumulative (MW), like Figure 1.11

In alignment with Figure 1.11, this table shows *capacity* from EE resources, in units of MW, as opposed to energy savings in MWh. It is shown in *cumulative* capacity and also does not include capacity from Home Energy Reports. The figure does not include prior existing or planned EE resources.

**Figure 1.11 - Cumulative Energy Efficiency Resource Selections (2023 IRP Update)**
(Excludes Home Energy Report Savings; Units in MW)

| State | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|---|---|---|---|---|---|
| EE - California | 1.0 | 1.6 | 3.0 | 4.0 | 4.9 | 6.0 | 7.1 | 8.3 | 10.3 | 11.7 |
| EE - Oregon | 56.6 | 102.8 | 166.7 | 223.4 | 277.8 | 332.5 | 397.2 | 456.5 | 546.8 | 579.3 |
| EE - Washington | 16.6 | 31.4 | 47.9 | 54.0 | 61.0 | 69.2 | 78.3 | 88.1 | 97.8 | 108.7 |
| EE - Utah | 78.6 | 155.2 | 266.9 | 344.9 | 437.2 | 542.3 | 662.9 | 791.6 | 915.8 | 1,040.3 |
| EE - Idaho | 2.9 | 6.4 | 10.7 | 17.4 | 24.7 | 32.8 | 41.5 | 50.6 | 59.1 | 68.2 |
| EE - Wyoming | 9.6 | 18.9 | 32.1 | 43.9 | 56.7 | 71.3 | 85.4 | 100.7 | 114.9 | 131.4 |
| Total System | 165.3 | 316.3 | 527.3 | 687.6 | 862.4 | 1,054.1 | 1,272.5 | 1,495.8 | 1,744.7 | 1,939.6 |

| State | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 |
|---|---|---|---|---|---|---|---|---|---|---|
| EE - California | 13.0 | 14.3 | 15.3 | 16.5 | 19.1 | 20.2 | 21.2 | 22.2 | 23.0 | 24.1 |
| EE - Oregon | 629.7 | 682.0 | 742.1 | 782.7 | 881.6 | 899.7 | 930.2 | 977.0 | 1,024.5 | 1,134.2 |
| EE - Washington | 119.5 | 129.4 | 138.6 | 147.5 | 153.9 | 161.3 | 167.6 | 173.3 | 178.9 | 183.2 |
| EE - Utah | 1,173.9 | 1,315.4 | 1,477.2 | 1,654.8 | 1,821.7 | 1,961.8 | 2,082.8 | 2,227.5 | 2,388.6 | 2,574.9 |
| EE - Idaho | 77.6 | 87.0 | 96.4 | 106.1 | 112.9 | 120.2 | 127.0 | 134.4 | 141.9 | 147.0 |
| EE - Wyoming | 149.0 | 164.4 | 179.5 | 193.4 | 203.7 | 216.1 | 228.2 | 240.0 | 248.2 | 255.5 |
| Total System | 2,162.7 | 2,392.5 | 2,649.2 | 2,901.1 | 3,192.9 | 3,379.4 | 3,556.9 | 3,774.5 | 4,005.1 | 4,318.9 |

Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com

Thank you for participating.

# PacifiCorp - Stakeholder Feedback Form

## 2025 Integrated Resource Plan

PacifiCorp (the Company) requests that stakeholders provide feedback to the Company upon the conclusion of each public input meeting and/or stakeholder conference calls, as scheduled. PacifiCorp values the input of its active and engaged stakeholder group, and stakeholder feedback is critical to the IRP public input process. PacifiCorp requests that stakeholders provide comments using this form, which will allow the Company to more easily review and summarize comments by topic and to readily identify specific recommendations, if any, being provided. Information collected will be used to better inform issues included in the 2025 IRP, including, but not limited to the process, assumptions, and analysis. In order to maintain open communication and provide the broader Stakeholder community with useful information, the Company will generally post all appropriate feedback on the IRP website unless you request otherwise, below.

Date of Submittal: 12/17/2024


*Name: Logan Mitchell

Title: Climate Scientist and Energy Analyst

*E-mail: Logan@UtahCleanEnergy.org

Phone:

*Organization: Utah Clean Energy

Address:

City: State: Zip:


Public Meeting Date comments address:

☐ Check here if not related to specific meeting

List additional organization attendees at cited meeting:

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.

- Request for a 2025 IRP technology agnostic model sensitivity that reduces portfolio emissions by 85% by 2032.

☐ Check here if you do **not** want your Stakeholder feedback and accompanying materials posted to the IRP website.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.

Impacts from the changing climate are now having material impacts on PacifiCorp and ratepayers, from wildfire impacts that present one of the most significant financial threats to utilities, to heat waves driving up peak demand and power prices, to drought affecting hydroelectric generation, extreme weather events affecting infrastructure, and more. There's broad consensus in the need to limit warming to below 2°C, at which point many societal risks and costs from climate change impacts are projected to substantially increase.

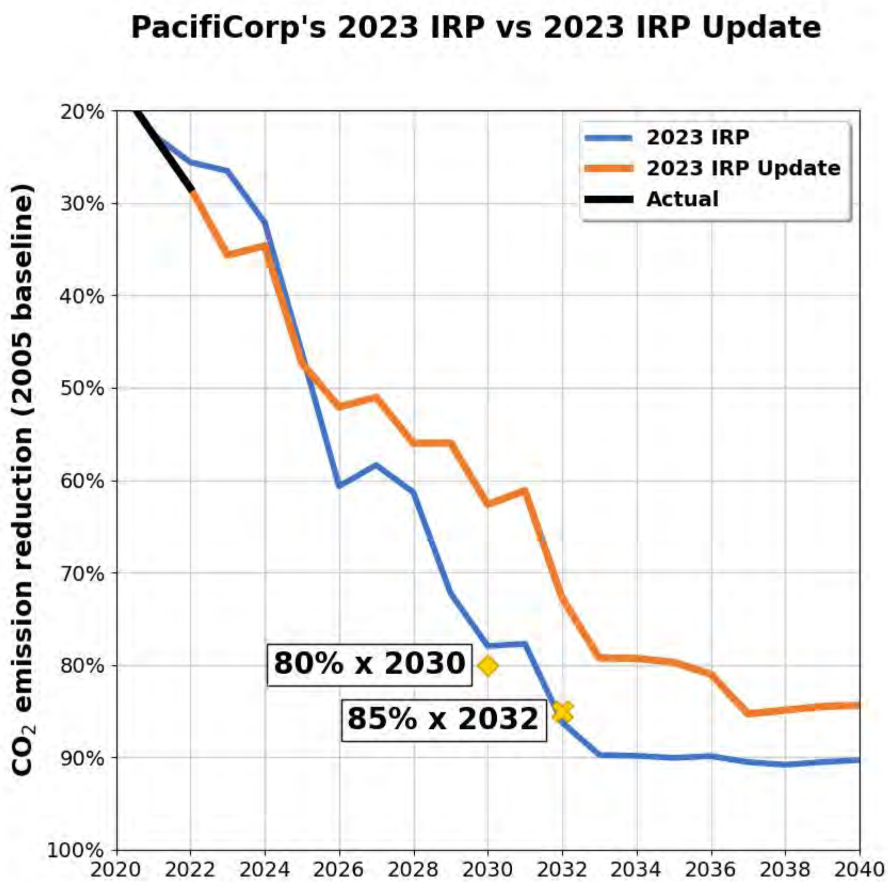
To keep warming below 2°C, US economy wide emissions need to decrease by 50-52% by 2030 using a 2005 baseline, as discussed in Utah Clean Energy's direct testimony in Rocky Mountain Power's 2024 rate case [1]. A recent research study used six coupled energy-economy models to investigate sectoral emission reductions needed to reach that economy wide emission reduction target [2]. This report found that the most cost-effective near-term emission reductions come from the electricity sector. Therefore, to achieve US economy wide emission reductions of 50-52% by 2030, the electricity sector would need to reduce greenhouse gas emissions by 80% by 2030. This analysis provides critical guidance to the entire electricity sector in the US about the amount of emission reductions needed to mitigate the costs and risks posed by climate change.

However, given the timeframe of resource planning and procurement, and the 2025 IRP Action Plan window that will extend through 2028, we are concerned that there is not enough time for the IRP model to achieve that 80% reduction by 2030 endogenously.

We therefore have the following request: A technology agnostic IRP model sensitivity run that determines the least-cost approach to achieving an 85% reduction in PacifiCorp's greenhouse gas emissions by 2032 using a 2005 baseline. These targets are largely in line with the emission reduction pathway in the 2023 IRP preferred portfolio (see figure below).

In other words, PacifiCorp's 2005 baseline CO2 emissions were 54.60 million metric tons, so we are requesting a sensitivity such that PacifiCorp's 2032 emissions are at or below 8.19 million metric tons (85% reduction).

* Required fields




**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.

[1] Phase I Direct Testimony of Dr. Logan Mitchell of Rocky Mountain Power, Docket No. 24-035-04 (filed Oct 17, 2024) https://pscdocs.utah.gov/electric/24docs/2403504/335983PhsIDirTstmnyLoganMitchelUCE10-17-2024.pdf

[2] Bistline, John, Nikit Abhyankar, Geoffrey Blanford, Leon Clarke, Rachel Fakhry, Haewon McJeon, John Reilly, et al. "Actions for Reducing US Emissions at Least 50% by 2030." Science 376, no. 6596 (May 27, 2022): 922–24. https://doi.org/10.1126/science.abn0661.

**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.

Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com
Thank you for participating.

**PacifiCorp's Response:**
Thank you very much for your feedback and recommendation. PacifiCorp is currently evaluating the variety of sensitivity requests received and, should sufficient modeling time be available, will incorporate this sensitivity in the March 31 final filing.

* Required fields

# PacifiCorp - Stakeholder Feedback Form

## Integrated Resource Plan

PacifiCorp (the Company) requests that stakeholders provide feedback to the Company upon the conclusion of each public input meeting and/or stakeholder conference call, as scheduled. PacifiCorp values the input of its active and engaged stakeholder group, and stakeholder feedback is critical to the IRP public input process. PacifiCorp requests that stakeholders provide comments using this form, which will allow the Company to more easily review and summarize comments by topic and to readily identify specific recommendations, if any, being provided. Information collected will be used to better inform issues included in the IRP, including, but not limited to the process, assumptions, and analysis. In order to maintain open communication and provide the broader Stakeholder community with useful information, the Company will post appropriate feedback on the IRP website based on your selection below.

Date of Submittal 2025-01-08

*Name: Don Hendrickson
Title:
*E-mail: dhendrickson@energystrat.com
Phone: 8016521292
*Organization: Utah Association of Energy Users
Address: 111 E Broadway, Suite 1200
City: SLC State: UT Zip: 84111

Public Meeting Date comments address: ☐ Check here if related to specific meeting

List additional organization attendees at cited meeting:

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.
Draft IRP Document

☒ Check here if you want your Stakeholder feedback and accompanying materials posted to the IRP website.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.
1. Long Duration Battery Storage / Iron Air Battery a. Please address the feasibility of the Iron Air Battery storage technology. b. In table 7.3 the 100 hour Iron Air battery has a resource availability of 2030, and a commercial operation year of 2032. Commercial operation year is defined in the IRP as \u001CYear when the Resource is available for generation and dispatch. It is based on the Resource Availability Year plus the Total Implementation Time.\u001D Please discuss how these two years are used in the modeling for Iron Air batteries and if Iron Air batteries are considered having capacity value prior to the commercial operation year. c. In tables 9.5, 9.6, 9.7 and 9.10 please provide the detail of the resources on the \u001CRenewable Battery (Long Duration) row, i.e. what is Iron Air Battery, CAES, Pumped Hydro, other. 2. Previously Contracted Resources, not yet built or operational a. Please provide a detailed list of previously contracted resources noted in the Executive Summary on pgs. 4-5: \u001CThe 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.\u001D Please include year (2025 or 2026), the resource type and, if battery storage, the type of battery. b. Please indicate if any of the previously contracted resources are included in the Expansion Options section of table 9.10 c. Please indicate or confirm the previously contracted resources are included in the Planned Resources section of tables 9.11 and 9.12 d. Consider adding a separate section to tables 9.11 and 9.12 for previously contracted resources 3. Please explain in detail the change in modeling hydrogen resources as noted in the Chapter 7 highlights: \u001CIn 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.\u001D

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4. In figure 9.13 please provide the detail of what is in the \u001COther\u001D category 5. Please provide versions of figures 9.13 and 9.14 net of Demand Response and Energy Efficiency resources. 6. Master list of Expansion Resources and Previously Contracted Resources \u0013 Please provide a master list of Expansion and Previously Contracted resources with the following information a. Online year, or year assumed able to meet capacity requirements b. Average Summer and Winter Capacity Contribution, i.e. tables 9.13 and 9.14 c. For Expansion Resources, the corresponding row in tables 7.2 and 7.3 for each resource

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**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.

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**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.

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Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com

Thank you for participating.

**PacifiCorp Response (2/11/2025)**

1. As indicated on page 143 of the 2025 IRP Draft Volume I, input assumptions for the 100-hour iron-air battery were developed in cooperation with Form Energy based on their commercial long-duration storage product. For more information, please visit: https://formenergy.com/technology/battery-technology/.

In Table 7.3 the 100-hour iron-air battery mistakenly has a resource availability year of 2030 and a commercial operation year of 2032. The availability year and commercial operation year of the 100-hour iron-air battery should be 2028 and 2030 respectively. The commercial operation year for the 100-hour iron-air battery was already being modeled as 2030 in PLEXOS. The first year the 100-hour iron-air battery may provide capacity value in PacifiCorp's 2025 IRP modeling is 2030. While this product is currently available, it may take a few years for production capacity to support the quantities contemplated in PacifiCorp's 2025 IRP.

The long-duration storage category for selections in the preferred portfolio and any portfolio variants includes both 8-hour lithium ion batteries and 100-hour iron-air batteries. For detail of the resources included on the "Renewable Battery (Long Duration)" row in Table 9.10, please refer to the public LT model report for the 2025 IRP draft preferred portfolio included on the public data disc: (P)_LT_25I.LP.iLT.21.Integrated.EP.2409MN.Base IntTrans_106955 v78.1.xlsb. Specifically, please refer to tab "Portfolio Data" and filter column T for "Renewable - Battery (Long Duration)". LT model reports for Tables 9.5, 9.6 and 9.7 will be available along with the final filing of the 2025 IRP. Please note, PacifiCorp is considering updates to how storage resources are categorized in Tables and Figures included throughout the 2025 IRP document to help stakeholders identify the specific storage resource types being represented.

2. The previously contracted resource totals referenced on pages 4 and 5 of PacifiCorp's 2025 IRP Draft Volume I are nameplate installed capacity MWs while Tables 9.11 and 9.12 in PacifiCorp's 2025 IRP Draft Volume I present Western Resource Adequacy Program (WRAP) qualifying capacity contribution values in MWs. For nameplate capacity detail on all of the previously contracted energy storage resources, please refer to Table 6.6 and Table 6.11 in PacifiCorp's 2025 IRP Draft Volume I. The qualifying capacity contribution detail will be provided with the confidential workpapers in PacifiCorp's final IRP filing. With regard to the online date for energy storage in those tables, the Panguitch battery achieved commercial operation in 2020, the Oregon Institute of Technology (OIT) battery is expected to reach commercial operation in 2025, and all of the other previously contracted energy storage is expected to reach commercial operation in 2026. Additional detail on nameplate capacity of previously contracted wind and solar resources may be found on tab "Portfolio Data" in file (P)_LT_25I.LP.iLT.21.Integrated.EP.2409MN.Base IntTrans_106955 v78.1.xlsb on the public data disc accompanying PacifiCorp's 2025 Integrated Resource Plan Draft.

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The only resources included in the totals presented on pages 4 and 5 also included in the “Expansion Options” section of Table 9.10 are the 2026 value for battery storage which includes Dominguez BESS, Enterprise BESS, Escalante BESS, Granite Mountain BESS and Iron Springs BESS battery storage facilities totaling 520 MWs of nameplate installed capacity. Dominguez BESS is a stand-alone energy storage resource while the remaining four battery storage resources will be added at existing solar resources and use surplus interconnection. All five of these four-hour battery storage resources were committed since the filing of the 2023 IRP Update and are scheduled to come online ahead of the peak summer season in 2026.

The previously contracted resources referenced on pages 4 and 5 are not included in the “Planned Resources” section of Tables 9.11 and 9.12. These resources are included in the “Existing Resource” section of Tables 9.11 and 9.12, including the five battery storage facilities referenced above. PacifiCorp has discovered errors related to PLEXOS modeling setups of WRAP qualifying capacity contribution values which caused errors in Tables 9.11 and 9.12, along with Tables 6.14, 6.15, 9.13 and 9.14 and Figures 6.2 and 6.4-6.7. These modeling setups will be corrected along with all aforementioned Tables and Figures in the final filing of PacifiCorp’s 2025 IRP.

3. The decision to model hydrogen as an alternative fuel, including electrolyzer cost and performance, has been discussed in several meetings throughout the course of the 2025 IRP public input meeting series (e.g. August 14-15, 2024 public input meeting). PacifiCorp considered both tank and cavern storage options for hydrogen which in combination with electrolysis could allow for increased clean energy production. The tank option is being modeled in PLEXOS in the 2025 IRP. PacifiCorp decided to model the hydrogen storage peaker resource for the 2025 IRP after soliciting stakeholder feedback and comparing the viability of tank or cavern storage options for hydrogen fuel to hydrogen resource options requiring a hydrogen pipeline.

4. Figure 9.13 includes existing, planned and proxy resources for each category. “Contract” includes long term contract purchases, sales and interruptible contracts. “Other” includes hydro, hydro storage, geothermal and nuclear resources.

5. PacifiCorp has not prepared versions of Figures 9.13 and 9.14 net of demand response and energy efficiency resources. The workpapers supporting Figures 9.13 and 9.14 may be found on the public data disc for PacifiCorp’s draft 2025 IRP: (P)_Fig 9.13-ST Cost Summary (106957) v78.3 - Preferred Portfolio with Energy Pivot Chart.xlsb and (P)_LT_25I.LP.iLT.21.Integrated.EP.2409MN.Base IntTrans_106955 v78.1.xlsb.

6. The company has not produced the requested list of resources and information. Details related to Tables 9.13 and 9.14 may be found on the public data disc for PacifiCorp’s draft 2025 IRP: (P)_Fig 6.2-6.7, Tables 6.14-6.15, 9.11-14, 2025 IRP - L&R.xlsx. As stated in response 2 above, Tables 9.13 and 9.14 contain erroneous values due to a modeling error of WRAP qualifying capacity contribution values. These tables will be corrected in the final 2025 IRP filing.

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# PacifiCorp - Stakeholder Feedback Form

## 2025 Integrated Resource Plan

PacifiCorp (the Company) requests that stakeholders provide feedback to the Company upon the conclusion of each public input meeting and/or stakeholder conference calls, as scheduled. PacifiCorp values the input of its active and engaged stakeholder group, and stakeholder feedback is critical to the IRP public input process. PacifiCorp requests that stakeholders provide comments using this form, which will allow the Company to more easily review and summarize comments by topic and to readily identify specific recommendations, if any, being provided. Information collected will be used to better inform issues included in the 2025 IRP, including, but not limited to the process, assumptions, and analysis. In order to maintain open communication and provide the broader Stakeholder community with useful information, the Company will generally post all appropriate feedback on the IRP website unless you request otherwise, below.

Date of Submittal: Jan 14, 2025


*Name: Logan Mitchell    Title:

*E-mail: Logan@utahcleanenergy.org    Phone:

*Organization: Utah Clean Energy

Address:

City:    State:    Zip:


Public Meeting Date comments address: ☐ Check here if not related to specific meeting

List additional organization attendees at cited meeting:

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.

- CO2 Emissions from the 2025 IRP Draft

☐ Check here if you do **not** want your Stakeholder feedback and accompanying materials posted to the IRP website.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.

The CO2 emissions in the 2025 IRP Draft in the years 2025-2030 are lower than they were in the 2023 IRP and the 2023 IRP Update, according to Figure 9.10 in the 2025 IRP Draft. However, in those years PacifiCorp is planning to procure a very limited amount of new emission free generation resources like solar and wind, far less than what was included in the 2023 IRP and 2023 IRP Update. We have a few questions to help us gain an understanding of what explains this change.

1) Do the emissions in the 2025 IRP Draft include emissions from market purchases?
2) If so, how are market purchase emissions calculated, and what data inputs were used?
3) If not, we request that these emissions are estimated and accounted for in the final 2025 IRP.
4) More generally, what is causing the lower emissions in the 2025 IRP Draft as compared to the 2023 IRP and 2023 IRP Update in the 2025-2030 timeframe? In the Chapter 9 highlights, four factors are listed: retirements, additional natural gas conversions, reduced capacity factors at existing coal and natural gas facilities, and installation of carbon capture and sequestration (CCS). However, retirements and gas conversions have been planned for a while and the CCS installation wouldn't happen until 2030. So, what is the primary driver of emission reduction in 2025-2030, especially in the year 2025, and how is that calculated, and what inputs were used?

Lastly, Figure 9.12 shows Oregon allocated emission reductions relative to HB2021 target. We request companion figures that show how emissions in the rest of PacifiCorp's states and each state individually change as a result of this allocation to Oregon.

**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.

**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.

* Required fields

Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com
Thank you for participating.

**PacifiCorp Response (2/11/25)**

1) Yes.
2) As described on page 226 of the Draft, market purchases are assigned emissions at a rate of 0.428 metric tons $CO_2e$ per MWh. The market purchases selected in the 2025 IRP Draft preferred portfolio are used as inputs from 2025 to 2045.
3) N/A
4) The 2025 IRP has lower load than the prior versions, as discussed in Appendix A in Volume II of the 2025 IRP Draft. Additionally, market prices for electricity and natural gas in the 2025 IRP incorporate increased volatility, leading to more periods where it is cost-effective to run gas plants instead of coal plants, and more periods when low-cost market purchases displace emitting resources, with limits on wholesale sales also playing a role. Please refer to Chapter 9 for details on the calculation of system emissions.

PacifiCorp is actively looking for helpful ways to present emissions data in the final 2025 IRP and will consider this request to present state-level emissions data.

# PacifiCorp - Stakeholder Feedback Form

Integrated Resource Plan

PacifiCorp (the Company) requests that stakeholders provide feedback to the Company upon the conclusion of each public input meeting and/or stakeholder conference call, as scheduled. PacifiCorp values the input of its active and engaged stakeholder group, and stakeholder feedback is critical to the IRP public input process. PacifiCorp requests that stakeholders provide comments using this form, which will allow the Company to more easily review and summarize comments by topic and to readily identify specific recommendations, if any, being provided. Information collected will be used to better inform issues included in the IRP, including, but not limited to the process, assumptions, and analysis. In order to maintain open communication and provide the broader Stakeholder community with useful information, the Company will post appropriate feedback on the IRP website based on your selection below.

Date of Submittal 2025-01-15

*Name: Rob Creager Title: Executive Director
*E-mail: john.jenks1@wyo.gov Phone: 3078232403
*Organization: Wyoming Energy Authority
Address: 1912 Capitol Ave #305
City: Cheyenne State: WY Zip: 82001

Public Meeting Date comments address: ☐ Check here if related to specific meeting

List additional organization attendees at cited meeting:

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.
Demand Forecasting and Generation

☒ Check here if you want your Stakeholder feedback and accompanying materials posted to the IRP website.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.
Demand Forecasting and Generation: According to the Draft IRP, PacifiCorp projects that Wyoming is to only experience 0.03% annual load growth from the years 2025-2034 (Vol. 2 pg. 3). As the state agency that promotes and supports the development of commercial energy projects, the Wyoming Energy Authority is aware of the demand for hundreds of megawatts of generation capacity in our State. In addition, as is widely known, WECC and the United States are expected to experience annual electric load growth rates closer to 3% or higher. Specifically in Wyoming, we know that Rocky Mountain Power has had requests for large energy users--like data centers--and have pressing needs to serve other organic growth in communities, like in the case of Laramie. Further explanation of the load growth forecasting in Wyoming is required to accurately reflect our development interest and in order for PacifiCorp to meet these vital economic development needs. Under the demand forecasting system-wide (Vol. 1 pg. 31), there is mention of non-CAISO WECC region projected to experience annual growth of 1.8% through 2030. There is further discussion of this on pg 98. However, demand forecasts for all six states in PacifiCorp service territory (Vol. 2 pg 3) fall under the demand forecast by WECC in its latest WARA (Dec 2024). The exception is Utah which is making up for projected anemic growth particularly in Wyoming and Idaho. In addition, as stated in WECC's latest WARA, forecasts beyond 2025 outperform forecasts from previous years 2022 and 2023. The WEA would recommend further clarification on the demand forecasts here, in particular to better understand the assumptions PacifiCorp is using in demand forecasting (e.g. high-growth scenarios because many studies seem to be raising the forecast for load growth). While possibly intuitive, further explanation on page 98 as to why the non-PacifiCorp regions in WECC (California and Desert Southwest) are expected to see higher demand growth. In Vol 1 on page 8, it is stated, "Changes to PacifiCorp's load forecast are driven by lower projected demand from new large customers who are expected to provide or pay for their necessary resources and transmission." WEA feels that this should be further clarified either here or in

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Chapter 7 to better understand what this means and how this affects the assumptions into the models affecting demand forecasts. (On its surface, it appears PacifiCorp is projecting lower demand from new large customers which, again, is incongruent with the regional and national facts on the ground). Chapter 5 discusses resource adequacy and beginning in Volume 1 on page 102 in the Adequacy Assessment section, there is a line about higher data center loads could lead to reliability shortfalls. This, coupled with increasing capacity constraints on the system, from an economic development perspective, is alarming as it could mean that it could be harder to site large-load economic development projects in Wyoming moving forward. Further explanation is necessary. Tied to the above bullet point, Chapter 6, there is mention regarding "the uncertainty in the company's load and resource balance is increasing...the resources and load relationships ultimately drive the frequency and characteristics of the relatively extreme conditions that are most likely to trigger reliability shortfalls." It is also mentioned that PacifiCorps's system is capacity deficient relative to WRAP compliance by Summer of 2026 without resorting to short-term capacity procurements like market purchases. While the WEA appreciates PacifiCorp's plans to extend the life of many of its generation units in Wyoming, WEA is also concerned that if the company will be resorting further trading on the open market which can lead to more volatile costs that will be passed on to our residents. WEA recognizes that PacifiCorp, like all utilities, trades in a market. However, as resources become more intermittent and scarce, trading on an open market will become more competitive and thus drive up costs. In addition, the retirements/exit of Colstrip, Craig, and Hayden units take away critical baseload at a time when generation resources are critical as evident in the IRP.

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**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.

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**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.

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Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com

Thank you for participating.

**PacifiCorp Response:**
The Company appreciates the feedback regarding the need for further clarifications on the demand forecasts and the drivers of the change to PacifiCorp's load forecast. The Company will enhance its response in the final IRP deliverable.

1) The base load forecast used in the 2025 Integrated Resource Plan (IRP) Draft includes minimal incremental industrial load growth given the Company's understanding that future projects will be served with specially designated resources that will not affect the Company's need to procure new resources to serve systemwide load growth. The final 2025 IRP will include sensitivities that represent a range of possible load forecasts, including high growth in data center loads.
2) As presented in the January 22-23, 2025 public input meeting, the 2025 IRP includes greater volatility in market prices and, after 2028, does not allow market purchases during peak hours. This means that the resource selections included in portfolios must be sufficient to serve peak loads on their own without relying on the market. Additionally, the inclusion of constraints modeling compliance with the Western Resource Adequacy Program (WRAP) starting in 2028 requires portfolios to include significant resource acquisition in the early years of the horizon. The Company's capacity position in 2026 is outside the scope of the 2025 IRP, which does not allow new resources to be selected until 2027. The Company's expected exits from Colstrip, Craig, and Hayden units are also included in the modeling for the 2025 IRP, and the Company is aware that the baseload generation provided by these units will need to be replaced.

# PacifiCorp - Stakeholder Feedback Form
## 2025 Integrated Resource Plan

PacifiCorp (the Company) requests that stakeholders provide feedback to the Company upon the conclusion of each public input meeting and/or stakeholder conference calls, as scheduled. PacifiCorp values the input of its active and engaged stakeholder group, and stakeholder feedback is critical to the IRP public input process. PacifiCorp requests that stakeholders provide comments using this form, which will allow the Company to more easily review and summarize comments by topic and to readily identify specific recommendations, if any, being provided. Information collected will be used to better inform issues included in the 2025 IRP, including, but not limited to the process, assumptions, and analysis. In order to maintain open communication and provide the broader Stakeholder community with useful information, the Company will generally post all appropriate feedback on the IRP website unless you request otherwise, below.

Date of Submittal: 1/16/2025


*Name: Rose Monahan, Staff Attorney
Matt Gerhart, Senior Attorney

Title:

*E-mail: Rose.monahan@sierraclub.org
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Phone: 415-977-5704

*Organization: Sierra Club

Address: 2101 Webster Street, Suite 1300

City: Oakland State: CA Zip: 94612


Public Meeting Date comments address: 1/22-23/2025 ☐ Check here if not related to specific meeting

List additional organization attendees at cited meeting:

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.

- Feedback on Draft 2025 IRP

☐ Check here if you do **not** want your Stakeholder feedback and accompanying materials posted to the IRP website.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.

## Requests for additional explanation/information at the Jan. 22-23 Public Input Meeting

- **Explain why PacifiCorp did not select the Integrated Base MR portfolio as its preferred portfolio**
  - The Integrated Base MR portfolio has, as a practical matter, the same costs as the preferred portfolio, but significantly lower CO2 emissions. Given its much lower CO2 emissions, the Integrated Base MR portfolio better protects against the risk of future federal CO2 regulations than PacifiCorp's preferred portfolio. In addition, because the Integrated Base MR portfolio would have lower emissions of other pollutants (e.g., SO2, NOx, etc.) than PacifiCorp's preferred portfolio, the Integrated Base MR portfolio better protects against the risk of future federal regulations imposing stricter limits on conventional pollutants such as SO2 and NOx. Thus, when both cost and risk are considered, the Integrated Base MR portfolio appears to be the least-cost, least-risk portfolio.
  - The draft IRP does not offer an adequate explanation of how PacifiCorp selected the MN portfolio as the preferred portfolio.

- **Clarify how the IRP accounted for the risk of future carbon regulations**
  - At the January public input meetings and in the final 2025 IRP, PacifiCorp must provide further clarity on each of the price-policy scenarios, including the specific CO2 prices and/or other constraints assumed under each of the scenarios. For instance, the draft 2025 IRP does not explain what assumptions or constraints were used in the "MR" price-policy scenario, except to say that only the MR scenario would be compliant with the EPA's 111(d) regulation and that it includes "current EPA regulations." The draft does not include a list of "current EPA regulations" or state what constraints were included in the MR scenario in order to comply with the 111(d) regulation. Moreover, since the 111(d) regulation is not a carbon tax, it is unclear whether MR

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also included an assumed carbon price or whether zero carbon price was used under this scenario. Additionally, although PacifiCorp representatives stated in public input meetings (e.g., a public input meeting held for the Washington Clean Energy Implementation Plan on October 29, 2024) that "MN" is not "no CO2," it is unclear whether any carbon price was included in the MN scenario, particularly because "MN" is described as "medium gas/zero CO2." Draft IRP at 175. Figure 8.4 appears to indicate that no CO2 was assumed under MR or MN, but again it is not clear. This information should be included in narrative form, not buried in spreadsheets, and an explanation of each portfolio at the January meetings would greatly help stakeholders in their review of the draft IRP.

  - Regarding the final 2025 IRP, for several IRP cycles, PacifiCorp has used an assumed CO2 price not to represent an anticipated carbon tax but to represent the risk of future environmental regulations impacting fossil fuel generation. PacifiCorp should continue that practice in the 2025 IRP. As a 20-year document, failing to account for the risk of future environmental regulations places significant risk on customers that the chosen resource strategy will not comply with future regulations and require rapid and expensive transitions to cleaner technologies that could have been achieved over a longer time frame. Lack of CO2 pricing further ignores the external costs of continuing to burn fossil fuels, which Utah's IRP Guidelines explicitly require PacifiCorp to take into account.

- **Provide additional explanations of Tables 9.5 to 9.7**
  - Tables 9.5, 9.6, and 9.7 purport to provide the Washington, Oregon, and remaining states' jurisdictional portfolios. The tables differ with respect to new resources by showing the amount of new resources allocated to each jurisdiction. However, the tables appear to contain the identical actions for existing resources.
  - We are unclear as to how the OR and WA jurisdictional portfolios can lawfully include actions contained in these tables. For example, both Tables 9.5 and 9.6, for WA and OR respectively, contain 526 MW of coal CCS in 2030 to reflect CCS on Jim Bridger Units 3-4. However, WA and OR laws prohibit utilities from charging their customers for the costs of coal after 2025 and 2030, respectively. Therefore, we do not understand why 526 MW of coal CCS appears in the portfolios for WA and OR in 2030 and the years thereafter, when state law prohibits that outcome.
  - More generally, we are concerned that PacifiCorp's modeling may be accounting for state-specific requirements when considering new resource procurements, but not fully accounting for state-specific requirements when considering changes to existing units. Explanation on all of these points should be provided at the January meetings.

- **Provide additional explanation of Tables 7.09-7.11**
  - Tables 7.09, 7.10, and 7.11 include a final "Adjusted Total Resource Cost with PTC/ITC Credits" column. Please explain at the January meetings what this column represents, as the column to the immediate left appears to reflect the total resource cost minus ITC/PTC tax credits but then is further adjusted downwards in the final column without explanation.

- **Explain how the Community Renewable Energy Act, HB 411 was factored into the 2025 IRP**
  - The draft IRP says little about how the Company accounted for HB 411 in its modeling and what, exactly, it intends to do to procure clean energy to serve the communities that elect to participate in the program.
  - At the January meetings, PacifiCorp should provide a summary of how HB 411 was incorporated into the draft IRP and the final 2025 IRP should contain a narrative explaining the same, including all constraints, inputs, and manual adjustments made to account for HB 411. The final IRP should also explain which communities are assumed to participate; the aggregate energy and demand of participating communities; how much incremental clean energy PacifiCorp needs to procure by 2030 to serve the participating communities.
  - The action plan is also woefully short on details regarding what steps PacifiCorp will take to procure the clean energy resources needed to serve participating communities. The action plan in the final IRP should provide additional details.

- **<u>Explain Natrium Modeling Assumptions</u>**
    - Sierra Club continues to be concerned that overly optimistic pricing has been used for the Natrium facility, particularly in light of the lack of any binding contractual agreements between PacifiCorp and TerraPower. Please provide additional information regarding what price assumptions were used for the Natrium facility in PLEXOS and how those price assumptions compare to price assumptions used for proxy nuclear resources.
    - Please confirm whether Natrium was endogenously selected by PLEXOS or if PacifiCorp manually added Natrium to the final portfolios.

## <u>Requests for more information and/or modeling to be completed in the final 2025 IRP</u>

- **<u>Clarify in the Final 2025 IRP What Coal Pricing Assumptions Were Used</u>**
    - The draft 2025 IRP (page 192) indicates that, in response to stakeholder feedback, the high gas and market price-policy scenario includes an elevated coal fuel supply cost. However, the draft does not include a chart, similar to Figure 8.5, depicting the differences between the "base" coal forecast and the "elevated" coal forecast. Moreover, Sierra Club assumes that coal pricing is dependent upon the coal plant, as coal supply from the Powder River Basin, for instance, is generally much less expensive than other coal supplies. PacifiCorp should explain, in narrative form, what coal pricing was assumed for each plant. To the extent that this information is considered confident, the final IRP should clearly indicate where this information can be found in PacifiCorp's workpapers and could still provide a general narrative explanation of the differences between the base and elevated forecasts (e.g., "the elevated forecast is approximately 25% higher than the base forecast for the Jim Bridger plant").

- **<u>Model Compliance with HB 2021 and Include an Action Plan for Complying with the 2030 Emission-Reduction Requirement in HB 2021</u>**
    - The brief discussion of HB 2021 on pages 231-32 of the draft IRP leaves many questions unanswered. The draft IRP is unclear as to (1) what methodology was used to reflect HB 2021 requirements in the PLEXOS modeling, including whether any manual adjustments were made; and (2) if the modeling was constrained to meet the emission-reduction requirements of HB 2021, what changes were made to existing resources and which new resources are procured to comply with HB 2021
    - The final 2025 IRP should provide additional detail on how compliance with HB 2021 was modeled, i.e., the specific constraints, assumptions, etc. that were input into PLEXOS, and whether any manual adjustments were made. The final 2025 IRP should also describe how, if at all, compliance with HB 2021 results in changes to existing resources, and new resource procurements.
    - In addition, the final 2025 IRP should provide additional explanation of this statement, which appears on page 232: "Resources allocated to Oregon customers exceed annual energy requirements, and compliance can be achieved through economic specified-source wholesale sales of a portion of the excess supply, where the purchaser is responsible for the associated emissions."
        - This statement, along with Figure 9.12, indicates that the preferred portfolio would not reduce Oregon emissions 80% by 2030, but instead would reduce emissions by only 77.8% by 2030 (excluding specified sales). The draft IRP states that PacifiCorp intends to sell the output of certain Oregon-allocated resources in 2030 and 2031 to come into compliance, on the theory that the emissions from such sales would then not be allocated to Oregon. We are concerned with this approach to HB 2021 compliance, because it would not actually reduce emissions, but merely shift emissions off of PacifiCorp's books. At a minimum, PacifiCorp should explain in the final 2025 IRP:

        - the years in which it intends to sell the output of OR-allocated resources in order to comply with HB 2021, particularly to comply with the 80% by 2030 mandate;
        - the incremental amount of emissions PacifiCorp would need to reduce in 2030 through 2034 to reduce Oregon emissions by 80% in each year; and
        - Which emitting resources allocated to Oregon PacifiCorp intends to sell the output of, and what PacifiCorp's plans are for identifying purchasers of that output.
    - We are also deeply concerned that the preferred portfolio would not achieve compliance with the requirement to reduce Oregon emissions 80% by 2030 or 90% by 2035. Figure 9.12 shows that the preferred portfolio would not reduce Oregon emissions by 90% by 2035, and instead would reduce emissions by only 81.1% (excluding specified sales). In fact, the preferred portfolio would not achieve a 90% reduction in emissions until 2040 (excluding specified sales)– five years after the statutory deadline to reduce emissions 90% by 2035. It is unacceptable for PacifiCorp to present portfolios that do not comply with state law. The draft IRP must be revised such that all portfolios in the final IRP, including the preferred portfolio, reflect timely compliance with the clean energy targets in HB 2021. Non-compliance with HB 2021 also raises questions as to what constraints were inputted to the Oregon jurisdictional model that apparently were not stringent upon to meet Oregon jurisdictional requirements, which reinforces our request above to clearly explain what modeling constraints were used.
    - While HB 2021 allows PacifiCorp to file a Clean Energy Plan in Oregon within 180 days of filing this IRP, that does not justify developing this IRP without constraining all portfolios to comply with HB 2021. This IRP contains an action plan for the next two to four years, and describes actions PacifiCorp will take through 2030. It is deeply concerning that the action plan does not specify the actions PacifiCorp will take to reduce its Oregon emissions 80% by 2030. If PacifiCorp waits until the 2027 IRP to develop an action plan for meeting the 2030 emission-reduction requirement in HB 2021, PacifiCorp may not have enough time to procure any new resources that might be needed to meet the 2030 compliance requirement.
    - Finally, we are concerned that the draft IRP's discussion of emissions omits consideration of HB 2021 or other state policies, as this omission presents an incomplete and inaccurate picture of PacifiCorp's emissions trajectory. Draft IRP at 227 ("The emissions trajectory does not incorporate clean energy targets set forth in Oregon House Bill 2021 or any other state-specific emissions trajectories."). The final IRP should correct this omission and present system-wide emissions inclusive of the impacts of all state-specific policies.

- **<u>Conduct more granular modeling of coal unit retirements by forcing the retirement of specific units in certain portfolios</u>**
    - The only portfolio that forces the model to cease burning coal at coal units is the "No Coal" scenario, in which all existing coal units must stop burning coal by 2030.
    - Because this scenario requires all existing coal units to cease burning coal, it is impossible to glean information on the economics of ceasing to burn coal at any particular unit. Therefore, this scenario does not provide useful information on the economics of individual coal units.
    - The final IRP should present modeling of additional portfolios in which individual coal units, and combinations of coal units, are forced to cease burning coal by 2030. Specifically, the final IRP should include the results from modeling the following portfolios:
        - A portfolio that forces Hunter to cease burning coal by 2030; and
        - A portfolio that forces Jim Bridger to cease burning coal by 2030;
        - A portfolio that forces Huntington to cease burning coal by 2030.
    - If all three portfolios cannot be run, Sierra Club has listed the requested portfolios in order of priority.

- **<u>Modeling of CCS on Jim Bridger Units 3-4</u>**
    - We have several concerns with the modeling of CCS at Jim Bridger Units 3-4, including the modeling conducted for the "No CCS" scenario.

* Required fields

- To begin, the modeling assumption that CCS can come online by the year 2030 is completely unrealistic. As far as we are aware, PacifiCorp has not commenced any permitting, design, or construction work for CCS at Jim Bridger. Thus, the entire CCS project, from permitting and design work through construction and testing, would need to take 5 years or less to come online by 2030. We are not aware of any CCS project on a coal unit that has been installed in this short time frame. Moreover, other utilities have estimated it would take at least double this amount of time–at least 10 years–to design, permit, and construct CCS on a coal unit.
    - To remedy this shortcoming, PacifiCorp should re-run all portfolios and make CCS available for selection in PLEXOS no earlier than 2035.
- Given PacifiCorp's wildly unrealistic assumption as to when CCS can come online, we are concerned that PacifiCorp has used similarly unrealistic assumptions about other aspects of CCS. We are concerned about the accuracy of the assumptions PacifiCorp used for CCS for capital and O&M costs; the CCS capture rate (i.e., what percent of CO2 produced by the coal boilers is captured by the CCS equipment); and the cost to transport and/or store the captured CO2.
    - PacifiCorp has not yet disclosed these CCS assumptions, and thus at this stage it is impossible for us to meaningfully review the assumptions PacifiCorp used in modeling CCS.
    - Given the likelihood that PacifiCorp used overly optimistic assumptions about CCS, we are concerned that the modeling in the draft IRP underestimates the cost to install and operate CCS at Jim Bridger Units 3 & 4.
- In the final 2025 IRP, PacifiCorp must disclose modeling assumptions, particularly price assumptions, used for CCS and ensure that these pricing assumptions provide a realistic forecast of CCS costs.

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**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.

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**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.

As described above, Sierra Club requests additional information on the following topics. This information should, at a minimum, be provided in the final 2025 IRP but we also request, to extent possible, that the Company address these information gaps at the January 22-23, 2025 public input meetings.

***At the January 22nd-23rd public input meeting:***

- Provide greater explanation for why PacifiCorp selected MN as the preferred portfolio, particularly over MR, which has similar costs, lower emissions, and performs better under different pricing assumptions;
- Clarify how the IRP accounted for the risk of future environmental regulations, and provide a narrative summary for each of the base portfolios evaluated (e.g., MN, MR, etc.), including what specific constraints were included in each of these portfolios and what, if any, carbon price was assumed;
- Provide additional explanation for what is depicted in Tables 9.5, 9.6, and 9.7, which purport to provide the Washington, Oregon, and remaining states' jurisdictional portfolios, but appear to show identical actions for existing resources and appear to allocate Washington and Oregon coal shares beyond 2025 and 2030.
- Provide additional explanation of Tables 7.09-7.11, particularly what is represented by the final "Adjusted Total Resource Cost with PTC/ITC Credits" column and what final price point was used in PLEXOS for the supply side resources
- Explain how, if at all, the Community Renewable Energy Act, HB 411 was incorporated into the 2025 IRP modeling
- Explain whether the Natrium nuclear facility was "forced into" the final portfolio or endogenously selected and explain what price assumptions were used for the Natrium facility and how those price assumptions compared to price assumptions for proxy nuclear facilities.

***In the final 2025 IRP:***

* Required fields

1. Disclose what coal pricing was assumed for each coal plant, particularly under the high gas/high coal scenario;
2. Model compliance with HB 2021 emission reduction requirements and include in the action plan specific actions that will be taken in the next 2-5 years to make progress towards HB 2021's emission reduction requirements
3. Conduct more granular modeling of coal unit retirements by forcing the retirement of specific plants in separate portfolios, specifically by separately modeling the retirement of Jim Bridger (units 3-4) by 2030; the retirement of Hunter by 2030; and the retirement of Huntington by 2030.
4. Provide cost assumptions (fixed O&M, variable O&M, CapEx, etc.) used for CCS and ensure that such assumptions provide a realistic picture of likely CCS costs. Adjust the modeling so that CCS is only available beginning in year 2035 or later.

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Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com
Thank you for participating.

**PacifiCorp Response:**

For the Public Input Meeting requests:
PacifiCorp responded to questions and comments regarding these topics at the January 22-23, 2025 public input meeting and is committed to providing time for open discussion as appropriate at future meetings. PacifiCorp continues to welcome dialogue to provide clarity and have further conversations related to these modeling and outcomes questions.

Regarding the final document:
1. Plant coal pricing is expected to be provided for dissemination via workpapers (either confidential or highly confidential depending upon contract/negotiation status).
2. PacifiCorp is including a CEP Update appendix in the 2025 IRP. Compliance with HB 2021 emissions requirements will be modeled. The IRP action plan will include actions that help Oregon reach compliance. Additional detail related specifically to Oregon is likely to be contained in the CEP.
3. These study requests are noted. PacifiCorp will look to complete any of these for which there is sufficient modeling time, prioritizing the various coal units as requested above in comments.
4. This information will be provided in workpapers. Given the role of CCS in meeting federal EPA 111(d) compliance, a 2032 date is the latest date that has been provided for CCS implementation. Jim Bridger units 3 and 4 are modeled in 2030 given the selection of these units in the 2023 IRP update and potential for them to come online earlier as such.

# PacifiCorp - Stakeholder Feedback Form

Integrated Resource Plan

PacifiCorp (the Company) requests that stakeholders provide feedback to the Company upon the conclusion of each public input meeting and/or stakeholder conference call, as scheduled. PacifiCorp values the input of its active and engaged stakeholder group, and stakeholder feedback is critical to the IRP public input process. PacifiCorp requests that stakeholders provide comments using this form, which will allow the Company to more easily review and summarize comments by topic and to readily identify specific recommendations, if any, being provided. Information collected will be used to better inform issues included in the IRP, including, but not limited to the process, assumptions, and analysis. In order to maintain open communication and provide the broader Stakeholder community with useful information, the Company will post appropriate feedback on the IRP website based on your selection below.

Date of Submittal 1/15/25

*Name: WY Commission Title:

*E-mail: wpsc-cir-responses@wyo.gov Phone:

*Organization: WY Commission

Address:

City: State: Zip:

Public Meeting Date comments address: ☐ Check here if related to specific meeting

List additional organization attendees at cited meeting:

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***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.
Draft 2025 IRP questions

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☒ Check here if you want your Stakeholder feedback and accompanying materials posted to the IRP website.

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***Respondent Comment:** Please provide your feedback for each IRP topic listed above.

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**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.

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1.1 Regarding the peak wind generation amounts reflected in Tables 6.14 and 6.15, page 130 of the Draft 2025 IRP as pictured below:
Please see attached original request for information.

1.1.1 Please explain why the two seasons appear to have such a drastic difference.

1.1.2 Based on the Company's overall wind capacity and expected capacity factor, the summer peak wind generation shown in Table 6.14 appears to be considerably less than one would intuitively expect to see. Please explain.

1.2 Does the Company include transmission-only customers in the load forecast?

1.2.1 Does the Company consider transmission-only customers to be special contracts?

1.2.2 Does the Company include special contracts in its load forecast?

* Required fields

1.3 On page 2 of the Draft 2025 IRP, under the "Changes to our Portfolio" subsection, the Company uses phrases like: "continue to evaluate", "continue the process", and "continue to work". Are the bulleted items listed with these phrases still in the Company's preferred portfolio? Please clarify.

1.3.1 Why does the Draft 2025 IRP list the Dave Johnston Unit 3 retirement in 2027 in the "Changes to our Portfolio" section? The 2023 IRP and 2023 IRP Update also shows this unit retiring in 2027 so it does not appear to be a change. Please explain.

1.4 Please provide the PLEXOS ".xml" file along with a copy of the solution file. Please also provide all data input files, custom constraints, scenarios, etc. necessary to perform PacifiCorp PLEXOS model run(s) and receive the same solution.

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**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.

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**PacifiCorp Response:**

1.1 Regarding the peak wind generation amounts reflected in Tables 6.14 and 6.15, page 130 of the Draft 2025 IRP as pictured below: Please see attached original request for information.

Reply: To clarify, the rows labeled "Wind" in Tables 6.14 and 6.15 display the peak capacity contribution of wind for summer and winter, not peak wind generation.

1.1.1 Please explain why the two seasons appear to have such a drastic difference.

Reply: The company has discovered an error in the PLEXOS calculation for the summer peak system capacity, resulting in a significant discrepancy between summer and winter peak capacities. The corrected Summer Peak Resource Capacity will be included in the 2025 IRP February 26-27 public input meeting.

1.1.2 Based on the Company's overall wind capacity and expected capacity factor, the summer peak wind generation shown in Table 6.14 appears to be considerably less than one would intuitively expect to see. Please explain.

Reply: See Response to 1.1.1.

1.2 Does the Company include transmission-only customers in the load forecast?

Reply: The IRP load forecast does not include transmission-only customers. The Company's customers enrolled in Oregon's direct access program are transmission-only customers and excluded from the Company's generation planning load for the IRP.

1.2.1 Does the Company consider transmission-only customers to be special contracts?

Reply: None of the Company's customers who have individual commission-approved special contracts are transmission-only customers.

1.2.2 Does the Company include special contracts in its load forecast?

Reply: Yes, load for customers with individual commission-approved special contracts are included in the load forecast.

1.3 On page 2 of the Draft 2025 IRP, under the "Changes to our Portfolio" subsection, the Company uses phrases like: "continue to evaluate", "continue the process", and "continue to work". Are the bulleted items listed with these phrases still in the Company's preferred portfolio? Please clarify.

Reply: The Company is considering changing the section header from "Changes to Our Portfolio" to "Key Thermal Outcomes." All items listed as bullet points are part of the company's preferred portfolio. We continuously evaluate and move forward in response to events and updated analysis.

* Required fields

1.3.1 Why does the Draft 2025 IRP list the Dave Johnston Unit 3 retirement in 2027 in the "Changes to our Portfolio" section? The 2023 IRP and 2023 IRP Update also shows this unit retiring in 2027 so it does not appear to be a change. Please explain.

Reply: See response to 1.3, above.

1.4 Please provide the PLEXOS ".xml" file along with a copy of the solution file. Please also provide all data input files, custom constraints, scenarios, etc. necessary to perform PacifiCorp PLEXOS model run(s) and receive the same solution.

Reply: The circumstance for providing the ".xml" file is the subject of agreements currently being worked out between Wyoming staff and commission, PacifiCorp and Energy Exemplar.

Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com

Thank you for participating.

* Required fields

# PacifiCorp - Stakeholder Feedback Form

## Integrated Resource Plan

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Date of Submittal 2025-01-24


*Name: David Williams Title:

*E-mail: dcwilli@utah.gov Phone:

*Organization: Utah Division of Public Utilities

Address:

City: State: Zip:


Public Meeting Date comments address: 01-23-2025 ☒ Check here if related to specific meeting

List additional organization attendees at cited meeting:

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.
Draft IRP; Iron-Air Batteries

☒ Check here if you want your Stakeholder feedback and accompanying materials posted to the IRP website.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.
In the 2023 IRP, the Company evaluated a "No Forward Tech" portfolio (P06, see Figure 9.11 "Increase/(Decrease) in Proxy Resources when all Forward Technology is Eliminated from the P-MM Portfolio"). The description of P06 stated: "The P06-No Forward Tech portfolio is a variant of the P-MM portfolio that eliminates all future resource options which are not currently available within the existing PacifiCorp portfolio." This scenario disallowed nuclear and non-emitting peakers. The technology of non-emitting peakers was not established at the time of the 2023 IRP, and so this technology was not currently available, and counted as "forward tech". P06 was run with non-gas options available (i.e. natural gas was not allowed to be selected) (Table 8.12). At the Jan. 22-23 public input meetings for the 2025 IRP, the Division and other parties asked about the 100-hour iron-air batteries selected in the 2025 IRP. The Company performed an analysis on a "No Nuclear" scenario (e.g. Table 8.5; Figure 9.17 of 2025 Draft IRP). The Company said that iron-air batteries were allowed to be selected in the no nuclear scenario. The Division asked if there should be a "no new technologies" case that did not allow either nuclear or iron-air batteries. The Company responded (this is a paraphrase, not a direct quote): "The iron-air battery technology is viable at the commercial level, even though it's not being used yet at the utility scale. Therefore, the iron air technology is different than the non-emitting peakers in the 2023 IRP." The Division appreciates that the iron-air batteries could be different (developmentally speaking) than the non-emitting peakers in the 2023 IRP. However, the iron-air batteries are not currently available at the utility level. There could be unforeseen challenges that prevent a utility-scale project. See, e.g., "Will Iron-Air Batteries Revolutionize Renewable Energy Storage?", August 19, 2024, at https://www.environmentenergyleader.com/stories/will-iron-air-batteries-revolutionize-renewable-energy-storage,48339 "Despite their benefits, iron-air batteries face several challenges: Slower Response Time: Iron-air batteries may struggle in applications

* Required fields

requiring rapid energy discharge and recharge cycles due to their slower response time. ... Developmental Stage: Iron-air technology is still in its early stages, and unforeseen technical and scalability challenges could emerge as the technology matures." Thus it is not yet settled how effective this technology will be at the utility scale. The Division requests that a "no new forward technology" scenario be evaluated in the 2025 IRP, with both nuclear and iron-air batteries disallowed. Natural gas should be allowed in this scenario.

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**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.

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**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.

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Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com

**PacifiCorp Response (2/17/25)**

Thank you for your feedback. PacifiCorp will consider this request to conduct a study that does not allow the selection of 100-hour iron air batteries.

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# PacifiCorp - Stakeholder Feedback Form
## Integrated Resource Plan

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Date of Submittal 2025-01-25


*Name: Sean Maher    Title:

*E-mail: spmaher67@gmail.com    Phone:

*Organization: Utah Environmental Caucus

Address:

City: Salt Lake City    State: UT    Zip:


Public Meeting Date comments address:    ☐ Check here if related to specific meeting

List additional organization attendees at cited meeting:

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.

Geothermal

☒ Check here if you want your Stakeholder feedback and accompanying materials posted to the IRP website.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.

I am surprised and concerned to see how little geothermal energy is included in PacifiCorp\u0019s future energy mix according to the Draft 2025 IRP. The International Energy Agency estimates that geothermal could meet up to 15% of global electricity demand growth to 2050, and the Western Governor\u0019s Association projects 12,558 MW of new energy in the western US from conventional geothermal alone. This figure excludes enhanced geothermal technologies, which are already planned to produce an additional 2 GW in Utah by 2028 (see CleanTechnica article). Despite this, geothermal is barely visible in the installed MW projections in Figure 1.2, page 5 of the Draft 2025 IRP Volume 1, and it does not appear to increase over time. Geothermal is also absent from Figures 9.13 and 9.14 (Preferred Portfolio's Projected Energy Mix and Capacity Mix, Vol.1 p.233). Why isn\u0019t geothermal being included in these projections, despite being listed among supply-side resource options identified "through external studies, internally generated studies, permitting, regulatory requirements, and stakeholder input" (Vol.1 pp. 139 and 142)?  Recall that PacifiCorp's slide presentation at the July 17-18, 2024 public input meeting included geothermal among Supply Side Resources in the IRP [slide 67], noting that it could "operate as traditional baseload."  The presentation mistakenly claimed that the "soonest commercial operation date possible" is 2030.  The U.S. Energy Information Administration reports that seven states are already producing 17 billion kWh of electricity from geothermal, including four states in PacifiCorp\u0019s service area. Even if 2030 were the soonest that PacifiCorp could generate new geothermal power, why is geothermal not included in a 2025 IRP that runs through 2045?  Though the draft 2025 IRP describes geothermal as a non-CO2-emitting resource with continuous operation (Vol.1 p.188), nowhere in Volumes 1 or 2 is there any indication that geothermal was actually considered for inclusion as a sensitivity or variant factor in any of the potential integrated portfolios.  In its July 15, 2024 response to Ms. Hilding's stakeholder inquiry of June 10, 2024 [Vol.2 pp. 222/340, 223/340], PacifiCorp said it was

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"considering the broad range of geothermal cost scenarios." How was geothermal subsequently modeled for 2025 IRP inclusion? While geothermal is included as a renewable energy source with the 2024 Utah Renewable Communities Request for Proposals [Vol. 1. p.74], how will geothermal be competitive if not included in the 2025 IRP? Is it correct to assume that PacifiCorp also has no plans to interconnect new Utah geothermal resources to the transmission system? How will the multiple new geothermal plants and planned expansions of existing plants (see energy.utah.gov link) be integrated with PacifiCorp\u0019s energy mix?

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**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.

July 2024 PacifiCorp PIM Slide Deck: https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2025-irp/PacifiCorp_2025_IRP_PIM_July_17-18_2024.pdf PacifiCorp's "Supply Side Resources in the IRP" presentation, starting with slide 58, addresses Geothermal on slide 67. EIA on seven states producing geothermal electricity: https://www.eia.gov/energyexplained/geothermal/use-of-geothermal-energy.php Western Governor\u0019s Association projection of conventional geothermal: https://www.eesi.org/files/geothermal_030206_gawell.pdf International Energy Agency on geothermal growth potential: https://www.iea.org/reports/the-future-of-geothermal-energy/executive-summary Enhanced geothermal plant planned for Utah: https://cleantechnica.com/2024/10/21/fervo-energys-update-shows-enhanced-geothermal-is-hot-literally/ Existing and future geothermal in Utah: https://energy.utah.gov/wp-content/uploads/Geothermal-In-Utah.pdf

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**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.

The Final 2025 IRP should specifically address all the concerns and questions raised in this comment about the status of Geothermal in the Draft 2025 IRP. The Final 2025 IRP should include additional portfolio variants and sensitivity cases, with work papers, that include Geothermal as a baseload and peak thermal resource.

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**PacifiCorp Response:**

Geothermal resources are available to be selected by the PLEXOS model in all jurisdictional runs in the LT Capacity expansion planning phase of the model. Geothermal cost characteristics in PLEXOS match the supply side resource table and leverage the National Renewable Energy Laboratory (NREL) escalation curves that reflect anticipated build cost changes over time. In response to the concern related to the earliest availability date, geothermal is available beginning in 2027 in PLEXOS.

The PLEXOS model was able to select Geothermal resources in either Central Oregon or Utah South, given that these are the two locations within the overall PacifiCorp system where Geothermal production is expected to be technically feasible. Resources in these locations (including geothermal) require interconnection upgrades resulting in higher overall costs than are shown in the supply side resource table. The geothermal resources for the 2025 IRP are assumed to be 707 MW in size, and the base build cost modeled in PLEXOS matches the Wasatch Front and Portland North Coast costs on the supply side table. Note that PLEXOS is able to select any number of these resources, including a fractional amount of a unit. Additionally, geothermal resources are assumed to receive production tax credits of 100 or 110 percent depending on the location. The inclusion or exclusion of geothermal resources from any portfolio is related solely to the modeled economics of the resource in competition with all other available resources.

Should there be sufficient time to complete and integrate runs, the IRP team will consider a variant that forces the model to select a minimum of 1 unit of geothermal in each location where the resource is available (much like the offshore wind variant).

While the IRP provides an indication of possible future resource additions, the generic or "proxy" cost and availability estimates represented in the IRP do not and cannot comprehensively represent the available opportunities. As a result the IRP does not represent a commitment to specific future resources, but instead is a road map that identifies how future resources can be assessed and procured. With regard to the competitiveness of geothermal resources, PacifiCorp considers the costs, benefits, and operational characteristics of each resource offered in request for proposal processes and procures the most cost-effective resources, notwithstanding what was included in the most recent IRP preferred portfolio. Several requests for interconnection of geothermal resources have been submitted to PacifiCorp Transmission and are currently in the study process. Once more certainty on the timing any necessary transmission upgrades is known, these resources could be offered to PacifiCorp for consideration in a request for proposal process.

Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com

Thank you for participating.

* Required fields

# PacifiCorp - Stakeholder Feedback Form

## 2025 Integrated Resource Plan

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Date of Submittal: 1/31/25


*Name: Kevin Emerson

Title: Director of Building Efficiency and Decarbonization

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*Organization: Utah Clean Energy

Address: 215 S. 400 E.

City: Salt Lake City State: Utah Zip: 84111


Public Meeting Date comments address: ☒ Check here if not related to specific meeting

List additional organization attendees at cited meeting: Justin Brant, jbrant@swenergy.org and Ramon Alatorre, ralatorre@swenergy.org

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.

- 2025 Conservation Potential Assessment and 2025 IRP draft

☐ Check here if you do **not** want your Stakeholder feedback and accompanying materials posted to the IRP website.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.

Thank you for responding to our last stakeholder comments submitted on November 7, 2024, about the assumptions for the residential energy code baseline in Utah and requesting a year-by-year and state breakout of the DSM selections in the 2023 IRP Update.

With regard to the residential energy code baseline incorporated in the 2025 CPA, we recommend that in the final Conservation Potential Assessment, Table 3-6 (page 42 in the draft CPA) should explicitly reflect that Utah's residential IECC is recognized as equivalent to the 2009 IECC as per U.S. Dept. of Energy (see this link: https://www.energycodes.gov/state-portal). This additional level of specificity will aid in the development of relevant and impactful energy efficiency programs for the new homes sector in Utah.

With regard to the DSM selections in the draft 2025 IRP, we have several comments. First, we are encouraged to see positive growth in the DSM selections within the Action Plan period of the draft 2025 IRP. For example, the DSM selection identifies 492,816 MWh of cost-effective energy efficiency for Utah in 2028 (see chart below). We continue to urge the utility to model and implement all cost-effective energy efficiency investments. For the company to be able to successfully implement electricity-saving programs to reach the 2028 target, it is imperative for the company’s DSM team to begin scaling up current DSM programs immediately. Scaling up immediately will provide energy efficiency program implementors and contractors the time they need to staff up and meet these targets in a timely fashion.

Similarly, we are concerned about the potential impact the significant fluctuations in the DSM resources selected in later years of the draft 2025 IRP could have on the Action Plan period and beyond. The growth, dips, and subsequent increases in the DSM selections for Utah send a mixed signal that creates uncertainty for DSM implementation contractors, complicating the achievement of the DSM targets selected. We strongly recommend that the company’s DSM team work closely with utility energy efficiency contractors to implement the cost-effective DSM selections in a way that gradually and consistently increases/maintain savings targets over the planning horizon.

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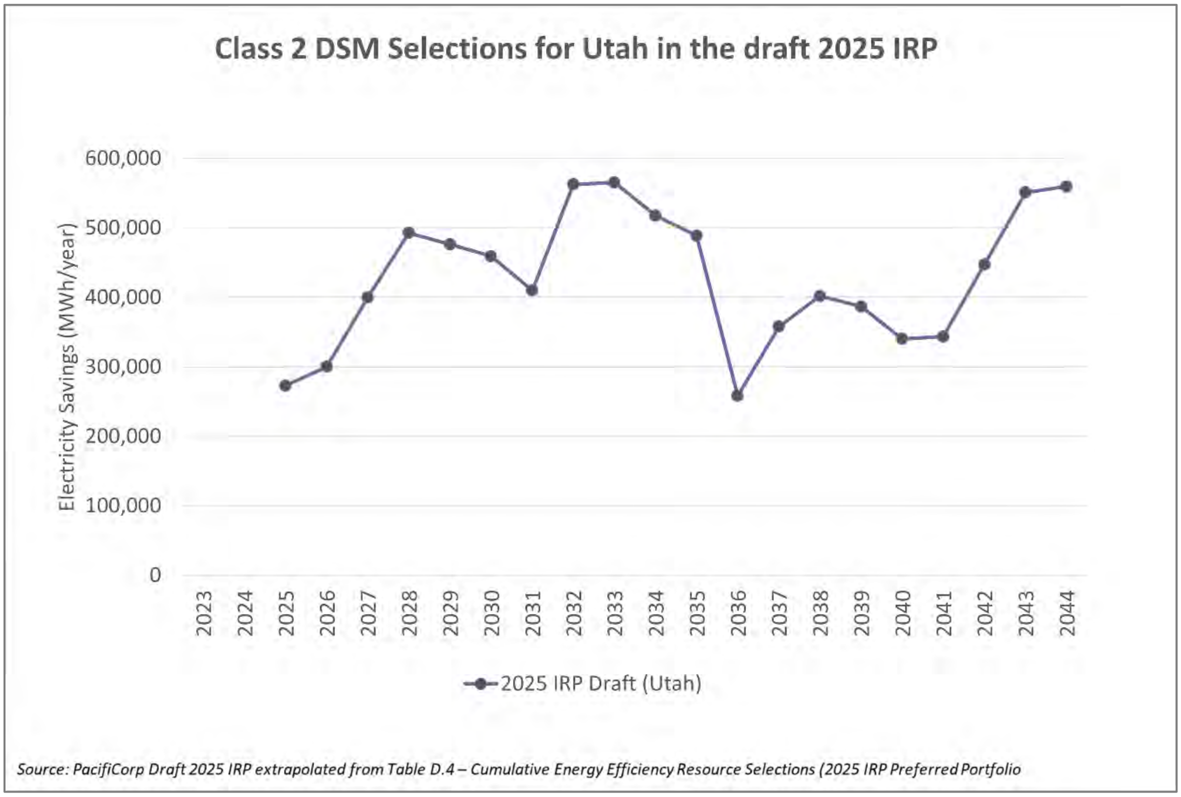
We have additional requests regarding the DSM selections in the draft 2025 IRP:

1. Please explain how other resource selections in the model are impacting the DSM selection each year in Utah. Are fluctuations in the cost-effectiveness of other resources driving the increases and decreases in the amount of DSM resources selected in Utah? And if so, how?

2. Please provide data showing the amount and cost of the energy efficiency bundles selected in the draft 2025 IRP for each year, by state, in dollars per kWh and dollars per kW. This will help us better understand and evaluate the way that energy resources, including DSM resources, are evaluated/selected based on cost.

**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.




**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.

See recommendations embedded in the Respondent Comment section above.

Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com
Thank you for participating.

**PacifiCorp Response (2/21/2025):**

1. All resources available for selection in the PLEXOS long term/capacity expansion model are selected in a competitive manner which is agnostic to technology type.

   Additionally, demand response resources are cumulatively selectable (i.e. the model could delay the selection of multiple years of demand response and later select the total available amount over that period in a single year). This means that in some years, the model may identify cost effective resources which would preclude the need to select demand response, and then a few years later select all the demand response that it had chosen not to select earlier.

Conversely, energy efficiency selections are take-or-leave; something not selected in a particular year cannot be cumulatively added to a future year.

The optimization of DSM is therefore always in competition with other resource options, which are optimized for size and timing.

2. The granular detail requested has not been calculated for the Draft 2025 IRP, but will be provided in the final 2025 IRP to be filed March 31, 2025.

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# PacifiCorp - Stakeholder Feedback Form

Integrated Resource Plan

PacifiCorp (the Company) requests that stakeholders provide feedback to the Company upon the conclusion of each public input meeting and/or stakeholder conference call, as scheduled. PacifiCorp values the input of its active and engaged stakeholder group, and stakeholder feedback is critical to the IRP public input process. PacifiCorp requests that stakeholders provide comments using this form, which will allow the Company to more easily review and summarize comments by topic and to readily identify specific recommendations, if any, being provided. Information collected will be used to better inform issues included in the IRP, including, but not limited to the process, assumptions, and analysis. In order to maintain open communication and provide the broader Stakeholder community with useful information, the Company will post appropriate feedback on the IRP website based on your selection below.

Date of Submittal 2025-02-06


*Name: Jon Martindill Title:

*E-mail: jon@npenergyca.com Phone: (707) 548 - 0367

*Organization: Renewable Northwest

Address:

City: State: CA Zip:


Public Meeting Date comments address: ☐ Check here if related to specific meeting

List additional organization attendees at cited meeting:

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.

Resource Options

☒ Check here if you want your Stakeholder feedback and accompanying materials posted to the IRP website.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.

RNW seeks additional information from and provides recommendations to PacifiCorp regarding its resource options inputs and assumptions in the 2025 Draft IRP. Our feedback consists of four sections: Coal, CCS, Capital Costs, and Biodiesel Coal: Were PacifiCorp's majority-owned coal units available for early retirement? Please explain why all minority-owned coal units retire before 2030, while all but one majority-owned coal unit remains in service through the planning horizon or gas converts. CCS: Page 140 states that \u001Calthough the common abbreviation for carbon capture and storage (CCS) is used, data for these resources does not include sequestration.\u001D Page 143 states that \u001CData for \u0018Carbon Capture Retrofits at existing coal plants\u0019 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.\u001D In Stakeholder Feedback Form #25 (Vol. 2 pp. 256-257), Pacificorp says their selection of CSS \u001Crelied upon high-level proxy costs in the economic modeling which needs to be validated by a front-end engineering design (FEED) study before advancing a carbon capture project\u001D which \u001Cwill evaluate an option for transport and storage of the CO2.\u001D Public estimates for the cost of storing or transporting CO2 suggest a range of under $5 to over $20 per metric ton. Capital Cost: Page 140 states that \u001CThe National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB) was used as much as possible to maintain consistency.\u001D However, the values in the supply-side resource data summary (see Data Support) do not match the values in the 2024 ATB, and the IRP does not describe how the values from NREL were adjusted. For example, CCS retrofits and large-scale solar capital costs are more than 20% cheaper than NREL, while capital costs for wind are consistently significantly higher than NREL estimates \u0013 more than 60% higher in the case of offshore wind.  Biodiesel: The 2025 Draft IRP introduces biodiesel as the assumed non-emitting fuel source for new peaking plants and

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as an alternative fuel source to transition gas and dual-fuel resources. However, there is no discussion about the cost and availability of biodiesel as a fuel. According to the EIA (See Data Support), there are no biodiesel production plants in Idaho, Wyoming, or Utah, where many of the plants that PAC assumes can transition to biodiesel are located.

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**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.
1. Example for CCS storage & transportation costs: https://www.globalccsinstitute.com/wp-content/uploads/2022/03/CCE-CCS-Technology-Readiness-and-Costs-22-1.pdf; 2. SSR Database available at: https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2025-irp/2025-irp-support-studies/Public_SSR_Database_Summary_Tab_2025.xlsx; 3. EIA Biodiesel Plant Production Capacity: https://www.eia.gov/biofuels/biodiesel/capacity/

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**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.
CCS 1: We recommend that PacifiCorp use a placeholder value for the cost of transporting or storing carbon captured in CCS retrofits. A cost of $10 per metric tonne of CO2 would result in an additional $13/MWh in variable operating costs for CCS at Jim Bridger, which could have a significant impact on its selection in the IRP.  CCS 2: We recommend that PacifiCorp specify their assumptions about carbon storage or utilization as it relates to tax credit qualification - for example, geologic sequestration qualifies for a much higher tax credit than using carbon for enhanced oil recovery. CCS 3: We also recommend that the FEED study mentioned in PacifiCorp\u0019s response to Stakeholder Feedback Form #25 be included in their action plan, to be completed prior to any commitments to the construction of CSS at Jim Bridger.  Capital Cost: We request that PacifiCorp describe in detail how NREL ATB values were adapted and adjusted to arrive at the values visible in the public SSR database. In particular, we recommend that PacifiCorp include inputs beyond NREL ATB used for small-scale wind, large-scale wind, offshore wind, large-scale solar, coal & gas CCS retrofits, and nuclear.   Biodiesel 1: We request that PacifiCorp specify the cost and availability assumptions that PacifiCorp uses for biodiesel in the 2025 IRP.  Biodiesel 2: We recommend that PacifiCorp assess what biodiesel transportation infrastructure would be required make the transition it models in the IRP, and perform a sensitivity analysis on the resulting fuel price impact.

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**PacifiCorp Response (3/17/25)**
**CCS 1 –** PacifiCorp does model transportation and sequestration as a cost related to the CCS units. This is modeled as a fixed cost as the infrastructure would need to be built and maintained regardless of the volume of CO2 captured.
**CCS 2 –** PacifiCorp has stated in the past, and will clarify in the IRP document, that the tax credit assumes the highest level of tax credit for CCS use, which as stated in this form is the geologic sequestration credit.
**CCS 3 –** Thank you for this feedback.

**Capital Costs –** Most of the supply-side resource options rely on the ATB and EIA reports. Some resources contained in the SSR tables are not listed in the ATB, but were developed through other reports, conversations with industry experts, developers and original equipment manufacturers (OEM's). CCS cost estimates are not based on the ATB, but on estimates specific to PacifiCorp plants. Wind and solar costs may vary from high-level ATB cost estimates based on year of construction, interconnection costs, locational modifiers, proprietary overhead and owners' costs, and node-specific meteorological assumptions. Additional information will be provided in Chapter 7 of the final 2025 IRP to be filed March 31, 2025.

**Biodiesel 1 –** PacifiCorp's biodiesel costs are derived from the U.S. Department of Energy's April 2024 edition of the Clean Cities and Communities Alternative Fuel Price Report, available online at:
https://afdc.energy.gov/files/u/publication/alternative_fuel_price_report_april_2024.pdf?2d6513fb43

Specifically, PacifiCorp is using the average of the West Cost pricing for biodiesel in Table 11 ($5.86/gal), and the California pricing for renewable diesel stated on page 20 (also shown in Figure 16), ($5.36/gal). This equates to

* Required fields

approximately $43/MMBTU and is assumed to escalate at inflation. At this price, demand is projected to be limited. PacifiCorp estimates that approximately three tanker trucks would be necessary to completely fill the tank storage for the 20 MW peaking resource. At this scale, PacifiCorp expects the same transportation infrastructure used for retail fueling stations would be used, and notes that retail rather than wholesale pricing has been applied, so it includes delivery costs.

**Biodiesel 2 –** The cost to transport Biodiesel to a site is included in the cost of the fuel. Additionally, unit specific retrofit and build costs include projected storage costs for this fuel type.

Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com

Thank you for participating.

# PacifiCorp - Stakeholder Feedback Form

Integrated Resource Plan

PacifiCorp (the Company) requests that stakeholders provide feedback to the Company upon the conclusion of each public input meeting and/or stakeholder conference call, as scheduled. PacifiCorp values the input of its active and engaged stakeholder group, and stakeholder feedback is critical to the IRP public input process. PacifiCorp requests that stakeholders provide comments using this form, which will allow the Company to more easily review and summarize comments by topic and to readily identify specific recommendations, if any, being provided. Information collected will be used to better inform issues included in the IRP, including, but not limited to the process, assumptions, and analysis. In order to maintain open communication and provide the broader Stakeholder community with useful information, the Company will post appropriate feedback on the IRP website based on your selection below.

Date of Submittal 2025-02-06


*Name: Katie Chamberlain

Title:

*E-mail: katherine@renewablenw.org

Phone:

*Organization: Renewable Northwest

Address:

City: State: Zip:


Public Meeting Date comments address: 01-22-2025

☒ Check here if related to specific meeting

List additional organization attendees at cited meeting:

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.
Procurement, transmission, price-policy scenarios, market reliance, emissions reductions

☒ Check here if you want your Stakeholder feedback and accompanying materials posted to the IRP website.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.
RNW seeks additional information on the draft 2025 IRP regarding procurement, transmission, price-policy scenarios, market reliance, and emissions reductions. Procurement: At various points in the draft IRP, PacifiCorp provides information on resources that are coming online in the near term. Can PacifiCorp provide a comprehensive list of resources it has contracted for that were submitted as bids into either the 2020 all-source RFP or the 2022 all-source RFP? Please include the name of the project, resource type, MW size, contracted year, expected COD, and the RFP or other source from which they came. Transmission: PacifiCorp states that B2H is no longer included in the preferred portfolio: \u001C[N]ote, at this time, 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\u001D (p.5). Can PacifiCorp provide more details around its reevaluation of B2H? Why was it not selected in the preferred portfolio as it has been in the last several IRP cycles? Given that PacifCorp jointly owns the line with Idaho Power, what does this mean for the project and for Idaho Power moving forward? Is PacifiCorp still contributing financially to the development of B2H? Doe\u0019s PacifiCorp\u0019s position have implications on future requests for cost recovery and sharing costs with Idaho Power? Price-policy scenarios: On page 175 of the draft IRP, PacifiCorp explains that the IRP contains five distinct price-policy scenarios: medium gas / existing federal regulations (MR), medium gas / zero CO2 (MN), high gas / high CO2 (HH), low gas / zero CO2 (LN), and medium gas / SCGHG (SC). In tables 9.30-9.33, PacifiCorp presents the cost and risk results of the initial and variant cases under four of the five price-policy scenarios, excluding the MR case. Why did the company not include a similar table with initial and variant cases under the MR case? In table 9.33, why did the company not include the integrated base MR case for comparison against the other cases? In tables

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9.30-9.32, the integrated base MR case performs well across these price policy scenarios - consistently ranking 1st or 2nd in both the PVRR assessment and CO2 emissions assessment. Please confirm our understanding of what this means: the MR case performs best in terms of being low cost and low risk across the majority of future price policy scenarios. Meanwhile, the preferred portfolio (MN case) does not perform as well across different price-policy scenarios and ranks next to last on emissions risk in the expected case. PacifiCorp states that \u001Cthe only variant cases which would be compliant under the current language in EPA 111(d) are the MR case and the No Coal Post 2032 case\u001D (p.249). Please confirm that by selecting the MN case as the preferred portfolio, PacifiCorp is not planning to comply with existing federal regulations.   Market reliance: In the January 22-23 public input meeting on the draft IRP, PacifiCorp explained that the model treats market purchases for capacity and energy differently. Market purchases are excluded during high-risk hours for the top five risk days per month for both the summer and winter seasons. However, the model allows the company to make market purchases for energy needs up to their economic limit. Has PacifiCorp attempted to quantify energy availability for the 2025 IRP? Can the company run a scenario/sensitivity for the final 2025 IRP where markets are tighter than expected from an energy perspective?  Emissions reductions: Figure 9.12 shows Oregon allocated emissions reductions relative to HB 2021 targets. Please explain the difference between the \u00182025 IRP w/o spec. sales\u0019 line and the \u00182025 IRP w/ spec. sales\u0019 line.

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**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.

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**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.

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**PacifiCorp Response (3/17/25):**

**Procurement –** Thank you for this suggestion. To the extent practicable based on any confidentiality agreements, PacifiCorp will seek to incorporate this information into the IRP narrative.
**Transmission –** B2H as a transmission project is not eligible for endogenous selection in the 2025 IRP. PacifiCorp's use case for this transmission investment has evolved. At present, the transmission line is needed to facilitate load service for certain large new loads. As has been previously communicated, PacifiCorp is evaluating transmission and resource needs for these large new loads outside of the traditional planning process, and with removal of these loads from the load forecast in the IRP, the associated transmission is also being removed. In previous IRP cycles, B2H would facilitate existing load growth via a redirect of existing transmission rights on Bonneville Power Administration's (BPA) system. PacifiCorp has not been successful in getting this redirect of transmission rights granted by BPA. Special contracts with large new load customers will drive cost recovery. This has not changed PacifiCorp's partnership with Idaho Power.
**Price-Policies –** Thank you for your feedback. The initial view of the MR case was that it ultimately applied only to the UIWC jurisdiction, given that the impact is primarily on units in which Oregon and Washington can no longer participate after 2030. With testing, the IRP team realized that Oregon and Washington jurisdictional initial selections would in fact be impacted by restrictions. The MR portfolio that will be presented in the final IRP will be different than the draft version, and the analysis above has not yet been completed on updated portfolios. Regarding table 9.33, the ST run of the MR portfolio under an SCGHG future pricing condition was not completed when the draft portfolio was published. A similar table was not contemplated for the MR price policy scenario because if a portfolio was NOT MR compliant, it could not be compared, and there was only 1 additional MR compliant portfolio. PacifiCorp plans to require one to two additional variants to be compliant under MR for the final filing. Given the timing of compliance, if current federal rules were to be upheld, PacifiCorp would further evaluate the various conversion and closure options as indicated by the final MR case.
**Market Reliance –** A low or no purchase sensitivity has not yet been contemplated. If time allows, PacifiCorp is willing to evaluate the preferred portfolio in an environment where purchases are limited further.
**Emissions –** The graph referenced is going to be updated for the final filing. The view presented demonstrates that Oregon allocated resources provide sufficient energy to meet its load on an annual basis, but that some emitting resources

* Required fields

allocated to Oregon were dispatched because it was economic to do so. The "with specified sales" line on this graph demonstrates that Oregon could dispatch gas resources when it is economic to do so, sell these resources to another jurisdiction, and still have enough allocated energy to meet Oregon load. PacifiCorp believes that this may be counter to current DEQ methodology for emissions reporting and as a result will be dispatching the final preferred portfolio to be compliant with Oregon emissions limits, which will limit natural gas-fired generation and economic benefits.

Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com

Thank you for participating.

* Required fields

# PacifiCorp - Stakeholder Feedback Form

## Integrated Resource Plan

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Date of Submittal 2/7/2025

*Name: Benedikt Springer Title:

*E-mail: benedikt.springer@puc.oregon.gov Phone:

*Organization: Oregon Public Utility Commission

Address:

City: State: Zip:

Public Meeting Date comments address: 1/22-23/2025 ☐ Check here if related to specific meeting

List additional organization attendees at cited meeting:

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.
Feedback on Draft 2025 IRP

x Check here if you want your Stakeholder feedback and accompanying materials posted to the IRP website.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.

- Staff appreciates that the IRP shows compliance with HB 2021, but it's unclear what planning changes resulted in the associated emission reductions. Please explain what actions or drivers are resulting in the change in GHG emissions between the 2023 IRP update and the 2025 IPR draft. Please ensure this is fully explained in the final IRP.

- Please explain whether Oregon HB 2021 emission targets are a binding constraint for the modeling of system resource additions and dispatch. What happens to existing resources in jurisdictional portfolios?

- What does "compliance can be achieved through economic specified-source wholesale sales of a portion of the excess supply, where the purchaser is responsible for the associated emissions" mean exactly?

- To which degree does Oregon carbon emission compliance rely on situs vs. system resources, what assumptions were made about resource sharing (including in terms of dispatch)?

- What are the costs and development assumptions associated with the off-take agreement for the Natrium Demonstration Project, and how are they reflected in the modeling?

- What is the full suite of characteristics assumed for the four non-CO2-emitting thermal resources (nuclear, small renewable fuel peaking, geothermal, and non-emitting hydrogen peaking) and in what ways are these emerging technology resources considered differently than resources for which attributes are well, or at least better known?

- What is meant by action item 1h? This is not mentioned anywhere else in the document. Please explain what "changes in accounting and/or dispatch of existing natural gas resources" specifically entails, the extent to which HB 2021

* Required fields

emission reductions are dependent upon these changes, and the specific Natural Gas Emissions Compliance obligations the Company is considering.

• How does the Company model compliance with the EPA GHG emission rules? Why did the Company select the MN portfolio as the preferred portfolio, especially when potentially cheaper options with lower emissions are available (MR)?

• Given the rapidly changing federal policy environment, does the Company anticipate making any changes to the IRP and its associated modeling to reflect environmental policy under a Trump administration?

• Tables 9.2, 9.3, and 9.4 omit existing resource options. How are jurisdictional shares of existing resources modeled and to those similarly comply with jurisdictional rules?

• Explain in more detail the steps used and the underlying logic of creating jurisdictional portfolios and integrating them into a system-wide portfolio. Explain what the Company's method implies about state-specific ownership of resources, and how the capacity/energy of those resources can be dispatched by the model. Furthermore, explain common alternative methodologies for allocating resources to jurisdictions and describe why PAC's choice is the preferred method and what tradeoffs it presents.

• Explain how sensitive IRP modeling results, including resource selections, are to changes in the MSP.

• Add a more detailed section on compliance with Oregon emissions rules. Explain how emission compliance is achieved and under which conditions emissions might deviate.
PacifiCorp response:

• New Resource actions should be further explicated. Explain how much new resources the Company is planning to acquire on what schedule.

• Assumptions vs. outcomes need to be better differentiated. For instance, the draft document makes it sound like the Natrium reactor was chosen by the model as the least-cost/least-risk option. However, during the public input meeting Staff learned that the acquisition of the Natrium reactor was added to the model as an a priori assumption.

PacifiCorp Response: Natrium was endogenously selected by the model as part of the least-cost, least-risk portfolio. At the January public input meeting, PacifiCorp explained that no costs associated with Natrium were included in the modeling process given that the Company has not yet reached an agreement with Terra Power.

• Explain the Company's natural gas dispatch strategy in Oregon.

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**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.

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**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.

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Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com

Thank you for participating.

**PacifiCorp Responses (3/17/2025):**

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- Staff appreciates that the IRP shows compliance with HB 2021, but it's unclear what planning changes resulted in the associated emission reductions. Please explain what actions or drivers are resulting in the change in GHG emissions between the 2023 IRP update and the 2025 IPR draft. Please ensure this is fully explained in the final IRP.

  **PacifiCorp Response**: In the 2025 IRP Draft, three modeling changes contributed to the emissions reductions:
  1. A model driver dispatch price was applied to each ton of Oregon-allocated emissions produced between 2030 and 2040 to incentivize the model to reduce emitting generation and to build additional clean resources.
  2. No gas plants or market purchases were allocated to Oregon after the end of 2039.
  3. Some emitting Oregon-allocated generation produced in excess of Oregon load was treated as a specified sale and was not counted towards the HB2021 emissions reduction targets. Further details were presented at the February public input meeting.

- Please explain whether Oregon HB 2021 emission targets are a binding constraint for the modeling of system resource additions and dispatch. What happens to existing resources in jurisdictional portfolios?

  **PacifiCorp Response**: In the 2025 IRP Draft, HB 2021 emission targets were not modeled as a binding constraint in PLEXOS. Instead, the Oregon jurisdictional portfolio includes a driver to incentivize clean energy production (on a $/MWh basis) and a second driver to disincentivize emissions from Oregon-allocated emitting resources (in proportion with their emissions factor in metric tonnes per MWh).

- What does "compliance can be achieved through economic specified-source wholesale sales of a portion of the excess supply, where the purchaser is responsible for the associated emissions" mean exactly?

  **PacifiCorp Response:** Imagine that we lined up every MWh of Oregon-allocated generation in a given year against every MWh of Oregon load in that year. Each MWh of Oregon-allocated generation that is not matched to a MWh of Oregon load is not necessary to meet Oregon compliance on an annual basis. The PLEXOS Short-Term (ST) dispatch model does not see that this MWh of generation is in excess of Oregon load. In the 2025 IRP Draft, the Company removed some emitting generation allocated to Oregon in excess of Oregon's annual load after viewing the results of economic dispatch in the ST model. In response to stakeholders, the Company will demonstrate compliance in the final 2025 IRP solely within the ST model using a model driver dispatch price.

- To which degree does Oregon carbon emission compliance rely on situs vs. system resources, what assumptions were made about resource sharing (including in terms of dispatch)?

  **PacifiCorp Response:** Existing, non-Qualifying Facility (QF) resources were allocated according to System Generation (SG) factors except for coal, which was not allocated to Washington or Oregon after the dates those states have elected to exit coal. After 2040, no gas was allocated to Oregon given the required 100% reduction in emissions set by HB2021. From 2030-2039, existing gas plants were allocated to Oregon based on SG factors. To enable Oregon compliance with HB2021 during 2030-2039, Oregon's share of each natural gas resource was modeled separately from the share allocated to other states, i.e. as two resources that can dispatch independently. Emissions cost drivers and emissions accounting for HB2021 compliance are based only on the Oregon-allocated resource.

- What are the costs and development assumptions associated with the off-take agreement for the Natrium Demonstration Project, and how are they reflected in the modeling?

  **PacifiCorp Response:** No costs associated with Natrium are modeled in the 2025 IRP, given federal funding and customer protection assumptions. At this time no agreement has been reached between TerraPower and the Company. There is no current off-take agreement. To the extent PacifiCorp commits to off-taking the output of Natrium, customer protections will be maintained. Natrium is modeled as selectable for each jurisdiction and is dispatched on a system-wide basis. Note that in the 2025 IRP Draft, it was assumed that Natrium was available January 1st, 2030. In the final 2025 IRP, it is assumed that Natrium is available January 1st, 2032.

- What is the full suite of characteristics assumed for the four non-CO2-emitting thermal resources (nuclear, small renewable fuel peaking, geothermal, and non-emitting hydrogen peaking) and in what ways are these emerging technology resources considered differently than resources for which attributes are well, or at least better known?

    **PacifiCorp Response**: Details regarding the modeling of nuclear, renewable peaking, geothermal, and hydrogen peaking are included in the supply side tables in Chapter 7 of the 2025 IRP Draft. These resources are not considered differently than other resources.

- What is meant by action item 1h? This is not mentioned anywhere else in the document. Please explain what "changes in accounting and/or dispatch of existing natural gas resources" specifically entails, the extent to which HB 2021 emission reductions are dependent upon these changes, and the specific Natural Gas Emissions Compliance obligations the Company is considering.

    **PacifiCorp Response:** In the 2025 IRP, Oregon's share of existing gas plants and some gas conversions are modeled as distinct units that dispatch separately from the rest-of-system share of these units. Given the need to reduce emissions to comply with HB2021, the units representing Oregon's share of gas plants have significantly lower generation than the rest-of-system units.

    The emission reductions modeled in the 2025 IRP are not dependent on changes in accounting or dispatch of existing natural gas resources. The following strategies could address action item 1h:

    - New resources – additional clean generation can reduce the frequency of gas-fired generation dispatch.
    - Allocation – Oregon could potentially exit a portion of its gas-fired generation ahead of 2040.
    - Market Dispatch – to manage its emissions requirements, Oregon's natural gas-fired generation may not be offered to the market or may have restricted availability. This may be difficult to coordinate if Oregon is allocated only a portion of a resource.
    - Market Design – HB2021 compliance is based on the emissions of generation used to serve Oregon consumers. Specified sales of emitting resources to other entities that assume responsibility for the associated emissions could provide economic benefits and support regional reliability. Similarly, specified purchases of low or zero-emitting resources could reduce emissions relative to unspecified market purchases. Exactly how this would work in the market and in compliance reporting has not yet been determined.

- How does the Company model compliance with the EPA GHG emission rules? Why did the Company select the MN portfolio as the preferred portfolio, especially when potentially cheaper options with lower emissions are available (MR)?

    **PacifiCorp Response**: In the integrated MR portfolio, compliance with the Environmental Protection Agency's (EPA) rule 111(d) is modeled by forcing all coal plants to either:

    - Cease coal-fired operation and convert to lower-emitting fuel by January 1, 2030;
    - Retire by January 1st, 2032; or
    - Install carbon capture and sequestration (CCS) technology or cease coal-fired operation

    In addition, the maximum allowed capacity factor for any new natural gas fired resource that is endogenously selected by the model is 40%. The Company selected the MN portfolio as the draft preferred portfolio because it was the least cost portfolio under the MN price-policy scenario but recognizes that the draft did not include complete price-policy results or stochastic results that could have influenced the portfolio outcomes.

- Given the rapidly changing federal policy environment, does the Company anticipate making any changes to the IRP and its associated modeling to reflect environmental policy under a Trump administration?

    **PacifiCorp Response:** The Company does not currently plan to make any changes to its modeling to reflect possible new federal policies. As in the 2025 Draft, the Company will produce a sensitivity with lowered production tax credits and investment tax credits.

- Tables 9.2, 9.3, and 9.4 omit existing resource options. How are jurisdictional shares of existing resources modeled and to those similarly comply with jurisdictional rules?

**PacifiCorp Response:** Except for coal, and gas, which are removed from those states whose policy requires it and reallocated among the remaining states, existing resources are modeled as system resources, with allocation aligned the 2020 Protocol (and via the Washington Inter-Jurisdictional Allocation Methodology or "WIJAM", for Washington).

- Explain in more detail the steps used and the underlying logic of creating jurisdictional portfolios and integrating them into a system-wide portfolio. Explain what the Company's method implies about state-specific ownership of resources, and how the capacity/energy of those resources can be dispatched by the model. Furthermore, explain common alternative methodologies for allocating resources to jurisdictions and describe why PAC's choice is the preferred method and what tradeoffs it presents.

**PacifiCorp Response:**

The essential logic of the jurisdictional portfolio selection and integration in the 2025 Draft is as follows:

- **Jurisdictional Studies:** All three jurisdictional studies are prepared using the same essential inputs, though with adjustments where necessary. A separate jurisdictional study is prepared for each variant and price-policy scenario (although Washington's jurisdictional study always uses the social cost of greenhouse gases). For the 2025 Draft, this initial step assumed 100% allocation of all proxy resource selections – this identifies the most cost-effective resources and results in fewer overall selections than a partial allocation (under Oregon's ~30% allocation, more than 3x as many resources would be needed, whereas under Washington's ~8% allocation, more than 12x as many resources would be needed).
- **Integrated Portfolio:** In general, the integration logic takes the *maximum* of the cumulative builds in each of the jurisdictional portfolios, for each individual resource that is selected in any of the portfolios.
    - Resources allocated to one jurisdiction ignore the selections by other jurisdictions. For example, energy efficiency is always based on the results specific to its own jurisdiction. Similarly, coal resource selections are based on the Utah/Idaho/Wyoming/California jurisdictional portfolio.
    - Because of the tie to the underlying asset, brownfield or surplus interconnection resource selections at coal plants are also tied to the Utah/Idaho/Wyoming/California jurisdictional portfolio.
- **Resource allocations:** The "max of resources" logic described above is not inherently dependent on allocations. Sharing a resource among the jurisdictions in which it was selected and shown to be cost-effective reduces the amount available to be allocated to each of those jurisdictions. In the 2025 Draft IRP, allocations were based on the jurisdiction that first identified an incremental resource addition – if one jurisdiction adds resources in 2028 while a second adds resources in 2030, the first jurisdiction would get all of the 2028 resources while second would only get incremental additions in 2030 to the extent they exceed the 2028 level. When resources are selected in all of the jurisdictions at the same time, allocation was based on their system load factors (SG share).
- **Additional resource selections:** if the integrated portfolio is not compliant for a particular jurisdiction due to allocations, the jurisdictional portfolio can be rerun in one of two ways: add the compliance shortfall to the target (so the model selects more), or reduce the assumed allocation of proxy resources (so the model gets less credit for each, and selects more).

The intent of the jurisdictional methodology is to ensure that proxy selections are cost-effective using jurisdiction-specific compliance obligations and planning assumptions. These planning assumptions are mutually exclusive, for example Washington requires that the social cost of greenhouse gas be used in resource dispatch, while recently Oregon has directed that potential future carbon policies be excluded from resource dispatch. On the other hand, the 2025 Draft results indicate that Oregon and Washington have many overlapping resource selections. This is particularly true if selections are limited to resources on the West side of PacifiCorp's system which have greater likelihood of being deliverable to Oregon and Washington customer loads. With that in mind PacifiCorp is exploring allocation of west-side resource selections based on west-side load shares (Control Area Generation – West, i.e. CAGW from the 2020 Protocol). Because the IRP deals with proxy resources, rather than specific alternatives, it is more important to consider overall quantities than the assumed allocation and this CAGW treatment. The IRP is not equipped to distinguish whether Oregon and Washington take a CAGW share of each and every west-side resource option or situs shares of specific resources totaling the same level, but these remain important and necessary considerations as part of actual procurement.

Please refer to the company's materials and discussion in its public input meeting series. Also, please refer to the discussion of modeling strategy presented in Chapters 8 and 9 of the Draft 2025 IRP and the final 2025 IRP to be filed March 31, 2025.

- Explain how sensitive IRP modeling results, including resource selections, are to changes in the MSP.

  **PacifiCorp Response:** Any change to agreed-upon allocations can impact IRP model drivers, post-model compliance assessments, and iterative resource selections to ensure compliance in competitive portfolios. A larger share of existing clean resources would reduce the need for new resources to serve Oregon customers, and vice versa.

- Add a more detailed section on compliance with Oregon emissions rules. Explain how emission compliance is achieved and under which conditions emissions might deviate.

  **PacifiCorp Response:** An appendix in the final 2025 IRP will include details regarding Oregon emissions compliance.

- New Resource actions should be further explicated. Explain how much new resources the Company is planning to acquire on what schedule.

  **PacifiCorp Response**: The Company appreciates Staff's desire for more specific details regarding future resource acquisitions and will consider ways to incorporate them into the final 2025 IRP. The final IRP action plan will include additional details regarding the pursuit of resources as indicated in the preferred portfolio.

- Assumptions vs. outcomes need to be better differentiated. For instance, the draft document makes it sound like the Natrium reactor was chosen by the model as the least-cost/least-risk option. However, during the public input meeting Staff learned that the acquisition of the Natrium reactor was added to the model as an a priori assumption.

  **PacifiCorp Response**: Natrium was endogenously selected by the model as part of the least-cost, least-risk portfolio, inclusive of customer protections and federal funding for this unique project. PacifiCorp has not yet reached a contractual agreement with Terra Power (per the Draft 2025 IRP Chapter 10, pages 259 and 265). The final 2025 IRP will include a nuclear counterfactual study and alternative path analysis.

- Explain the Company's natural gas dispatch strategy in Oregon.

  **PacifiCorp Response**: In the Draft 2025 IRP, Oregon's jurisdictional portfolio results indicate that existing natural gas plants remain a cost-effective source of capacity for the Western Resource Adequacy Program (WRAP) in 2030. How Oregon should transition away from natural gas by 2040 remains to be determined. The degree to which gas units remain valuable for Oregon is influenced by their impact on emissions compliance. Natural gas plants generally dispatch when their variable costs are lower than market, lowering the cost of serving load during expensive market conditions. Combined cycle plants also have lower emission rates than unspecified market purchases and can serve more load for a given quantity of emissions.

  For the 2025 IRP, PacifiCorp has broken each natural gas plant into Oregon and non-Oregon shares and has allowed the shares to dispatch independently. The Oregon share counts toward Oregon's WRAP and emissions compliance requirements, while the non-Oregon share can dispatch without impacting Oregon's emissions compliance requirements. In actual operations, PacifiCorp has dispatch agreements for jointly owned units including Jim Bridger (shared with Idaho Power). These agreements work best when the units are flexible (e.g., low startup costs or low minimum operating level as a percentage of nameplate) and the joint owners are generally aligned regarding when a unit should be online or offline. Sharing of combined cycles is more complex, due to startup costs, relatively high minimum operating levels, and run-time and startup impacts on maintenance requirements. Sharing can still be possible in special circumstances, as with PacifiCorp's 50% share of the Hermiston natural gas plant, which consists of two comparable units, and PacifiCorp and its co-owner each independently control one unit at a given time. It is likely HB2021 compliance will drive Oregon to reduce natural gas plant dispatch relative to other jurisdictions, so independent control of emitting resources is likely to be necessary. That could include consolidation in particular units, or some form of joint dispatch arrangement. This would require coordinated electricity market decisions in order to manage the emissions impact associated with unspecified market purchases.

Natural gas capacity may need to be dispatched in WRAP for regional reliability needs, it could also be dispatched in the Enhanced Day-Ahead Market (EDAM) for regional requirements (if/when it is made available to the market). Depending on the structure of the market and the resource allocation methodology, the generation and emissions associated with market dispatches might not be considered part of the resources used to serve Oregon's load. While such processes have not yet been developed, reduced control over resource dispatch (and the resulting emissions) will reduce the economic benefits of natural gas plants for Oregon customers as HB2021 compliance requirements tighten over time.

* Required fields

# PacifiCorp - Stakeholder Feedback Form

## 2025 Integrated Resource Plan

PacifiCorp (the Company) requests that stakeholders provide feedback to the Company upon the conclusion of each public input meeting and/or stakeholder conference calls, as scheduled. PacifiCorp values the input of its active and engaged stakeholder group, and stakeholder feedback is critical to the IRP public input process. PacifiCorp requests that stakeholders provide comments using this form, which will allow the Company to more easily review and summarize comments by topic and to readily identify specific recommendations, if any, being provided. Information collected will be used to better inform issues included in the 2025 IRP, including, but not limited to the process, assumptions, and analysis. In order to maintain open communication and provide the broader Stakeholder community with useful information, the Company will generally post all appropriate feedback on the IRP website unless you request otherwise, below.

Date of Submittal: 2/20/2025


*Name: Rose Monahan, Staff Attorney
Matt Gerhart, Senior Attorney

Title:

*E-mail: Rose.monahan@sierraclub.org
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*Organization: Sierra Club

Address: 2101 Webster Street, Suite 1300

City: Oakland State: CA Zip: 94612


Public Meeting Date comments address: 1/22-23/2025 ☐ Check here if not related to specific meeting

List additional organization attendees at cited meeting:

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***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.

- Feedback on Draft 2025 IRP

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☐ Check here if you do **not** want your Stakeholder feedback and accompanying materials posted to the IRP website.

---

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.

**IRP Topic: Early Deployment Resources**

Sierra Club is concerned that there is a mismatch between PacifiCorp's previous cancellation of its 2022 All-Source RFP and assumptions regarding the earliest date for commercial operation of certain resource types. Some of the projects being considered for the 2022 RFP were under development for several years and likely still exist in some form. These could potentially be completed in a more expedited manner. While bid pricing may need to be updated, these projects would not need to wait for a subsequent procurement cycle to be completed. As such, it does not make sense to push out the earliest practicable date for *all* new greenfield solar, wind, and storage projects if some projects could be brought online sooner.

Sierra Club recommends that PacifiCorp conduct a sensitivity that includes a commercial operation date of 2026 for an initial tranche of solar, wind, and battery storage resources that equate to the 2022 AS RFP. This sensitivity should also employ the modified PTC inputs discussed in response to Utah Clean Energy's 2/10/2025 feedback form.

**IRP Topic: PLEXOS Input Files**

Sierra Club requests that upon filing the 2025 IRP that the Company also provide (upon request and subject to applicable non-disclosure agreements) the specific PLEXOS input files in XML format used to conduct its modeling. This would allow stakeholders to validate PacifiCorp's model results and conduct their own sensitivity analyses. It would also be consistent with the approach taken by many states as part of their IRP process to provide model data and licenses to intervenors including Arizona, New Mexico, Michigan, North Carolina, and Georgia. In fact, the Oregon PUC adopted a similar requirement for PacifiCorp as part of Order 20-392 in the 2021 TAM proceeding (Docket No. UE 375): "PacifiCorp will provide AURORA licenses to Commission Staff and intervenors for each future TAM. PacifiCorp will provide all inputs, data, model settings, constraints, and any other modeling changes. The costs of the licenses, training, and data sets will be included for cost recovery in any TAM until the next general rate case."

* Required fields

**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.

**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.

(1) Conduct a sensitivity that includes a commercial operation date of 2026 for an initial tranche of solar, wind, and battery storage resources that equate to the 2022 AS RFP;
(2) Provide, upon request and subject to the applicable non-disclosure agreements, the specific PLEXOS input files in XML format used to conduct the 2025 IRP modeling to requesting parties.

**PacifiCorp Response (3/17/2025):**

1. PacifiCorp is continually evaluating current opportunities to acquire resources. Given the results the IRP team has seen thus far, resources become less expensive over time due to the NREL ATB cost escalation curve. Resources acquired in 2026 would be modeled as higher cost than those acquired later. Additionally, WRAP compliance is not binding until 2028, and Oregon and Washington compliance is not binding until 2030. The optimal solution in this case is to procure resources as late as possible to avoid early years of higher build costs, levelized over the 21-year horizon. Providing the model with a 2026 COD is unlikely to result in additional resource procurement in 2026.

2. Pursuant to confidentiality agreements and any other required negotiations, PacifiCorp can provide this input data.

Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com
Thank you for participating.

* Required fields

# PacifiCorp - Stakeholder Feedback Form

## Integrated Resource Plan

PacifiCorp (the Company) requests that stakeholders provide feedback to the Company upon the conclusion of each public input meeting and/or stakeholder conference call, as scheduled. PacifiCorp values the input of its active and engaged stakeholder group, and stakeholder feedback is critical to the IRP public input process. PacifiCorp requests that stakeholders provide comments using this form, which will allow the Company to more easily review and summarize comments by topic and to readily identify specific recommendations, if any, being provided. Information collected will be used to better inform issues included in the IRP, including, but not limited to the process, assumptions, and analysis. In order to maintain open communication and provide the broader Stakeholder community with useful information, the Company will post appropriate feedback on the IRP website based on your selection below.

Date of Submittal 2025-03-03

*Name: Jeremy Rishe  Title:

*E-mail: jer270@nyu.edu  Phone: 3474509565

*Organization: Stock holder of Berkshire Hathawa

Address: 986 Sterling Place

City: Brooklyn  State:  Zip: 11213

Public Meeting Date comments address: 03-03-2025  ☐ Check here if related to specific meeting

List additional organization attendees at cited meeting:

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***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.
Solar

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☒ Check here if you want your Stakeholder feedback and accompanying materials posted to the IRP website.

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***Respondent Comment:** Please provide your feedback for each IRP topic listed above.
As a shareholder I wish it to be known that I am a proponent of using the natural power of the sun to energize our cities and homes. It's clean, it's always in the sky and therefore efficient. Pacific Corp would be wise to develope long term storage batteries for such a future, and update he grid to help deliver such energy with maximum effieincy.

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**Data Support:** If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.

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**Recommendations:** Provide any additional recommendations if not included above - specificity is greatly appreciated.

---

**PacifiCorp Response:**
Thank you for your feedback. PacifiCorp is exploring transmission investments as well as long duration storage to address these concerns, and the draft preferred portfolio contains significant long duration storage selections.

Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com

Thank you for participating.

* Required fields

# APPENDIX N – ENERGY STORAGE POTENTIAL EVALUATION

## Introduction

Energy storage resources can provide a wide range of grid services and can be flexibly sized and sited. Many of these grid services have been increasing in value with increasing penetration of variable energy resources such as wind and solar, while energy storage costs have been falling. As a result, storage resources are an increasing component of PacifiCorp's least-cost, least-risk preferred portfolio. While the IRP portfolio analysis captures the system benefits of energy storage, it does not fully account for localized benefits and siting opportunities. This appendix provides details on how energy storage resources can be configured to maximize the benefits they provide.

Because energy storage resources are highly flexible, with the ability to respond to dispatch signals and function as both a load and a resource, they can potentially provide any of the grid services discussed herein. Other types of resources, including distributed generation, energy efficiency, and interruptible loads can also provide one or more of these grid services, and can complement or provide lower-cost alternatives to energy storage. Given that broad applicability, Part 1 of this appendix first discusses a variety of grid services as generically and broadly as possible. Part 2 discusses the key operating parameters of energy storage and how those operating parameters relate to the grid services in Part 1. Finally, Part 3 discusses how to optimize the configuration and dispatch of energy storage and other distributed resources to maximize the benefits to the local grid and the system. Part 3 also provides examples of specific applications and examples of applications that may be cost-effective in the future.

## Part 1: Grid Services

PacifiCorp must ensure that sufficient energy is generated to meet retail customer demand at all times. It also must maintain resources that can respond to changing system conditions at short notice, these operating reserves are held in accordance with reliability standards established by the National Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC). Both energy and operating reserves are dispatch-based, and dependent on the specific conditions at a specific place and time. These values are generally independent from hour to hour, as removing a resource in a subset of hours may not impact the value in the remaining hours.

Because load can be higher than expected and some resources may be unavailable at any given time, sufficient generation resources are needed to ensure that energy and operating reserve requirements can be met with a high degree of confidence. This is referred to as generation capacity. The transfer of energy from the locations where it is generated to the locations where it is delivered to customers requires poles, wires, and transformers, and the capability of these assets is referred to as transmission and distribution (T&D) capacity. Generation and T&D capacity are both generally asset-based and provide value by allowing changes in the resources and T&D elements. In general, assets cannot be avoided based on changes to a subset of the hours in which they are needed, and only limited changes are possible once constructed or contracted. It should also be noted that the impact of asset or capacity changes on dispatch must also be included in any valuation.

These obligations are broken down into the following grid services, which are discussed in this section:

- Energy, including losses;
- Operating reserves, including:
    - Spinning reserve;
    - Non-spinning reserve;
    - Regulation and load following reserves; and
    - Frequency response;
- Transmission and distribution capacity; and
- Generation capacity.

## Energy Value

**Background**

Because PacifiCorp's load and resources must be always balanced, when an increment of generation is added to PacifiCorp's system, an increment of generation must also be removed. This could take the form of a generator that is backed down, an avoided market purchase, or an additional market sale. The cost of the increment that is removed (or the revenue from the sale), represents the energy value, and this value varies by location and by time. Location can also impact line losses relative to the generation which would otherwise have been dispatched, with losses manifesting as a larger effective volume. Regarding time, there are two relevant time scales: hourly values, and sub-hourly values.

The energy value in a location is dependent on PacifiCorp's load and resource balance, the dispatch cost of its resources, and the transmission capability connecting those resources to load. Differences in energy value occur when the economic resources in area exceed the transmission export capability to an area that must then use higher cost resources to serve load. Once transmission is fully utilized, the higher cost resources must be deployed to serve the importing area and lower cost resources will be available in the exporting area. As a result, the value in each location will reflect the marginal resources used to serve load in each area. If transfers are not fully utilized in either direction, the marginal resource in both areas would be the same, and the energy value would be the same.

Both load and resource availability change significantly across the day and across the year. Differences in value over time are driven by the cost of the marginal resource needed to serve load, which changes when load or resource availability change. When load goes up, or the supply of lower-cost resources goes down, the marginal resource needed to serve load will be more expensive.

The value by location is also dependent on the losses relative to the generation which would otherwise have been dispatched. Losses occur during the transfer of energy across the T&D system to a customer's location. As distance and voltage transformation increase, more generation must be injected to meet a customer's demand. For example, a distributed resource that is close to customer load or located on the same voltage level can avoid both energy at its location as well as the losses which otherwise would have occurred in delivering energy to that location. As a result, the marginal generation resource's output may be reduced by an amount greater than the metered output of a distributed resource. This increase in volume due to losses is also relevant to generation and T&D capacity value.

**Modeling**

There are two basic sources of energy values: market price forecasts and production cost models. There are also two relevant time scales: hourly values, and sub-hourly values.

PacifiCorp produces a non-confidential official forward price curve (OFPC) for the major market points in which it typically transacts on a quarterly basis. The OFPC represents the price at which power would be transacted today, for delivery in a future period. The OFPC contains prices for each month for heavy load hour (HLH) and light load hour (LLH) periods and goes forward approximately 20 years.[1] However, not all hours in the HLH or LLH periods have equal value. To differentiate between hours, PacifiCorp uses scalars calculated based on historical hourly results. For PacifiCorp's operations and production cost modeling, scalars are based on the California Independent System Operator's day-ahead hourly market prices. Because these values are used in operations, the details on the methodology and the resulting prices are treated confidentially. To allow for transparency, PacifiCorp has also developed non-confidential scalars using historical Western Energy Imbalance Market prices. With either scalar, the result is a forecast of hourly market prices that averages to the values in the OFPC over the course of a month. Using hourly market price to calculate energy value implies that market transactions are either the avoided resource, or a reasonable representation of the avoided resource's marginal cost in any given interval.

Production cost models contain a representation of an electric power system, including its load, resources, and transmission rights, as well as markets where power can be bought or sold. They also account for operating reserve obligations and the resources held to cover those obligations. All models are simplified representations, and there are several key simplifying assumptions. The granularity of a model is its smallest calculated timestep. While calculating twice as many timesteps should take roughly twice as long from a mechanical standpoint, evaluating decisions that span multiple time steps (such as when to charge or discharge a battery, or when to start or shutdown a thermal resource) requires the evaluation of multiple timesteps at once, resulting in a larger more complicated problem that can take longer to solve. In addition, maintaining inputs to represent smaller timesteps is more complicated, and a model is only as good as its inputs. To simplify the representation of location, transmission areas can be defined by the key transmission constraints which separate them, with transmission within each area assumed to be unconstrained. Another simplifying assumption is to model all load and resources at a level equivalent to generator input. For instance, load is "grossed up" from the metered volume to a level that includes the estimated losses necessary to serve it. This allows for a one for one relationship between all volumes, which vastly simplifies the model.

PacifiCorp's production cost modeling for the IRP uses the Plexos model and reflects system dispatch at an hourly granularity. While the IRP modeling uses the hourly market prices from the OFPC as inputs, a distributed resource's energy value will depend on its location and other characteristics and can be either higher or lower than the market price in a given hour. Generally, a resource's value is based on the difference between two production cost model studies: one with the resource included, and one with the resource excluded. This explicitly identifies the marginal

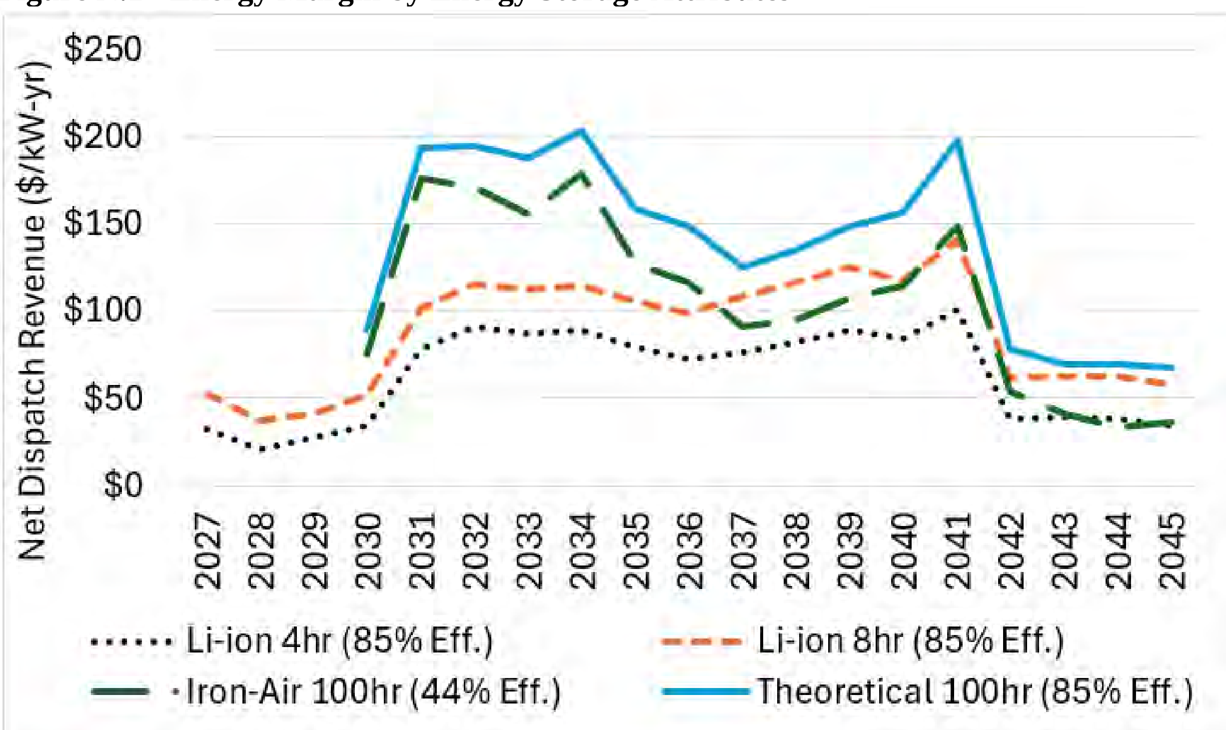
[1] HLH is 6:00 a.m. to 10:00 p.m. Pacific Prevailing Time Monday through Saturday, excluding NERC holidays. LLH is all other hours.

resources dispatched in the absence of the resource being evaluated. The Plexos model offers an alternative in that it reports the value of energy produced by each resource, by multiplying that resource's output by the marginal price in that resource's location for each hour. A comparable calculation is performed for operating reserves. This provides an estimate of the marginal benefits from any resource in the portfolio, without the need for with and without studies. However, for large resources or significant portfolio changes, with and without studies may still be necessary, as the reported results reflect the marginal cost of the last increment of generation, rather than the average across all the resource's output.

More detailed models of the electrical power system also exist, for instance PacifiCorp uses physical models for grid operations and planning that account for power flows and the loading of individual system elements. Similarly, the California Independent System Operator (CAISO) uses a "Full Network Model" with detailed representations of all resources and loads, as well as the transmission system. CAISO's model includes a representation of PacifiCorp's system for the purpose of dispatching resources in the Western Energy Imbalance Market (EIM), and models a five-minute granularity for that purpose. The added detail these physical models produce comes from a significant increase in the complexity of inputs and computational requirements.

Figure N.1 contains a sample of energy margin values for various combinations of energy storage specifications, and reflects marginal values reported by the Plexos model, including both energy and operating reserves.

**Figure N.1 - Energy Margin by Energy Storage Attributes**




These energy values will vary by location, volume, and operating reserve requirements, as well as with changes in the portfolio. Longer duration provides greater value, though it diminishes as more duration is added. As shown above, changes in efficiency also have an impact on dispatch revenue, notably because revenues are net of greater charging costs. Storage of all types benefits when marginal costs are negative, and the prevalence of PTC-eligible resources results in relatively high values in 2031-2041. In addition to declining value from PTCs, significant storage resource additions in 2042 result in higher marginal costs to charge the larger storage fleet and lower marginal benefits from discharging. These effects could be outweighed by a variety of factors including changes in renewable resources or load.

The Plexos model identifies resources to carry operating reserves for each hour but does not include the intra-hour changes that would cause those resources to be deployed. Because resources that are dispatchable within the hour can be dispatched up when marginal energy costs are high, and down when marginal energy costs are low, this can result in incremental value relative to an hourly market price or hourly production cost model result. In practice, sub-hourly dispatch benefits are largely derived from PacifiCorp's participation in EIM, and the specific rules associated with that market. For instance, resources must be participating in EIM to receive settlement payments based on their five-minute dispatches. Resources that are not participating receive settlement payments based on their hourly imbalance. Furthermore, because non-participating resources are not visible to the market, their sub-hourly dispatch would not impact the market solution. Because distributed resources can be aggregated for purposes of EIM participation, size should not be an impediment; however, the structure of the EIM may dictate some aspects of their use and would need to be aligned with the other services a distributed resource provides. While intra-hour dispatch is a key aspect of reliable system operation, and potentially an additional source of revenue for flexible resources, it is difficult to represent the interactions between hourly dispatch in Plexos and sub-hourly dispatch in EIM – since they have finite storage capability, a battery that is discharged in response to high prices in EIM is likely to forego dispatch at relatively high prices in a later interval. In addition, imbalance in the EIM is finite in both duration and magnitude and the battery resources added in PacifiCorp's preferred portfolio could easily move the market thereby drastically reducing the frequency of price excursions and the associated intra-hour revenue.

In addition to potential EIM revenue for intra-hour dispatch, dispatchable resources may receive additional revenue for their availability during day-ahead and hour-ahead market operations, for example as part of the Extended Day-Ahead Market (EDAM) being developed by the California Independent System Operator. Because the Plexos model has a single system dispatch solution for each hour, without day-ahead or hour-ahead resource commitments and uncertainty, the additional value associated with this type of uncertainty is not part of the reported results.

For these reasons, PacifiCorp has not quantified the costs or benefits of intra-hour dispatch for the 2025 IRP but expects to continue evaluating them as its portfolio and the market itself continue to evolve.

## Operating Reserve Value

### Background

Operating reserve is defined by NERC as "the capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection."[2] Operating reserves are capability that is not currently providing energy, but

[2] Glossary of Terms Used in NERC Reliability Standards: https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf, updated February 26, 2025.

which can be called upon at short notice in response to changes in load or resources. Operating reserves and energy are additive – a resource can provide both at the same time, but not with the same increment of its generating capability. Operating reserves can also be provided by interruptible loads, which have an effect comparable to incremental resources. Additional details on operating reserve requirements are provided in Volume II, Appendix F (Flexible Reserve Study).

As with energy value, operating reserve value is based on the marginal resource that would otherwise supply operating reserves, and varies by both location, time, and the speed of the response. Because operating reserve requirements are primarily applied at the Balancing Authority Area (BAA) level, the associated value is typically uniform within each of PacifiCorp's BAAs. An exception to this is that operating reserves must be deliverable to balance load or resources, so unused capability in a constrained bubble without additional export capability does not count toward the meeting the requirements. Operating reserve value is somewhat indirect in comparison to energy value, as it relates to the use of the freed-up capacity on units that would otherwise be holding reserves. If that resource's incremental energy is less expensive that what is currently dispatched, it can be dispatched up, and more expensive energy can be dispatched down. The value of the operating reserves in that instance is the margin between the freed-up energy and the resource that is dispatched down. Note that the dispatch price of the resource being evaluated does not impact the value, since holding operating reserves does not require dispatch. When the freed-up resource is more expensive than what is currently dispatched, it will not generate more when the operating reserve requirement is removed, and the value of operating reserves would be zero. Operating reserves are generally held on the resources with the highest dispatch price. Finally, operating reserve value is limited by the speed of the response: how fast a unit can ramp up in a specified period, and how soon it begins to respond after receiving a dispatch signal. Reliability standards require a range of operating reserve types, with response times ranging from seconds to thirty minutes.

**Modeling**

As discussed above, the value of incremental operating reserves is equal to the positive margin between the dispatch cost of the lowest cost resource that was being held for reserve, and the dispatch cost of the highest cost resource that was dispatched for energy. Similar to the value of energy, the price of different operating reserve types could be forecasted by hour, based on forecasts of reserve capability, demand, and resource dispatch costs. Given the range and variability in these components, this would be an involved calculation. In addition, because operating reserves are a small fraction of load, they are more sensitive to volume than energy. For instance, spinning reserve obligations are approximately three percent of load in each hour. As a result, resource additions may rapidly cover that portion of PacifiCorp's requirement met by resources that could otherwise provide economic generation and which produce a margin when released from reserve holding. This is particularly true for batteries and interruptible load resources that can respond rapidly and thus count all or most of their output toward reserve obligations.

While a market price for operating reserve products does not align well with PacifiCorp's system, the specifics of the calculation described above are embedded within PacifiCorp's production cost models. Those models allocate reserves first to energy limited resources in those periods where they could generate but are not scheduled to do so. Examples of energy limited resources include interruptible loads, hydro, and energy storage. If called on for reserves, these resources would lose the ability to generate in a different period, so the net effect on energy value for that resource is relatively small. As a result, the unused capacity on these resources can't be used for generation, but that also means it can count as reserves without forgoing any generation and incurring a cost to do so. After operating reserves have been fully allocated to the available energy-limited resources, reserves are allocated to the highest cost generators with reserve capability in the supply stack, up to each unit's reserve capability, until the entire requirement is met. This is generally done prior to generation dispatch and balancing because the requirements are input to the model or based on a formula and aren't typically restricted based on transmission availability. After the reserve allocations are complete, the remaining dispatch capability of each unit is used to develop an optimized balance of load and resources.

As part of the calculation of wind and solar integration costs reported in Volume II, Appendix F (Flexible Reserve Study), PacifiCorp assessed the cost of holding incremental operating reserves. That study identified a cost of approximately $8/kw-yr (2024$), based on a 2025-2045 study period. This value would be applicable to any resource that provided operating reserves uniformly throughout the year. Like reporting on energy values, the Plexos model also reports operating reserve revenues specific to each modeled resource, accounting for availability, location, and use for energy dispatch (during which a resource could not also provide reserves with any portion of its capacity that was generating energy). As with the annual wind and solar costs shown in Appendix F, operating reserve value is projected to be highest in the near term and decline across the study horizon as the amount of battery resources on the system increases.

## Transmission and Distribution Capacity

The IRP includes endogenous transmission upgrades as part of portfolio selection. This allows the cost of transmission upgrades to be considered as part of the modeled cost of resources in each area. However, because energy efficiency and load control are customer-sited, they are not subject to these constraints, placing them at an advantage relative to both thermal and renewable resource options. For some sizes and locations, distributed resources can also potentially avoid significant transmission upgrades and may help to defer distribution system investments. While the cost of specific T&D projects varies, a generic system wide estimate of transmission upgrade costs is included as a credit to energy efficiency in the 2025 IRP and amounts to $5.83/kw-year (2024$). In practice, these costs would vary by project and some transmission upgrades would not be suitable for deferral by distributed resources. Because of the large scale of many transmission upgrades, and the binary nature of the expenditures, it may be difficult to procure adequate distributed resources to cover the need in a timely fashion and in accordance with reliability requirements, though it is always appropriate to consider the available options when considering expenditures on an upgrade. Distribution capacity upgrades are more likely to be suitable for deferral by a distributed resource, as the scale of the need is closer to that of these types of resources.

To that end, PacifiCorp maintains an "Alternative Evaluation Tool" which is used to screen the list of projects identified during T&D planning to assess where distributed resources, including energy storage, could be both technically feasible and cost competitive as compared to traditional T&D solutions. If a study shows that distributed resource alternatives are feasible and potentially cost-competitive that project is flagged for detailed analysis.

## Generation Capacity

**Background**

To provide reliable service to customers, a utility must have sufficient resources in every hour to:

- Serve customer load, including losses and any unanticipated load increase.
- Hold operating reserves to meet NERC and WECC reliability standards, including contingency, regulation, and frequency response.
- Replace resources that are unavailable due to:
  - Forced and planned outages
  - Dry hydro conditions
  - Wind and solar conditions
  - Market conditions

PacifiCorp refers to "Generation Capacity" as the total quantity of resources necessary to reliably serve customers, after accounting for the items above. For the 2025 IRP, PacifiCorp is using planning reserve margins from the Western Resource Adequacy Program that vary by month and can range from 10-20% of the peak load in a given month. The planning reserve margin does not translate directly into either resources or need.

All resources contribute to a reliable portfolio, but they do so in ways that are not straightforward to measure and are dependent on the composition of the portfolio. Removing a resource from a portfolio will make that portfolio less reliable unless it is replaced with something else, ideally in a quantity that provides an equal capacity contribution and results in equivalent reliability. For more details on capacity contribution, please refer to Volume II, Appendix K (Capacity Contribution).

As a result, the most direct measurement of the generation capacity value of a resource is to build a portfolio that includes it and compare that portfolio to one without it. But even that analysis would identify more than just generation capacity value, as it would also include energy and operating reserve impacts related to both the resource being added and resources that were delayed or removed. This is an essential description of the steps used to develop portfolios in the IRP, and while powerful, the IRP models and tools do not lend themselves to ease of use, rapid turnaround, or the evaluation of small differences in portfolios.

As an alternative, a simplified approach to generation capacity value can be used when the resources being evaluated are small or like the proxy resource additions identified in the IRP preferred portfolio. The premise of the approach is that the IRP preferred portfolio resources represent the least-cost, least-risk path to reliably meet system load. The appropriate level of generation capacity value is inherently embedded in the IRP preferred portfolio resource costs because those resources achieve the stated goals of reliable operation and compliance with regional resource adequacy requirements.

# Part 2: Energy Storage Operating Parameters

This section discusses some of the key operating parameters associated with energy storage resources. Beyond just defining the basic concepts, it is important to recognize the specific ways in which these parameters are measured and ensure that any comparison of different technologies or proposals reports equivalent values. For example, many battery systems operate using direct current (DC) rather than the alternating current (AC) of most of the electrical grid. When charging or discharging from the grid, inverters must convert DC power to AC power, which creates losses that reduce the effective output when measured at the grid, rather than at the battery. To manage this distinction, PacifiCorp uses the AC measurement at the connection to the electrical grid for all parameters, as this aligns with the effective "generation input" of an energy storage resource. As previously discussed, an additional adjustment for line losses on the electrical grid may also be necessary, but that is dependent on the location and conditions on the electrical grid, rather than the energy storage resource.

- **Discharge capacity**: The maximum output of the energy storage system to the grid, on an AC-basis, measured in megawatts (MW). This is generally equivalent to nameplate capacity.
- **Storage capacity:** The maximum output of the energy storage system to the grid, on an AC-basis, when starting from fully charged, measured in megawatt-hours (MWh).
- **Hours of storage:** The length of time that an energy storage system can operate at its maximum discharge capacity, when starting from fully charged, measured in hours. Generally, the hours of storage will be equal to storage capacity divided by discharge capacity.
- **Charge capacity:** The maximum input from the grid to the energy storage system, on an AC-basis, measured in megawatts (MW).
- **Round-trip efficiency:** The output of the energy storage system to the grid, divided by the input from the grid necessary to achieve that level of output, stated as a percentage. A storage resource with eighty percent efficiency will output eight MWh when charged with ten MWh. If charge and discharge capacity are the same, losses result in a longer charging time. For instance, an energy storage system with four hours of storage, eighty percent efficiency, and identical charge and discharge capacity would require five hours to fully charge (4 hours of discharge divided by 80 percent discharge MWh per charge MWh).
- **State of charge:** This is a measure of how full a storage system is, calculated based on the maximum MWh of output at the current charge level, divided by the storage capacity when fully charged, and is stated as a percentage. One hundred percent state of charge indicates the storage system is full and can't store any additional energy, while zero percent state of charge indicates the storage system is empty and can't discharge any energy. As previously indicated, PacifiCorp's state of charge metric is based on output to the grid. As a result, the entire round-trip efficiency loss is applied during charging before reporting the state of charge. For example, a storage system with a ten MWh storage capacity and eighty percent efficiency would only have an eighty percent state of charge after ten MWh of charging had been completed, starting from empty.
- **Station service:** Round-trip efficiency is a measure of the losses from charging and discharging. Some energy storage systems also draw power for temperature control and other needs. This is typically drawn from the grid, rather than the energy storage resource.

Some energy storage technologies experience degradation of their operating parameters over time and based on use. The following parameters are used to quantify the effects of degradation.

- **Storage capacity degradation:** The primary impact of degradation is on storage capacity. Much of the degradation occurs as part of charge-discharge cycles and can be measured as the degradation per thousand cycles. After one thousand cycles, a four-hour storage system might only be capable of storing 3.5 hours of output. Some storage resources also experience degradation that isn't tied to cycles, for instance based on differing state of charge levels or time.

- **Cycle life:** This is the total number of full charge and discharge cycles that energy storage equipment is rated for. Three thousand cycles are common for lithium-ion resources, but operating under harsh conditions can also cause the effective cycle count to decline faster. Once storage capacity has degraded by thirty percent degradation per cycle may accelerate.
- **Depth of discharge:** Operating at a very high or very low state of charge, particularly for an extended period, can cause more rapid degradation. This metric can be used to identify how particular operations impact the effective remaining cycle life.
- **Variable degradation cost:** Lithium-ion energy storage equipment is composed of many battery modules, each of which experience degradation. These modules can be gradually replaced over time to maintain a more consistent storage capacity, or they can be replaced all at once when cycle limits are reached, at the expense of a reduced storage capacity in the interim. In either case, the replacement cost of storage equipment can be expressed per MWh of discharge and accounted for as part of resource dispatch.

## Part 3: Distributed Resource Configuration and Applications

This section described the potential benefits of different distributed resource siting and configuration options. Due to economies of scale, distributed resource solutions generally higher cost relative to utility-scale assets. Many of PacifiCorp's distribution substations have capacity more than fifteen megawatts, such that a battery of that size could be feasible at the distribution level, with the potential for incremental benefits relative to the transmission-connected battery resources modeled as part of the preferred portfolio. The most cost-effective locations for distributed resource deployment are likely to reflect a balance of local requirements and economies of scale.

### Secondary Voltage

A distributed resource which is located downstream from the high voltage transmission grid will have a larger energy impact than its metered output would indicate, due to line losses. This is true for both charging and discharging. To the extent discharging is aligned with periods with higher load, and charging is aligned with periods with lower load, the benefits will be proportionately higher. For example, the marginal primary voltage losses for Oregon have been estimated at 9.5 percent on average across the year. Savings based on primary losses would be appropriate to apply to a resource connected at the secondary voltage level so long as it is not generating exports to the higher voltage system, as losses would still occur within that level, but would be reduced due to lower deliveries across the higher voltage system. For lithium-ion batteries, there is also an incremental benefit related to variable degradation costs. While the effect of losses makes the battery appear larger from a system benefits perspective, it discharges the same amount, so the variable cost component doesn't scale with losses, creating an additional benefit that is captured in this energy margin.

In addition to incremental energy value, resources connected at primary or secondary voltage will also have a proportionately higher generation capacity value and will have a higher capacity contribution based on their ability to avoid primary losses. Such adjustments to account for avoided losses are also applied to energy efficiency and demand response measures.

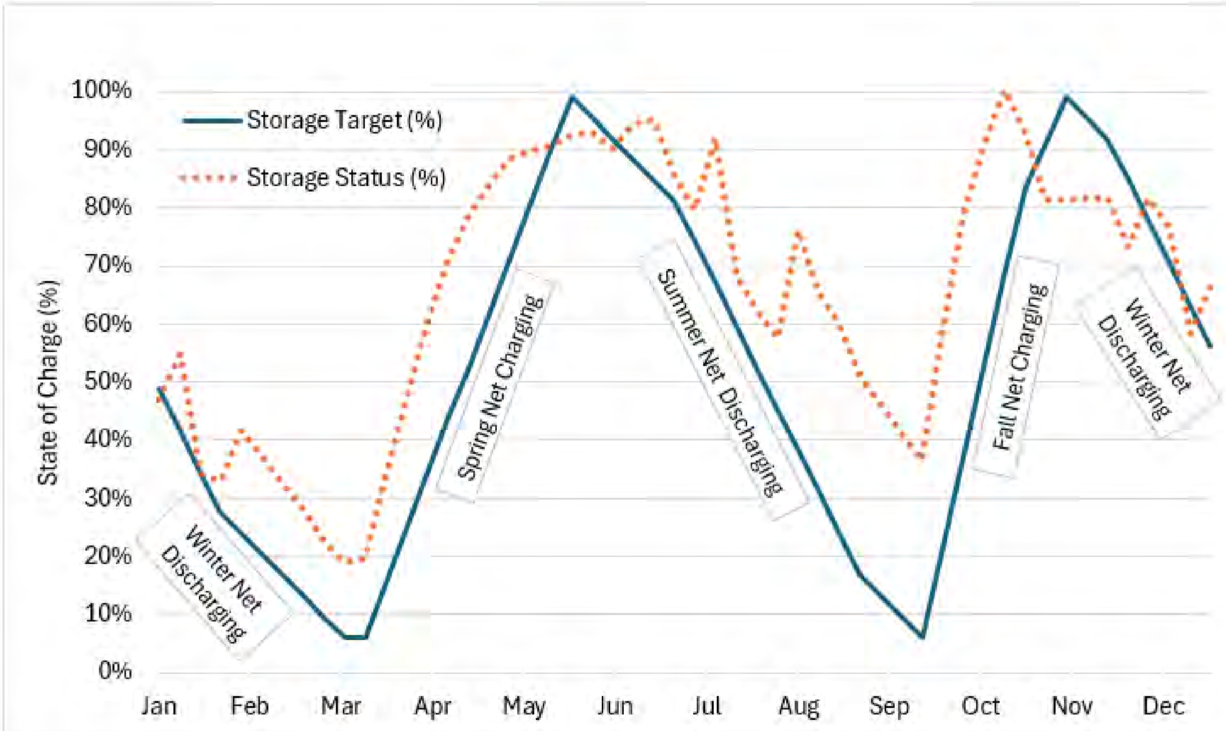
## T&D Capacity Deferral

As indicated in the grid services section, distributed resources can allow for the deferral of upgrades by reducing the peak loading of the transmission and distribution system elements serving their area. For deferral to be achieved, a distributed resource must reliably reduce load under peak conditions. However, the timing of peak conditions for a given area is likely to vary from the peak conditions for the system. As a result, the energy or generation capacity value of energy-limited resources used for a T&D capacity deferral application are likely to be reduced. For instance, when energy-limited resources are reserved for local area requirements they would not be available for system reliability events or a period of high energy prices.

## Long Duration Energy Storage

PacifiCorp's 2025 IRP preferred portfolio includes the addition of one-hundred-hour iron air storage in several locations around the system. The supply-side resource table also includes hydrogen resources with storage options of 24 hours or more. Optimization of energy storage resources with this much storage duration is somewhat more complicated than a four-hour or eight-hour battery, which PLEXOS is reasonably capable of optimizing within the one-week (168 hour) horizon of the ST model. To assist PLEXOS in managing the functionality of long duration storage, PacifiCorp sets state of charge targets to ensure storage with duration of 24 hours or more is gradually filled up during periods with relatively high supply and low demand, and allowed to deplete stored volumes across peak seasons when demand is high. Figure N.2 illustrates the two seasonal charging and discharging cycles modeled in each year, along with an example of PLEXOS-optimized results. The energy targets are not hard limits, and PLEXOS can also use extra charging to support additional discharging within the same week. However, the relatively low round-trip efficiency of one-hundred-hour iron air storage, at 44%, results in fewer opportunities for economic arbitrage than lithium-ion storage, which has an 85% round-trip efficiency.

**Figure N.2 – Long Duration Storage Charging and Discharging, Targets and Optimization**




While the seasonal cycles shown help to increase the benefits of one-hundred-hour iron air storage, there is the potential for further optimization. Rather than targeting uniform charging or discharging across a season, charging can be increased during periods when renewable supply is high and discharging can be increased shifted to allow more output on the highest load days. In the real world, future weather conditions are highly uncertain beyond the next week, so it is not possible to know that high loads in the first week of July won't be followed by even higher loads in the last week of July. Therefore, it is important to maintain a minimum state of charge during periods of possible peak-producing weather to ensure reliability. As discussed in Volume II Appendix K (Capacity Contribution), the longest loss of load event seen in analysis of the 2025 IRP preferred portfolio was ten hours, so reliability requirements are likely to outweigh economic arbitrage as the state of charge drops to that level. As an example, with a state of charge down to five hours of discharge, iron air storage might not be dispatched, despite market prices exceeding $100/MWh, ensuring output is available if demand increases or market prices go up in future periods. With a round-trip efficiency of 44%, iron air storage would need to be charged at costs of $44/MWh or less in order to economically discharge at $100/MWh. As the state of charge approaches zero, it would be economic to charge at up to $440/MWh to avoid the possibility of market pricing at $1,000/MWh. Administrative pricing provisions kick in at that point, limiting market outcomes, but adequate state of charge would still be needed for provision of operating reserves as well as to meet market requirements including balancing and flexibility tests. With all that taken into consideration, reliable system operation may result in charging at high prices and willingness to purchase at even higher market prices rather than discharge. This is true for any storage resource but is exacerbated for storage with a low round-trip efficiency. These reliability considerations could also be a factor for storage with a slow charging speed, such as hydrogen electrolysis sized below the hourly consumption of the associated hydrogen-fueled generator. As storage makes up a greater portion of a utility's resource mix, and that of a region as a whole, coordination to plan around and operate within these limitations will be increasingly important.

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# APPENDIX O – WASHINGTON CLEAN ENERGY ACTION PLAN

## Introduction

PacifiCorp's 2025 Integrated Resource Plan presents a fully compliant approach to meeting Washington obligations through long-term resource planning, near-term actions and ongoing evaluation and execution. In this appendix, the company presents the Clean Energy Action Plan and other components that bridge the evolution from the 2025 IRP to the filing of the 2025 Clean Energy Implementation Plan on October 1, 2025.

### Key Findings

1. Washington will require 3,448 megawatts (MW) of new situs-allocated renewable, non-emitting, and storage resources to meet its capacity, energy, and clean energy needs over the 21-year planning horizon, in addition to cost-effective demand-side management resources.
2. In the near-term, Washington customers will require 254 MW of new situs-allocated renewable resources before the end of 2029, and nearly 1 GW of battery storage.
3. Washington's clean energy interim targets will reach over 100% by 2030 and progress towards 2045 zero-greenhouse gas emissions goals steadily over the next 21 years.
4. The CETA-compliant preferred portfolio includes 700 MW of additional wind relative to the Alternative Lowest Reasonable Cost Portfolio.
5. PacifiCorp continues to grow in its approach to ensuring equitable benefits and outcomes across its customers throughout the clean energy transition.

### Background

The Clean Energy Transformation Act (CETA) was passed by the Washington State Legislature and signed into law by Governor Jay Inslee in May 2019. The legislation combines directives for utilities to pursue a clean energy future with assurances that benefits from a transformation to clean power are equitably distributed among all Washingtonians.[1]

The Washington Utilities and Transportation Commission began rulemakings to implement CETA in June 2019, and the first phase concluded in December 2020. As directed by the legislation and the CETA rules, Washington electric utilities must file the following long-term planning documents every four years:

**Clean Energy Action Plan:** The Clean Energy Action Plan (CEAP) is a ten-year planning document that is derived from the IRP and included as an appendix to the IRP. The CEAP provides a Washington-specific view of how PacifiCorp is planning for a clean and equitable energy future that complies with CETA.

**Integrated Resource Plan:** The IRP is a comprehensive decision support tool and roadmap for meeting the company's objective of providing reliable and least-cost electric

[1] 2019 WA Laws Ch. 288.

service to its customers. The plan is developed through open, transparent, and extensive public involvement from state utility commission staff, state agencies, customer and industry advocacy groups, project developers, and other stakeholders.[2]

The key elements of the IRP include: an assessment of resource need, focusing on the first 10 years of a 20-year planning period; the preferred portfolio of supply-side and demand-side resources to meet this need; and an action plan that identifies the steps that will be taken over the next two-to-four years to implement the plan.

**Clean Energy Implementation Plan:** The Clean Energy Implementation Plan (CEIP) is a plan that lists the specific actions PacifiCorp will take over the next four years to move toward the 2030 and 2045 clean energy directives, while also describing long-term clean energy interim targets through 2045. The CEIP also includes customer benefit indicators, developed with input from advisory groups. PacifiCorp's inaugural CEIP, covering the 2022-2025 planning period, was filed December 30, 2021. The company expects to file the next CEIP October 1, 2025, focusing on years 2026-2029.[3]

This Appendix O is included with the 2025 IRP in fulfillment of the requirement to file a CEAP for Washington. Described in WAC 480-100-620(12), the utility must develop a ten-year clean energy action plan implementing the CETA clean energy standards and must:

(a) Be at the lowest reasonable cost;

(b) Identify and be informed by the utility's ten-year cost-effective conservation potential assessment as determined under RCW **19.285.040**;

(c) Identify how the utility will meet the requirements in WAC **480-100-610** (4)(c) including, but not limited to:

(i) Describing the specific actions the utility will take to equitably distribute benefits and reduce burdens for highly impacted communities and vulnerable populations;

(ii) Estimating the degree to which such benefits will be equitably distributed and burdens reduced over the CEAP's ten-year horizon; and,

(iii) Describing how the specific actions are consistent with the long-term strategy described in WAC 480-100-620 (11)(g).

(d) Establish a resource adequacy requirement;

(e) Identify the potential cost-effective demand response and load management programs that may be acquired;

(f) Identify renewable resources, nonemitting electric generation, and distributed energy resources that may be acquired and evaluate how each identified resource may reasonably be expected to contribute to meeting the utility's resource adequacy requirement;

(g) Identify any need to develop new, or to expand or upgrade existing, bulk transmission and distribution facilities;

(h) Identify the nature and possible extent to which the utility may need to rely on an alternative compliance option identified under RCW **19.405.040** (1)(b), if appropriate; and

(i) Incorporate the social cost of greenhouse gas emissions as a cost adder as specified in RCW **19.280.030**(3).

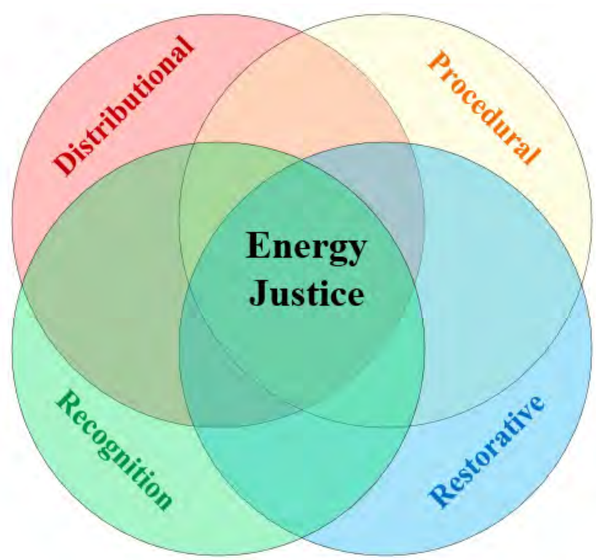
[2] WAC 480-100-620.

[3] WAC 480-100-640.

## Energy Justice

Washington's CETA guidelines and regulatory direction mandate the consideration of equitable distribution of energy and nonenergy benefits and burdens across populations.[4] The Washington Utilities and Transportation Commission leverages four core tenets of energy justice: distributional, procedural, recognition and restorative.[5] On September 29, 2023, the commission initiated Docket A-230217 (Equity Docket) to address the application of equity and justice in commission and regulated companies' processes and decisions.[6] On December 2, 2024, the commission communicated that it had determined it needed to adjust the schedule of the work in this proceeding until the first quarter of 2025 to re-evaluate and clarify the scope of work required. Activities within this docket at present are paused until further notice. PacifiCorp continues to monitor communications and activities within this docket to better understand how the four tenets overlap and reinforce each other to achieve energy justice.

**Figure O.1 – Tenets of Energy Justice**




The following discussion of energy justice describes how these tenets are relevant to PacifiCorp's path forward, clarifying the scope and meaning of energy justice as applied to the achievement of CETA standards. As acknowledged in regulatory agreements, CETA standards include not only readily quantifiable requirements, but also requirements that are qualitative in nature.[7] The four tenets generally fall into this second, qualitative, arena, and are devised to ensure that,

> "…all customers are benefiting from the transition to clean energy: Through the equitable distribution of energy and nonenergy benefits and the reduction of burdens to vulnerable

[4] RCW 19.405.060(1)(c)(iii); WAC 480-100-610(4)(5).

[5] *See, Commission-led Policy Statement to Address the Application of Equity and Justice in Commission and Regulated Companies' Process and Decisions,* Docket No. A-230217, Notice of Continuance (Dec. 2, 2024) (pending equity policy statement docket); Docket, *Washington Utilities and Transportation Commission v. Cascade Natural Gas Corporation*, Docket No. UG-210755, Final Order 09 at 18.

[6] Docket A-230217 Washington UTC Equity Docket

[7] Docket UE-210829, Order 06, Appendix A: Full Multi-Party Settlement Agreement, p. 12. "In future CEIPs, PacifiCorp will continue to include descriptions of quantitative (i.e., cost based) and qualitative (e.g., equity considerations) analyses that support interim targets to comply with CETA's 2030 and 2045 clean energy standards."

> populations and highly impacted communities; long-term and short-term public health and environmental benefits and reduction of costs and risks; and energy security and resiliency"[8]

In essence, CETA standards one (1) through three (3), below, are to be achieved within the protections of the standards four (4) and five (5):[9]

> (1) On or before December 31, 2025, each utility must eliminate coal-fired resources from its allocation of electricity to Washington retail electric customers;
> (2) By January 1, 2030, each utility must ensure all retail sales of electricity to Washington electric customers are greenhouse gas neutral;
> (3) By January 1, 2045, each utility must ensure that nonemitting electric generation and electricity from renewable resources supply 100 percent of all retail sales of electricity to Washington electric customers;
> (4) In making progress toward and meeting subsections (2) and (3) of this section, each utility must:
> > (a) Pursue all cost-effective, reliable, and feasible conservation and efficiency resources and demand response;
> > (b) Maintain and protect the safety, reliable operation, and balancing of the electric system; and
> > (c) Ensure that all customers are benefiting from the transition to clean energy through:
> > > (i) The equitable distribution of energy and nonenergy benefits and reduction of burdens to vulnerable populations and highly impacted communities;
> > > (ii) Long-term and short-term public health and environmental benefits and reduction of costs and risks; and
> > > (iii) Energy security and resiliency.
>
> (5) Each utility must demonstrate that it has made progress toward and has met the standards in this section at the lowest reasonable cost.

In the discussion which follows, PacifiCorp examines the fulfillment of the four tenets of energy justice as a component of achieving CETA's targets of transitioning the state of Washington to a clean energy future.

## Distributional Justice

> "…which refers to the distribution of benefits and burdens across populations. This objective aims to ensure that marginalized and vulnerable populations do not receive an inordinate share of the burdens or are denied access to benefits."[10]

PacifiCorp's modeling of resource selections in the IRP is agnostic to location, timing, technology, and sizing. This allows for the preferred portfolio to send a market signal in a future request for proposals for projects that fit an optimal view of future portfolio composition. While the IRP does not account for precise project details, which are as unknown at the time of publishing an IRP,

[8] RCW 19.405.060(1)(c)(iii).
[9] WAC 480-100-610.
[10] DOCKET UG-210755, Washington Utilities and Transportation Commission v. Cascade Natural Gas Corporation, Final Order 09, p. 18.

there are important considerations that can inform the analysis of candidate portfolios for the preferred portfolio, and also inform the downstream processes used to make bid acquisition decisions.

From the inception of CETA, and beginning with PacifiCorp's 2021 IRP and 2021 CEIP,[11] distributional justice has been incorporated into PacifiCorp's IRP modeling assumptions and customer benefit indicator (CBI) framework. In the 2025 IRP, the inclusion of competitive small-scale supply-side resources provides for energy and capacity resources that are tied to local community needs, mitigating possible downsides of transmission projects while potentially increasing community resiliency.

Distributional justice is also incorporated into the use and assessment of the social cost of greenhouse gases. This view of system planning increases economic cost but also increases nonenergy benefits for Washingtonians by capturing the non-monetary burdens imposed by greenhouse gas emissions.

PacifiCorp's Maximum Customer Benefit case is designed to address distributional justice by avoiding those portfolio elements that can disproportionately burden vulnerable communities. [12] This case is operationalized by 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 those customers. In this study, Washington's load forecast reflects the high private generation forecast. Also, the study assumes the social cost of greenhouse gas price-policy scenario and includes all available Washington energy efficiency and demand response. The Maximum Customer Benefit case is introduced in Chapter 8. Additional detail and portfolio results are provided later in this appendix.

Distributional justice is also represented in the consideration of CBIs. While it is important to note that the concept of distributional justice is represented in all of PacifiCorp's CBIs, only four of ten elements of the CBI framework explicitly represent non-energy benefits to highly impacted and vulnerable communities, as well as other potentially underrepresented people. These specific CBIs are to:

- Increase culturally and linguistically responsive outreach by engaging in efforts to improve language accessibility and developing communications strategies that target highly impacted and vulnerable communities.
- Increase community-focused efforts and investments by enhancing incentive programs to improve accessibility for highly impacted and vulnerable communities.
- Increase participation in energy efficiency and billing assistance programs like low-income weatherization and the Washington Low-Income Bill Assistance (LIBA) programs.
- Improve indoor air quality through promotion of weatherization programs that target highly impacted and vulnerable communities.

[11] 2021 IRP filed on September 1, 2021, https://www.pacificorp.com/energy/integrated-resource-plan.html; 2021 CEIP filed on December 31, 2021, https://www.pacificorp.com/energy/washington-clean-energy-transformation-act-equity.html

[12] 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."

Beyond the reduction of energy costs, nonenergy benefits help vulnerable communities by improving their overall quality of life, including aspects such as improved health, comfort, safety, and housing quality, which are particularly important for populations facing economic hardship or environmental challenges that might exacerbate their vulnerabilities.[13]

To prioritize diverse suppliers, PacifiCorp is expanding its non-price scoring methodology that will be applied to resource bid evaluation in forthcoming RFPs. These were first identified in the 2021 IRP/CEAP for use in subsequent RFP processes. The company will consider non-price metrics again in procurement activities following the 2025 IRP. As part of this effort, PacifiCorp is looking at further refinement of its non-price scoring to include explicit consideration of 1) the four energy justice tenets and 2) its CBIs (where appropriate). These may include, for example, consideration of local job creation, continuing education and apprenticeship opportunities, and Use of Disadvantaged Business Enterprises and/or tribal, women, or minority owned subcontractors in its evaluation of bidder proposals.

## Procedural Justice

> "…which focuses on inclusive decision-making processes and seeks to ensure that proceedings are fair, equitable, and inclusive for participants, recognizing that marginalized and vulnerable populations have been excluded from decision-making processes historically."[14]

Unlike distributional justice, which looks primarily at the fairness of the final result, procedural justice emphasizes the fairness of the steps taken to reach that result. The focus is therefore on the equitability of the decision-making process itself, regardless of the final outcome, to ensure voices are heard and opportunities are fairly distributed, even if participants do not ultimately obtain the full result they wanted.

The 2025 IRP and related downstream processes seek to give people a voice, treat them with respect, and demonstrate trustworthiness. The primary avenue for procedural energy justice in the CEAP can be found in our expanded public participation opportunities, described later in this appendix.

Some of the same CBI framework considerations that help to ensure the fair distribution of outcomes are also tied to procedural justice through efforts to broaden participation. This includes, for example, development of communication strategies that target highly impacted and vulnerable communities. It may also include engaging interested parties by increasing the number of informational events regarding energy-related programs, like public meetings.

In addition to the steps taken regarding CETA participation specifically, the 2025 IRP also significantly advances its participation and incorporation of public input. More than in any previous IRP, PacifiCorp has greatly expanded efforts to provide responsiveness and open discussion in its public input meeting series. Key topics were introduced earlier and often, and in advance of key decision-making. The link between public input and the handling of critical topics

[13] Refer to *Portfolio Impacts* and *Customer Benefit Indicators* later in this appendix.

[14] DOCKET UG-210755, Washington Utilities and Transportation Commission v. Cascade Natural Gas Corporation, Final Order 09, p. 18.

has been made more transparent by directly linking requests and comments to responses in the 2025 IRP document.[15]

Also in the 2025 IRP, participants increasingly drove the amount of time spent on various topics, including open discussion of the entirety of the Draft 2025 IRP in the public meetings held on January 22-23, 2025, and February 26-27, 2025. At each of these meetings, significant and open-ended time was devoted to discussion lead by stakeholders, with no preset agenda. This resulted in robust explorations of the ideas and concerns of stakeholders. PacifiCorp has and will continue to also hold CEIP-specific engagement sessions to allow interested parties opportunities to engage with specific elements of the final CEIP to be filed later this year. Part of increasing accessibility to this material includes releasing a draft CEIP 45 days prior to filing, to allow for robust and thoughtful feedback.

In this cycle, PacifiCorp publicly posted key documents in development, such as the draft Conservation Potential Assessment and the supply-side resource table. Stakeholder feedback forms have also been posted publicly and incorporated in the IRP and are summarized in the 2025 IRP Appendix M. Additionally, PacifiCorp has again refined and expanded its treatment of public workpapers for greater access.

## Recognition Justice

> "…which requires an understanding of historic and ongoing inequalities and prescribes efforts that seek to reconcile these inequalities."[16]

Recognition justice entails "acknowledging historical injustices and ensuring that the transition [to clean energy] does not further marginalize already vulnerable groups."[17]

In incorporating recognition justice, the company through collaboration with advisory groups and external parties seeks to understand and acknowledge differences, respect identity, ensure participation and recognize systemic injustices, which can then be addressed via procedural, restorative and distributional justice.

In addition to the effort of the Washington advisory groups, the IRP and the CEAP further the success of recognition justice through the identification of Named Communities, multiple public input processes, and through assessments such as the Non-Energy Impact Mapping in its Conservation Potential Assessment.[18]

[15] Refer to Appendix C (Public Input Process) and Appendix M (Stakeholder Feedback Forms).
[16] DOCKET UG-210755, Washington Utilities and Transportation Commission v. Cascade Natural Gas Corporation, Final Order 09, p. 18.
[17] U.S. Department of Energy, DOE P 120.1, ENERGY AND ENVIRONMENTAL JUSTICE POLICY, p.4, 11/26/2024.
[18] Refer to the "2025 CPA - Appendix E - WA Non-Energy Impact Mapping" as part of the CPA supplemental materials posted on the website, which maps the accrual of NEIs to various groups of measures available to customers consistent with WAC 480-100-620(13): https://www.pacificorp.com/energy/integrated-resource-plan/support.html

## Restorative Justice

> *"Which is using regulatory government organizations or other interventions to disrupt and address distributional, recognitional, or procedural injustices, and to correct them through laws, rules, policies, orders, and practices."*[19]

Unlike the prevention-focused tenets of procedural, distributional and recognition justice, a central feature of restorative justice is rectifying the injustices of the past. Restorative justice seeks to address the negative impacts of energy production and consumption through proactive measures that prioritize community involvement and restoration of balance.

For example, on a simple cost-basis it can be less expensive to locate disruptive transmission projects to pass through vulnerable communities, creating a disproportionate burden laid upon these communities. In the 2025 IRP, small scale renewable resources are open for selection during capacity expansion optimization, allowing the model to weigh the balance of potentially higher resource costs against the avoidance of large transmission projects, with an opportunity to also account for the nonenergy benefits of local community resilience. The aforementioned addition of non-price scoring metrics adds another link to restorative justice in downstream acquisition efforts.

PacifiCorp also provides funding to support assistance offerings to customers experiencing financial hardships within the company's Washington service area. For example, the Low-Income Bill Assistance (LIBA) program provides a discount to income eligible households year-round. For another example, local agencies in Washington leverage PacifiCorp funding streams to provide free weatherization services to income-qualifying homeowners and renters living in single-family homes, mobile homes, or apartments. These offerings are presented to customers on the company website alongside links to Project HELP and the Low-income Home Energy Assistance Program (LIHEAP).[20]

In addition to remediation, key elements of restorative justice include:

- **Community engagement:**
  Common to all tenets of energy justice, community engagement is a core principle is actively involving vulnerable communities in discussions and decision-making regarding new energy projects, ensuring their voices are heard and concerns addressed.
- **Transparency:**
  Energy justice cannot succeed without appropriate transparency, which supports IRP public feedback and shapes the context of decision-making.
- **Enhancing Grid Resilience and Reliability:**
  The concept of restorative justice involves accounting for current and historic injustices related to existing energy systems and acting to remediate them. This includes, for example, prioritization of grid hardening projects in areas subject to more frequent and longer duration outages, or of greater climatological risk.

[19] DOCKET UG-210755, Washington Utilities and Transportation Commission v. Cascade Natural Gas Corporation, Final Order 09, p. 18.

[20] See PacifiCorp's Bill payment assistance webpage for Washington: https://www.pacificpower.net/my-account/payments/bill-payment-assistance.html

The following sections describe how a long-run portfolio is optimized to meet CETA's clean energy standards at least-cost, least-risk, while incorporating consideration for the equitable distribution of benefits and reductions of burdens to highly impacted and vulnerable communities.

# Portfolio Development

The 2025 IRP process serves as the basis for developing and identifying the 10-year action plan that will put the company on a path towards compliance with the CETA clean energy standards. Refer to Chapter 3 for an overview of environmental policy regulation, including Washington state policies. Chapter 6 presents the base load forecast and existing resources represented in modeling. Chapter 7 presents a complete list of proxy resource options available for endogenous selection. Chapter 8 explains each step involved in the development and evaluation of resource portfolios. Chapter 9 includes the preferred portfolio and list of specific resources selected to meet Washington's compliance requirements and reliability needs.

PacifiCorp's CEAP is planning toward a future in Washington that balances a rapid transition to renewable and non-emitting energy as directed under CETA, with the company's continued commitment to ensure that customers are served affordably, safely, and reliably. To meet reliability standards in a future that includes an increasing number and type of variable resources, the company carefully analyzes the way its programs, generation resources, customer load obligations, cost-effective conservation potential fit together to ensure reliability.

## Resource Portfolio Development

As discussed in Chapter 8, PacifiCorp uses the PLEXOS long-term (LT) model to produce resource portfolios with sufficient capacity to meet all load and operating reserves requirements over the study horizon appropriate to achievable granularity. Each of these portfolios is uniquely characterized by variables on PacifiCorp's system, including type, timing, location, and size of resources needed to achieve reliable operation. Each portfolio is also evaluated in the short-term (ST) model to establish system costs over the planning horizon. 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). Stochastic modeling is also done using the ST model, and this process has been expanded to now include wind and solar generation profiles, and energy efficiency profiles for weather-sensitive bundles, in addition to the variables reflected in past IRPs. Appendix H (Stochastics) discusses the methodology for developing the stochastic inputs for the 2025 IRP.

These resource portfolios reflect a combination of planning assumptions such as resource retirements, $CO_2$ prices (also applicable to $CO_2$ equivalent emissions, or "$CO_2e$"), wholesale power and natural gas prices, load growth net of assumed distributed 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.

## Portfolio Integration and Resource Allocations

Since the filing of the 2021 IRP and inaugural CEIP, PacifiCorp has made strides in its modeling process, particularly in regard to the consideration of multiple and competing state obligations. The IRP process inherently represents a systemwide approach and produces a systemwide preferred portfolio. In its inaugural CEIP, PacifiCorp layered on CETA compliance requirements after an optimized portfolio was created for the system, inclusive of the social cost of greenhouse gas (SCGHG) price policy. Since the filing of the 2021 IRP, more state-specific policies have become considerations that the company must show are being met simultaneously.

The process of "portfolio integration" introduced in the 2025 IRP is a methodology under which each state's set of requirements, obligations and resource needs is optimized for and then integrated into a single portfolio of proxy resource selections. Every final integrated portfolio variant and sensitivity, unless otherwise stated, reflects the optimized set of proxy resource selections to meet each states' obligations. The 2025 IRP preferred portfolio of resources represents a set of resources optimized to achieve CETA compliance as well as all other state requirements that PacifiCorp is subject to. Refer to Chapter 8 for the details of the portfolio integration process. For Washington customers, the base portfolio includes the SCGHG price policy assumption in the model runs and in all resource decisions, and the final preferred portfolio reflects those selections. Finally, we also show the preferred portfolio dispatched under SCGHG to capture energy-specific outcomes for Washington customers, which are the basis for the clean energy interim targets depicted later in this appendix.

Assumptions are made regarding cost-allocation of resources. In lieu of a multi-jurisdictional cost allocation protocol that extends past the 2020 Protocol (set to expire December 31, 2025), all existing resources are assumed to be allocated (both in terms of costs and generation) in accordance with the 2020 Protocol and Washington Inter-Jurisdictional Allocation Methodology (WIJAM) indefinitely.[21] In most cases, this means existing renewable resources are allocated to Washington customers based on a forecast of their system-generation (SG) factor, which is determined based on their relative jurisdictional load. In some instances, like for qualifying facilities (QFs) existing resources are situs-allocated (100 percent) to Washington customers. Washington also receives a different share of existing emitting resources that it participates in (discussed in more detail in following sections). In regard to new proxy resource selections, it is assumed that any new proxy resources selected to serve Washington need are situs allocated, including both supply-side and demand-side resources.[22] These resource allocation assumptions underlie progress toward CETA clean energy targets, as explained in a later section.

## Resource Adequacy

As described in Chapter 8, the 2025 IRP ensures resource adequacy for the system and by state by requiring each portfolio to include sufficient resources to be compliant with the Western Resource Adequacy Program (WRAP), both in aggregate and for the loads and resources specific to the jurisdiction under evaluation. In addition, portfolios must be able to meet hourly load requirements without significant energy shortfalls, and the iterative portfolio development process increases

[21] The 2020 Protocol was adopted by the Public Utility Commission of Oregon order no. 20-024 on January 23, 2020 (available online at https://edocs.puc.state.or.us/efdocs/HAA/um1050haa161935.pdf.).

[22] The only "proxy" resource selected in the 2025 IRP that is considered a system resource and is allocated based on system generation factors is the Natrium nuclear demonstration project.

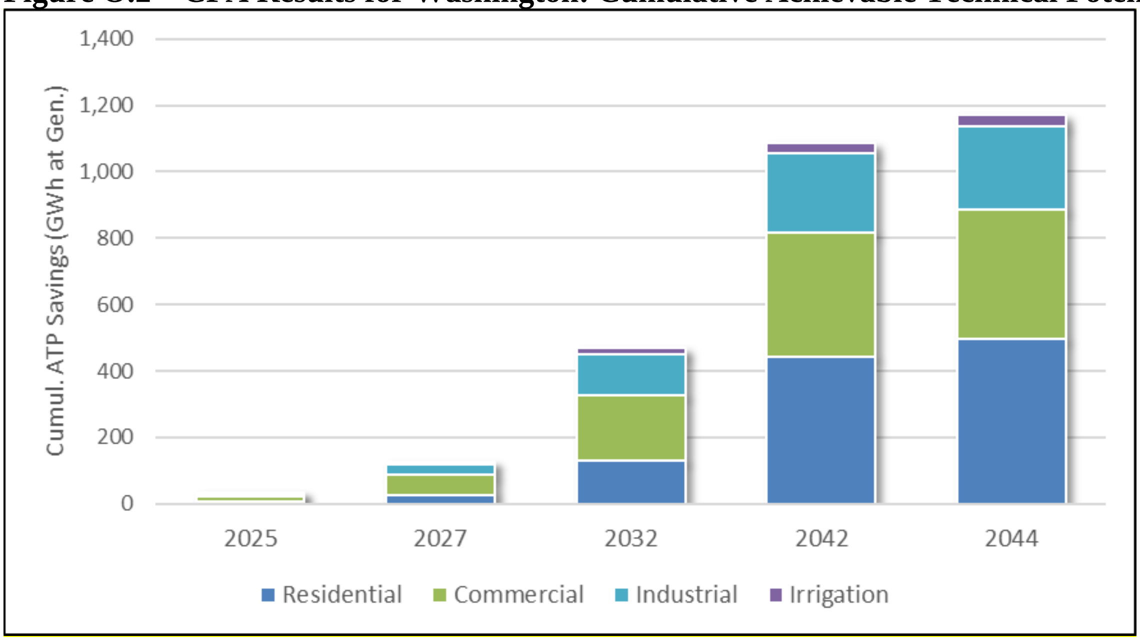
planning requirements within the LT model to account for shortfalls identified within the more granular ST model.

**Conservation Potential Assessment**

New cost-effective energy efficiency measures and programs are among the new resource options that are present in every portfolio described in the process above. These resources are first identified through the development of a conservation potential assessment (CPA) which identifies the magnitude and cost of all technically achievable energy savings opportunities in PacifiCorp's service area over the next 20 years.

Several measures include quantified non energy impacts (NEI) netted against measure cost. Examples include health benefits from avoided woodsmoke with installation of ductless heat pumps, operations and maintenance cost savings with new lighting, and water savings for measures which conserve water use as well as electricity use.[23] For the past several IRP cycles, PacifiCorp has contracted with Applied Energy Group (AEG) to conduct this assessment. A comprehensive description of the study methodology, underlying assumptions, and results can be found on PacifiCorp's website.[24] Figure O.2 shows cumulative achievable technical potential results from the CPA for the Washington service area.

**Figure O.2 – CPA Results for Washington: Cumulative Achievable Technical Potential**




The study results in nearly 30,000 individual efficiency measures which are then bundled into 27 groups for each of PacifiCorp's six states.

The output from the CPA serves as an input to the PLEXOS model which selects the optimal mix of resources from the defined bundles to provide system adequacy in a least-cost, least-risk manner. The conservation resources which are selected in the preferred portfolio become the cost-effective conservation potential.

[23]See Volume II, Appendix E - CPA for details on NEI-measure mapping used in the CPA.
[24] Available online at https://www.pacificorp.com/energy/integrated-resource-plan/support.html

### Demand Response and Load Management Programs

Cost-effective demand response (DR) and load management resources are identified and selected in a manner similar to conservation resources. The scope of the CPA also includes identification of the technical potential for direct load control (DLC) demand response opportunities and for potential new pricing programs. The methodology and all underlying assumptions and results for these resources can also be found on PacifiCorp's website.[25]

DLC resources are differentiated by customer, technology, and duration. Sustained duration resources are available for more than 20 minutes while short duration reflects load which can be curtailed in greater quantity but for shorter duration such as for frequency response over 5-minute increments where the customer is less likely to be impacted by the disruption.

The amount and cost of load curtailment or shift is characterized by customer type and type of end use that is being controlled. The technical achievable potential is an input to the IRP model as a resource option to be selected to meet system adequacy. DR selections by the model are cost effective potential to be acquired as a part of the preferred portfolio.

Pricing programs include time-of-use rates, critical-peak pricing, and other behavioral pricing tools. The third focus of the CPA is to quantify the technical potential and magnitude of demand impacts possible through these pricing designs. The results are used to inform future rate design concepts that are proposed with rate cases, but the IRP model is not used to determine the type and amount of pricing programs as a part of the preferred portfolio. This is because all pricing programs are designed to be cost effective to the system but may not be cost effective for the individual customer to select. Therefore, setting targets for programs that only benefit the utility system but not customers is not appropriate for the IRP but is analyzed and designed through other stakeholder and regulatory processes.

### Distributed Energy Resources

PacifiCorp provides customers in Washington access to an expanding number of distributed energy resources (DER) offerings and correspondingly includes these in the company's planning efforts. DERs include energy conservation, demand response, and load management (including customer-sited batteries and transportation electrification (TE)), and distributed generation. Planning for energy conservation and DR and load management is characterized in the CPA as described above. DER program offerings are described in Appendix D.

PacifiCorp is continuing to expand its DR offerings in Washington and is adding new programs and growing the amount of flex load capacity and use-cases represented across customer classes and technologies. New programs include CoolKeeper, Wattsmart Batteries, and electric vehicle DR. While total TE adoption is relatively low in PacifiCorp's service area compared to other parts of Washington, it is still growing and the company offers a number of customer programs, including grants, outreach and education, charging pilots for commercial and multifamily customers, as well as public charging and highway corridor plans. PacifiCorp is currently expanding its successful and innovative Wattsmart Battery program into Washington to promote

[25] Review PacifiCorp's 2025 CPA online at: https://www.pacificorp.com/energy/integrated-resource-plan/support.html

and incentivize the installation of individual batteries for system integration to facilitate grid management.

New customer-sited generation is forecasted within the Distributed Generation Long-Term Resource Assessment, which is included as Appendix L in the 2025 IRP. This assessment was conducted by DNV for all states and for each distributed generation resource type including solar photovoltaic (PV), small-scale wind, small-scale hydro, reciprocating engines, and micro-turbines. The resource costs and state-specific policies and incentives are integrated into the forecast of customer adoption of these resources across low, base, and high-case scenarios. The base case results are netted against each state's load forecast. Washington distributed generation assumptions are shown in Figure O.3 and Figure O.4.

**Figure O.3 – Cumulative new distributed generation capacity installed by scenario (MW-AC), Washington, 2018-2043**

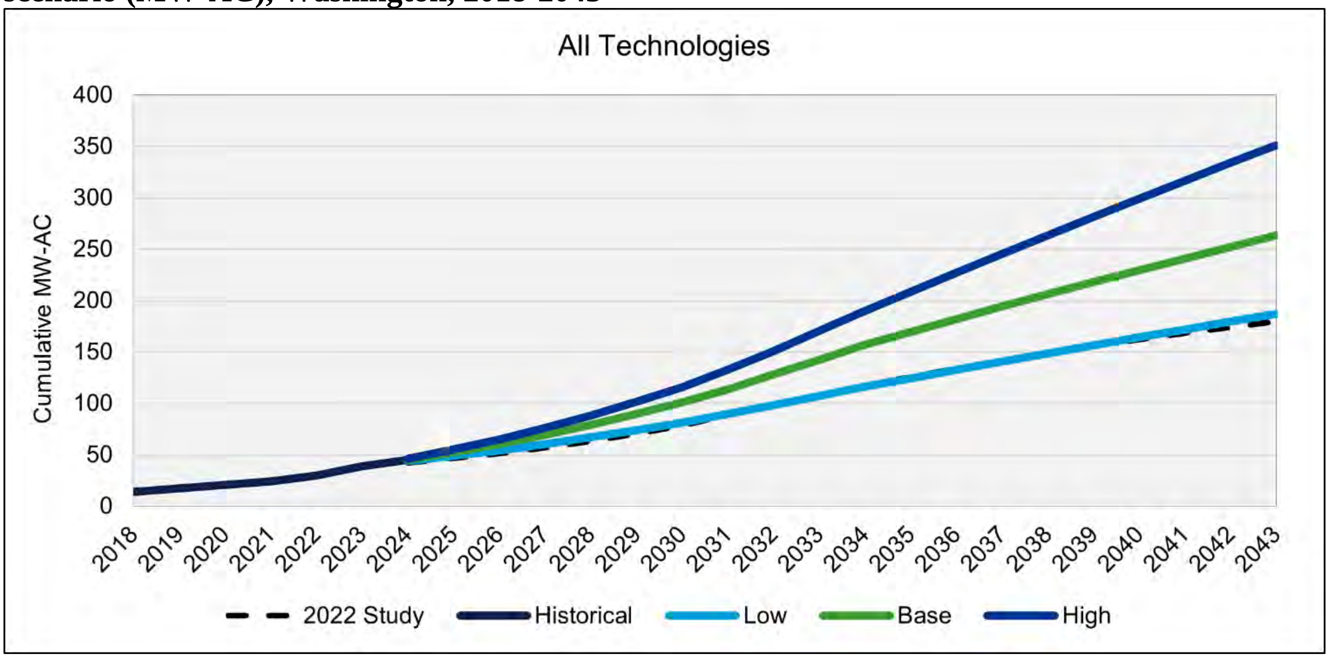
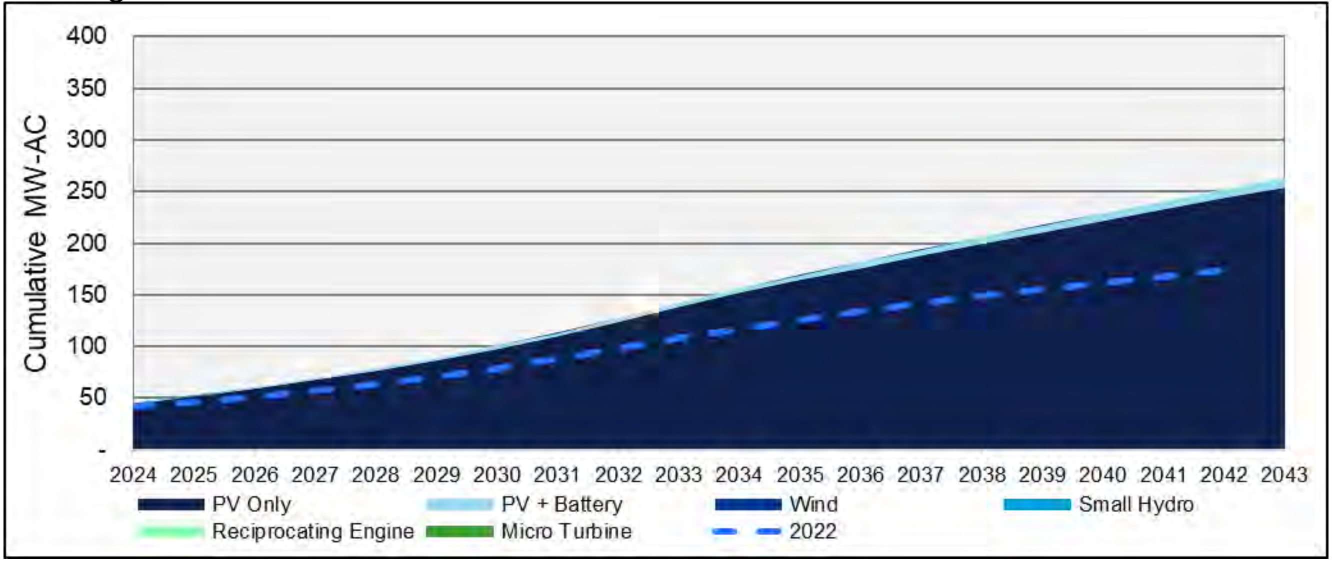


**Figure O.4 – Cumulative new capacity installations by technology (MW-AC), Washington base case, 2024-2043**




## Transmission

PacifiCorp uses a transmission topology that captures major load centers, generation resources, and market hubs interconnected via firm transmission paths. 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.

In support of the renewable resource additions identified for Washington in the 2025 preferred portfolio, PacifiCorp has identified transmission options that will reinforce existing transmission paths, allow for increased transfer capability, and will support the interconnection of new renewables. A summary of PacifiCorp's identified transmission additions serving Washington is shown in Table O.1.

**Table O.1 – Transmission Selections Supporting Washington Resources[1,2]**

| | | Export (MW) | Import (MW) | Interconnect (MW) | Build Investment ($m) | Build (%) | From | To |
|---|---|---|---|---|---|---|---|---|
| 2028 | Cluster 1 Area 11: Willamette Valley | 0 | 0 | 199 | 14 | 100% | n/a | n/a |
| 2028 | Cluster 1 Area 14: Summer Lake | 400 | 400 | 400 | 111 | 100% | Summer Lake | Hemingway |
| 2028 | Cluster 1/2/3: Walla Walla | 0 | 0 | 393 | 328 | 100% | n/a | n/a |
| 2028 | Serial/Cluster 1/2: Yakima | 0 | 0 | 628 | 64 | 100% | n/a | n/a |
| 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 |
| 2030 | Walla Walla - Yakima 230 kV | 400 | 400 | 400 | 142 | 100% | Walla Walla | Yakima |
| 2039 | Walla Walla - Central Oregon 500 kV | 1,500 | 1,500 | 670 | 1,463 | 100% | Walla Walla | Central OR |
| **Grand Total** | | **3,800** | **3,800** | **3,753** | **3,406** | | | |

[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 project-specific timing and some costs are project-specific.

### Development of a Washington-Compliant Portfolio

The 2025 IRP produces an integrated preferred portfolio that is developed to be compliant with state-specific requirements in all of PacifiCorp's jurisdictions, including Washington's CETA standards, while ensuring that the allocation of resources within the portfolio reflects the selections under the modeling requirements of each individual jurisdiction. All resources for Washington customers and compliance obligations are optimized and selected under the SCGHG price policy assumption. The model optimizes across a range of supply-side resource options, including renewable, non-emitting and storage resource options in addition to DSM resources, given various economic and regulatory inputs and assumptions.

An important update in this 2025 IRP and CEAP, is that the modeling process allows for endogenous selection of resources to serve individual state-specific requirements. Additionally, the preferred portfolio, integrates all system and state-specific resources into one resource portfolio. Several key assumptions are required to determine what existing resources are allocated to Washington customers and at what share, what new proxy resources can be allocated to Washington customers and if those resources are acquired as system or situs (allocated solely to Washington customers), and how those resources and the energy generated contribute towards CETA standards.

To estimate the mix of energy forecasted to serve Washington customers in any given model run, it was assumed that generation resources are allocated in accordance with the methodology defined under the WIJAM for existing resources and generally assumed that these assumptions hold into the future, in the absence of an agreed upon future allocation methodology.[26] All new proxy resources (renewable or non-emitting resources) that are determined within Washington's jurisdictional base portfolio, are assumed to be acquired solely to meet Washington's needs and are thus assumed to be situs-allocated. Resources acquired in other jurisdictional portfolios are situs-allocated to those states. If there is a system proxy resource (non-emitting) selected, that would be allocated to Washington customers on an SG basis. The allocations assumed for Washington are the Company's best estimate of future allocations at this time and are best aligned with other ongoing filings in Washington.

To calculate the energy and the total amount of renewable and carbon non-emitting energy allocated to Washington customers that make up the CETA clean energy interim targets, the company made the assumptions set forth below. Generally, where a resource is assumed to generate renewable energy credits (RECs), where one REC is generated for one megawatt-hour of renewable energy, the resource was assumed to generate CETA-compliant energy. In addition to REC-generating resources, it was assumed that all Washington-allocated energy from non-emitting resources was also CETA compliant, namely hydroelectric, nuclear and biodiesel peakers.[27] In summary, the resource allocation assumptions are:

[26] The WIJAM and the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol (2020 Protocol) define how resources and costs are allocated to Washington customers through December 21, 2023. The Washington Utilities and Transportation Commission approved the WIJAM and 2020 Protocol in its Final Order 09/07/12 in docket UE-191024 et. al., effective January 1, 2021. The company is in the process of negotiating its Multi-State Process (MSP) cost allocation methodology with the commissions and stakeholders in the six states it serves. More information can be found in Volume I, Chapter 3.

[27] WAC 480-100-610(3) states that by January 1, 2045, each utility must ensure that "non-emitting electric generation and electricity from renewable resources supply one hundred percent of all retail sales of electricity to Washington electric customers".

1. Allocation of energy for all existing renewable resources (non-QFs), are allocated according to system-generation (SG) factors, consistent with the WIJAM, if designated a "system" resource.
2. Allocation of energy for new "system" non-emitting proxy resources are allocated on SG factors, consistent with the WIJAM.
3. Allocation of energy for all Washington qualifying-facilities (QFs) are assumed to be situs to Washington. No energy is allocated from QFs not originating in Washington, consistent with Washington Utilities and Transportation Commission policy.
4. Washington customers are assumed to participate in a limited set of emitting resources as defined under the West Control Area Inter-Jurisdictional Allocation Methodology (WCA):
    a. Washington customers receive costs and benefits from PacifiCorp's interest in the Colstrip Unit 4 and Jim Bridger Units 1-4 thermal resources, subject to elimination of all costs and benefits from coal-fueled Colstrip 4 and Jim Bridger Units 3 and 4 until the end of 2025.
    b. Washington customers continue to receive benefits from Jim Bridger Units 1-2 after they convert to run on natural gas starting in 2024, until the end of 2029.
    c. Washington customers participate in two gas-fired units, Chehalis and Hermiston, through 2044.
5. New proxy renewable and non-emitting resources are allocated situs (100%) to Washington when determined to be incremental resources for Washington need.

Given the assumed allocations of resource energy and costs to Washington, CETA-compliant energy is determined given the following:

1. For existing REC-generating resources, generation of CETA-compliant energy is consistent with the company's REC entitlement start and end date. All existing hydroelectric is presumed to be CETA-compliant, even where the company does not currently get RECs for it.
2. Customer preference and voluntary renewable resources were not assumed to generate RECs for the system or the state of Washington and thus are not included in the allocation of renewable energy.
3. All new or proxy renewable and non-emitting resources were assumed to be CETA compliant, including wind, solar, geothermal, and nuclear. For renewable resources co-located with battery storage, RECs were assumed to be generated pre-storage; no RECs are generated at battery discharge.
4. Emitting fossil generation (coal or gas-fueled resources) or unspecified market purchases are not CETA-compliant.

Washington retail electric sales are defined as total energy served to customers annually, net of distributed generation, existing and optimized energy efficiency, and DSM resources. Retail electric load does not include MWh delivered from Washington qualifying facilities under the federal Public Utility Regulatory Policies Act of 1978 (PURPA).[28] CETA compliance targets were calculated annually as a percentage of Washington retail electric sales. Annual targets for CETA's 2030 and 2045 requirements were calculated as a percentage of Washington retail electric sales to

[28] RCW 19.405.020(36)(a)

be the total renewable and carbon non-emitting energy the company estimates will be provided to Washington customers.

Based on these assumptions, a CETA-compliant portfolio was developed and is the basis for the clean energy interim targets depicted in the following section.

## Portfolio Results

All portfolio results from the 2025 IRP are presented in Chapter 9. Table 9.3, specifically, shows the Washington-allocated megawatts (MW) of resources selected in the preferred portfolio. Table O.2 recasts the same information that is presented in Chapter 9, Table 9.3 but delineates which incremental proxy resource selections for Washington are considered "situs" or 100 percent allocated to Washington customers because they are selected only for Washington need (versus Washington's share of a systemwide proxy resource). As Table O.2 shows, all resource selections, except for the single "nuclear" resource category, represent situs-allocated resources for Washington customers. Table 9.3 also shows that up to 212 MW of the solar resources allocated to Washington in 2030 could be accelerated to an earlier date.

## Table O.2 - Incremental Resource Additions for Washington Customers, by Resource Allocation Assumption

| **Incremental resource additions for Washington, by resource type and year** | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Installed Capacity, MW** | | | | | | | | | | | | | | | | | | | | | |
| **Situs proxy resources** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** | **2034** | **2035** | **2036** | **2037** | **2038** | **2039** | **2040** | **2041** | **2042** | **2043** | **2044** | **2045** | **Total** |
| 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 Peaking | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 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 |
| | | | | | | | | | | | | | | | | | | | | | | - |
| **System-shared proxy resources** | | | | | | | | | | | | | | | | | | | | | | - |
| Nuclear | - | - | - | - | - | - | - | 32 | - | - | - | - | - | - | - | - | - | - | - | - | - | 32 |

In the near-term, the 2025 IRP preferred portfolio selects 254 megawatts (MW) of new renewable resources situs to Washington customers, expected to come online by the end of 2029, including 153 MW of wind and 101 MW of utility-scale solar. In this same time frame, almost 1 gigawatt (GW) of batteries (shorter-duration batteries, under 8 hours) are also selected to meet Washington's resource adequacy and capacity needs. The portfolio also includes selections of 44 MW of additional energy efficiency selections and 17 MW of demand response.

Between 2030 and 2035, another 1,095 MW of renewable resources are selected. This includes 407 MW of wind and 688 of solar. An additional 168 MW of shorter-duration batteries are selected plus 255 of longer duration batteries (24 hours and longer). Over these years, the model also selects an additional 111 MW of energy efficiency and just 2 MW of demand response resources.

Over the entire 21-year planning horizon, through 2045 when CETA's zero-greenhouse gas emitting standard begins, the preferred portfolio selects around 1.7 GW of new renewable resources, over half of which is utility-scale solar, and the rest is wind. The portfolio also includes significant battery selections totaling 1.6 GW. Total energy efficiency selections equate to 280 MW and demand-response is 51 MW.

The 10-year action plan to make progress towards CETA standards through the end of 2035 includes not only over 1 GW of new renewable resources, but significant storage capacity to help address Washington customer's capacity needs, totaling just over 1,400 MW. The company will continue to rely on conservation and demand-response as appropriate and efficient, which will be refined in downstream processes as explained in later sections.

## Washington Sensitivities

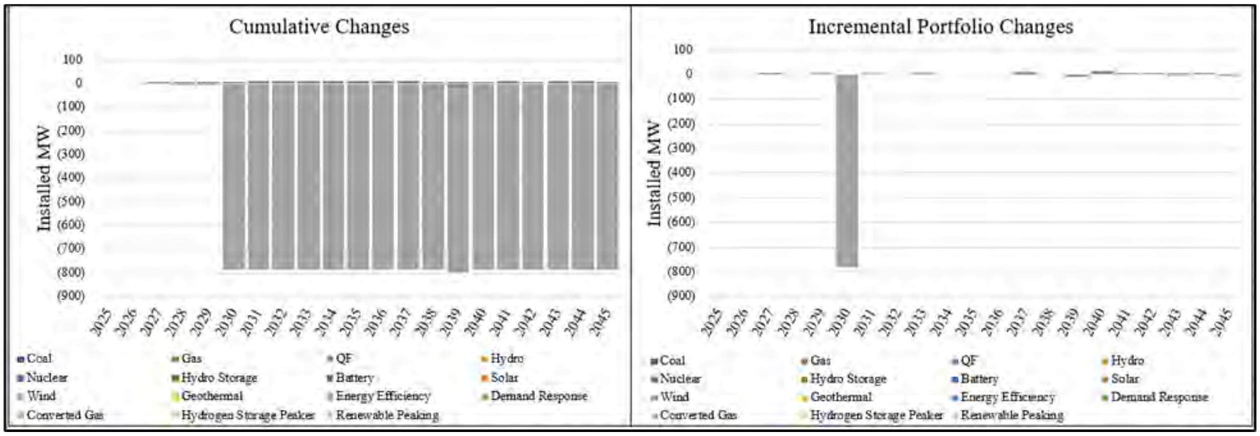
WAC 480-100-620(10)(b) instructs utilities to "incorporate the best science available to analyze impacts including, but not limited to, changes in snowpack, streamflow, rainfall, heating and cooling degree days, and load changes resulting from climate change." Because the base forecast includes climate change, all of the IRP analysis reflects impacts related to climate change and a separate sensitivity to include these impacts is not necessary. Refer to Appendix A for additional regarding how climate change is incorporated into the base load forecast.

The Alternative Lowest Reasonable Cost portfolio, described in Volume I , Chapter 8, is defined to be the portfolio of resources that would occur, but for CETA clean energy obligations.[29] This is a fully integrated portfolio that optimizes resource selections across all states' requirements but does not necessarily meet CETA clean energy standards starting in 2030. The portfolio is still determined under SCGHG for Washington resource selection.

Figure O.5 presents the cumulative (at left) and incremental (at right) portfolio changes between the alternative lowest reasonable cost and preferred portfolios. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The only significant change is a 780 MW reduction in renewable wind resources included in the alternative lowest reasonable cost portfolio. This shows that a large portion of the renewable wind resources included in the early window of the preferred portfolio is driven by the need to comply with CETA clean energy obligations.

[29] WAC 480-100-620(10)(a).

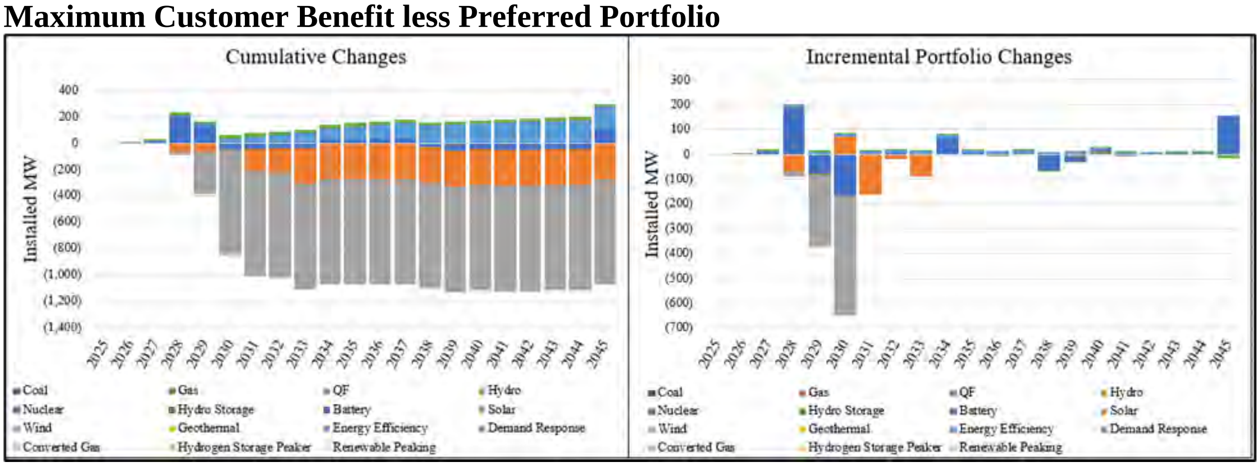
**Figure O.5 – Cumulative and Incremental Portfolio Changes, Alternative Lowest Reasonable Cost less Preferred Portfolio**




The Maximum Customer Benefit portfolio, described in detail in Chapter 8, prioritizes the addition of demand response and energy efficiency in Washington and removes Yakima and Walla Walla transmission options. As a result, over 1 GW of small-scale renewables are added to Washington as a replacement for utility-scale options.

Figure O.6 presents the cumulative (at left) and incremental (at right) portfolio changes between the maximum customer benefit and preferred portfolios. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The maximum customer benefit portfolio includes 172 MW of energy efficiency incremental to the preferred portfolio and a reduction of 801 MW of wind resources. Not shown in Figure O.6 is the large shift from utility-scale solar to small-scale solar. The maximum customer benefit portfolio includes 1,429 MW of incremental small-scale solar and a reduction of 1,429 MW of utility-scale solar in Walla Walla and Yakima.

**Figure O.6 – Cumulative and Incremental Portfolio Changes, Maximum Customer Benefit less Preferred Portfolio**



## Clean Energy Targets

RCW 19.405.040 and 19.405.050 set the 2025, 2030, and 2045 targets for electric utilities in Washington to meet. Specifically, utilities must show that by December 31, 2025, all coal-fired resources have been removed from Washington's allocation of electricity. By January 1, 2030, utilities must be greenhouse gas neutral, and by 2045, Washington's electric utilities must be 100% renewable or non-emitting.

RCW 19.405.090 sets out four alternative compliance pathways that can be used to meet up to 20% of the carbon neutrality standards that begin in 2030 and run through 2044:

(i) Making an alternative compliance payment under RCW 19.405.090(2);

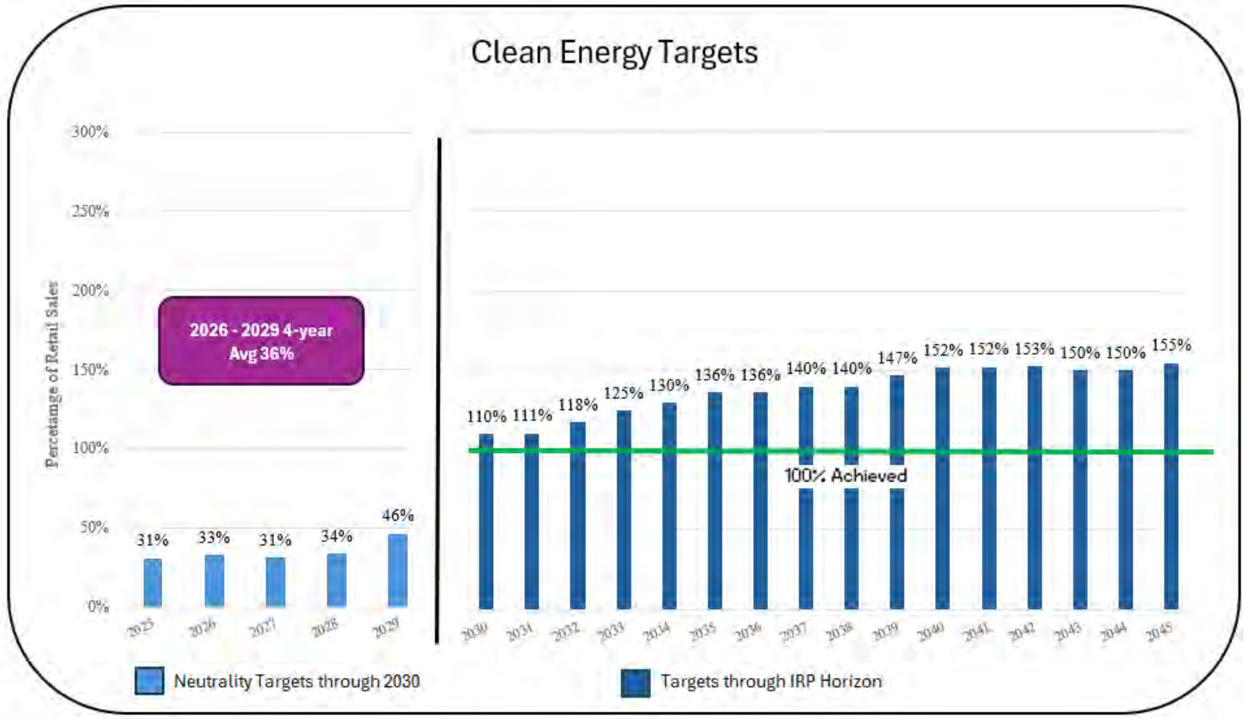
(ii) Using unbundled renewable energy credits, provided that there is no double counting of any nonpower attributes associated with renewable energy credits within Washington or programs in other jurisdictions, subject to conditions outlined in CETA;

(iii) Investing in energy transformation projects, including additional conservation and efficiency resources beyond what is otherwise required under this section, provided the projects meet the requirements of subsection (2) of this section and are not credited as resources used to meet the standard under (a) of this subsection; or

(iv) Using electricity from an energy recovery facility using municipal solid waste as the principal fuel source, where the facility was constructed prior to 1992, and the facility is operated in compliance with federal laws and regulations and meets state air quality standards, subject to conditions outlined in CETA.

The 2025 IRP preferred portfolio, optimized and dispatched under the social cost of greenhouse gas price policy for Washington customers, currently forecasts that PacifiCorp will be on track to meet the compliance requirements in 2030 and 2045, serving 110% of Washington retail sales with CETA-compliant energy by the end of 2030, as shown in Figure O.7.

**Figure O.7 -- Clean Energy Interim Targets for Washington Customers, 2025 through 2045**




Currently, PacifiCorp does not expect to use the alternative compliance payment, energy transformation project, or energy recovery facility pathway to meet the standards under RCW 19.405.090. Depending on the annual weather conditions, meeting targets for 2030 may require the use of unbundled renewable energy credits, though impacts of annual variation are likely to be closer to normal levels when evaluated over the four years of the first compliance period.

Table O.3 reports updated interim targets for the Company's second CEIP planning period for the years 2026-2029, reported as annual megawatt hours of energy rather than as percentages.

**Table O.3 – Clean energy interim targets for Washington customers 2026-2029**

| | 2026 | 2027 | 2028 | 2029 | Total |
|---|---|---|---|---|---|
| Retail Electric Sales (Adjusted)[1] | 4,023,917 | 4,160,614 | 4,297,349 | 4,268,516 | 16,750,396 |
| Projected Renewable and Nonemitting Energy | 1,310,620 | 1,306,196 | 1,443,155 | 1,978,179 | 6,038,150 |
| **Net Retail Sales** | 2,713,297 | 2,854,418 | 2,854,194 | 2,290,338 | 10,712,246 |
| Target Percentage | 33% | 31% | 34% | 46% | |
| **Interim Clean Energy Target** | 1,310,620 | 1,306,196 | 1,443,155 | 1,978,179 | 6,038,150 |

[1]Retail electric sales less qualifying facilities generation

While the 2025 IRP and this CEAP must include a 10-year clean energy action plan, and the preferred portfolio presents a pathway to compliance with CETA's 2030 energy standards, the IRP is a steppingstone to the 2025 CEIP filing later this year. Refinements and additional analysis completed as part of the CEIP process might lead to changes in the portfolio results for Washington. The clean energy interim targets present here are used to verify and assess that compliance is being achieved and planned for in the IRP process, but do not at this stage represent final targets for the next CEIP planning period. Near-term interim targets, and other specific targets and actions (for demand-side management resources), will be included in the 2025 CEIP.

Additionally, while the near-term interim targets do not show a drastic increase in the acquisition of new clean energy resources before 2029, as compared to between 2029 and 2030, this a product of the modeling assumptions. CETA targets are binding as of 2030, and unless resources prices are expected to be significantly cheaper in the near-term, the model generally finds a just-in-time approach to be least-cost. However, the company recognizes the potential risks of this strategy and is open to procuring resources in amounts higher than what is indicated in this IRP action plan if resources are economic and available to come online before the end of 2029. The latest completed cluster study results show potential of over 1 GW of non-emitting resources in the queue and located in Washington that could readily serve our service area, some of which have commercial operation dates before the end of 2028. These resources include solar, solar and storage, a battery storage, and a wind project.

## Customer Benefits

Washington statute RCW 19.405.040(8) states that

> "an electric utility must, consistent with the requirements of RCW 19.280.030 and 19.405.140, ensure that all customers are benefiting from the transition to clean energy: Through the equitable distribution of energy and nonenergy benefits and reduction of burdens to vulnerable populations and highly impacted communities; long-term and short-term public health and environmental benefits and reduction of costs and risks; and energy security and resiliency."

PacifiCorp presented its initial development of a customer benefit indicators (CBI) framework in its inaguaral 2021 CEIP by identifying three key components to be answered: 1) identify key communities who are experiencing disprorpationate challenges, 2) pinpoint chalenges that can be reduced or improved by the utility and clean energy resources, and 3) develop metrics to track progress relative to those challenges and benefits.[30] With each planning cycle, PacifiCorp has continued to refine and expand upond its initial CBI framework, and continues to do. Most notably, the company has redefined its definition and measurement of vulnerable populations and has added several CBIs and metrics to its framework since 2021. The most current CBI framework, reflective of these iterative updates and improvements, and in response to settlement conditions from the Revised 2021 CEIP, is depicted in the section that follows.

## Customer Benefit Indicators

Table O.4 provides PacifiCorp's current customer benefit indicators (CBIs) framework and associated metrics.

**Table O.4. – PacifiCorp's CBI Framework**

| No. | CBI | Benefit Categories | Metric(s) |
|---|---|---|---|
| 1 | Increase culturally and linguistically responsive outreach and program communication including increased availability of translation services for all PacifiCorp Programs, including credit, collection, and payment. | Reduction of burdens<br>Non-energy benefits | a. Number of topics addressed in outreach in non-English languages |
| | | | b. Number of impressions from non-English outreach |
| | | | c. Percentage of responses to surveys in Spanish |
| | | | d. Number of programs for which PacifiCorp provides translation services or translated material<br>e. Number of languages PacifiCorp uses for translated material |
| 2 | Increase community-focused efforts and investments | Non-energy benefits<br>Reduction of burden<br>Public health | a. Number of workshops on energy related programs<br>b. Headcount of staff supporting program delivery in Washington who are women, minorities, and/or can show disadvantage[a]<br>c. Number of public charging stations in Named Communities |
| 3 | Increase participation in company energy and efficiency programs and billing assistance programs | Cost reduction<br>Reduction of burden<br>Non-energy benefits<br>Energy benefits | a. Number and percentage of households/businesses, including Named Communities, who participate in company energy/efficiency programs |
| | | | b. Dollar value of energy efficiency expenditures[b] |
| | | | c. Number and percentage of households that participate in billing assistance programs |
| | | | d. Number and percentage of households/businesses who participate/enroll in demand response, load management, and behavioral programs |
| | | | e. Dollar value of demand response, load management, and behavioral programs expenditures |

[30] Pg. 27, PacifiCorp's 2021 Revised CEIP filed in docket UE-210829 is available online at: https://apiproxy.utc.wa.gov/cases/GetDocument?docID=277&year=2021&docketNumber=210829

| No. | CBI | Benefit Categories | Metric(s) |
|---|---|---|---|
| 1 | Increase culturally and linguistically responsive outreach and program communication including increased availability of translation services for all PacifiCorp Programs, including credit, collection, and payment. | Reduction of burdens<br>Non-energy benefits | a. Number of topics addressed in outreach in non-English languages |
| | | | b. Number of impressions from non-English outreach |
| | | | c. Percentage of responses to surveys in Spanish |
| | | | d. Number of programs for which PacifiCorp provides translation services or translated material<br>e. Number of languages PacifiCorp uses for translated material |
| | | | f. Number of residential appliances and equipment rebates provided to Named Community customers (where known) |
| | | | g. Number of residential rebates provided to customers residing in rental units |
| | | | h. Investment and/or energy efficiency savings in rental residential housing stock |
| 4 | Increase efficiency of housing stock and small businesses, including low-income housing | Energy benefits | a. Number of households and small businesses that participate in company energy/efficiency programs |
| | | | b. Dollar value of energy efficiency expenditures[b] |
| 5 | Increase renewable energy resources and reduce emissions | Environmental | a. Amount of renewables/non-emitting resources serving Washington |
| | | | b. Amount of Washington allocated greenhouse gas emission from Washington allocated resources |
| 6 | Decrease households experiencing high energy burden | Cost Reduction of burden | a. Number and percent of customers experiencing high energy burden by: highly impacted communities, vulnerable populations, low-income bill assistance (LIBA) and Low-Income Weatherization participants, and other residential customers; and average excess burden per household. High energy burden is defined as greater than or equal to six percent of household annual income. |
| 7 | Improve indoor air quality | Public health<br>Non-energy benefits | a. Number and percent of households using wood as primary or secondary heating |
| | | | b. Number and percent of non-electric to electric conversions for Low-Income Weatherization program |
| 8 | Reduce frequency and duration of energy outages | Energy resiliency<br>Risk reduction<br>Energy benefits | a. SAIDI, SAIFI, CAIDI and CEMI[c] scores (rolling 7-year average) at area level including and excluding major events |

| No. | CBI | Benefit Categories | Metric(s) |
|---|---|---|---|
| 1 | Increase culturally and linguistically responsive outreach and program communication including increased availability of translation services for all PacifiCorp Programs, including credit, collection, and payment. | Reduction of burdens<br>Non-energy benefits | a. Number of topics addressed in outreach in non-English languages<br>b. Number of impressions from non-English outreach<br>c. Percentage of responses to surveys in Spanish<br>d. Number of programs for which PacifiCorp provides translation services or translated material<br>e. Number of languages PacifiCorp uses for translated material |
| 9 | Reduce residential customer disconnections | Energy security | a. Number and percentage of residential electric disconnections for nonpayment by month, measured by location and demographic information (zip code/census tract. known low-income (KLI) customers, Vulnerable Populations (where known), Highly Impacted Communities, and for all customers in total)<br>b. Residential arrearages as reported pursuant to Commission Order 04 (Appendix A Third Revised Term Sheet, Section J, Part 8 a-c) |

| No. | CBI | Benefit Categories | Metric(s) |
|---|---|---|---|
| 1 | Increase culturally and linguistically responsive outreach and program communication including increased availability of translation services for all PacifiCorp Programs, including credit, collection, and payment. | Reduction of burdens<br>Non-energy benefits | a. Number of topics addressed in outreach in non-English languages<br>b. Number of impressions from non-English outreach<br>c. Percentage of responses to surveys in Spanish<br>d. Number of programs for which PacifiCorp provides translation services or translated material<br>e. Number of languages PacifiCorp uses for translated material |
| 10 | Increase Named Community clean energy | Energy benefits | a. Total MWh of distributed energy resources 5 MW and under, where benefits and control of resources accrue to members of Named Communities<br>b. Total MWh of energy storage resources 5 MW and under, where benefits and control of the resource accrue to members of Named Communities<br>c. Number (i.e., sites, projects, and/or households) of distributed renewable generation resources and energy storage resources, where benefits and control of the resource accrue to members of Named Communities, including storage/backup/emergency powered centers for emergencies.<br>d. Total MWh of energy savings from Energy Efficiency programs, where benefits and control of the savings accrue to members of Named Communities<br>e. Where known, for a), b), c), and d) above, PacifiCorp will specify whether the Named Community resources are highly impacted communities (HIC) and/or vulnerable population and KLI |

[a] In this metric, program delivery is defined as related to energy efficiency programs, with exception to the low-income weatherization program.
[b] Energy efficiency expenditures include customer, partner, and direct install incentive payments and exclude all other administrative or program costs.
[c] System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), Customer Average Interruption Duration Index (CAIDI), Customers Experiencing Multiple Interruptions (CEMI).

## Non-Energy Benefit and Impacts

Since the 2021 IRP and inaugural 2021 CEIP, PacifiCorp has been expanding the ways it incorporates NEIs into its program planning. One key enhancement in the 2025 IRP is PacifiCorp's use of measure-specific NEI results rather than a flat proxy adder. The measure-specific results are provided by DNV who contracted with PacifiCorp to conduct a detailed and comprehensive NEI assessment. The company has shared out this research to stakeholders through DSM Advisory Group meetings and has leveraged these inputs in the updated CPA.[31] Another enhancement has been to bring the discussion of NEIs into the context of the Biennial Conservation Plan (BCP) in conjunction with the DSM Advisory Group. Additionally, for demand response, a literature review was conducted to determine if there were any program-specific NEIs that could be leveraged. Since no quantitative values were found in the literature review, PacifiCorp chose to include a 10% adder to approximate NEI impacts for demand response. Moving forward, PacifiCorp plans to continue conducting research on NEIs.

Several of the CBIs identified in the above CBI framework are intended to capture some form of non-energy benefits or impacts, as described in the third column of Table O.4. For example, CBIs 1, 2, 3 and 7 are intended to capture several different dimensions of potential NEIs. These CBIs continue to be tracked and applied to appropriate business and program decisions.

## Identifying Vulnerable Populations

Consistent with the settlement agreement reached in the 2021 CEIP,[32] PacifiCorp met with a combination of Washington interested parties and advisory group members in three workshops to review and improve the company's approach to identifying and tracking vulnerable populations. These workshops also considered multiple vulnerability factors that were set forth in Condition 14 of the settlement agreement.

The first of these workshops occurred in June 2024, which discussed Condition 14, the company's process of identifying and tracking vulnerable populations and highlighted peer utility approaches to identifying and tracking vulnerable populations.

The second vulnerable population workshop unveiled a modified vulnerable population geographic approach, which incorporated vulnerable population criteria as provided by Equity Advisory Group input and included settlement vulnerability factors.

The third vulnerable population workshop incorporated feedback received from the second vulnerable population workshop into the modified vulnerable population geographic methodology,

[31] Refer to the "2025 CPA - Appendix E - WA Non-Energy Impact Mapping" as part of the CPA supplemental materials posted on the website, which maps the accrual of NEIs to various groups of measures available to customers consistent with WAC 480-100-620(13): https://www.pacificorp.com/energy/integrated-resource-plan/support.html

[32] The Washington Utilities and Transportation Commission by order 06 in docket UE-2109829 approved the Full Multi-Party Settlement Agreement and approved PacifiCorp's Revised 2021 CEIP, subject to the conditions in the settlement agreement. Available online at: https://apiproxy.utc.wa.gov/cases/GetDocument?docID=592&year=2021&docketNumber=210829

which included the addition of several new vulnerability criteria. The modified vulnerable population methodology was adopted by the company in January 2025.[33]

The company's modified vulnerable population geographic methodology replicates the Washington Department of Health (WDOH) – Highly Impacted Community (HIC) methodology and uses a percentile ranking approach for the census tracts located within Pacific Power's Washington service area. Unlike WDOH, Pacific Power's vulnerable population geographic methodology uses a total of 38 criteria to determine if a census tract is vulnerable, rather than the 19 criteria used by WDOH.

The company's newly adopted vulnerable population geographic methodology results in 36 out of the total 61 census tracts in the Washington service area as being considered vulnerable, whereas the WDOH HIC approach results in a total of 20 census tracts being vulnerable. There is an overlap of 19 census tracts that are considered vulnerable in both methodologies, resulting, a total of 37 census tracts in the Washington service area are now considered vulnerable when either methodology is applied.

## Specific Actions

CETA requires utilities to pursue all cost-effective, reliable, and feasible conservation and efficiency resources, and demand response; maintain and protect the safety, reliable operation, and balancing of the electric system; and ensure that all customers are benefiting from the transition to clean energy through the equitable distribution of energy and nonenergy benefits and reduction of burdens to vulnerable populations and highly impacted communities; long-term and short-term public health and environmental benefits and reduction of costs and risks; and energy security and resiliency.

### Supply-side

PacifiCorp will issue, as supported by the 2025 IRP and CEAP, a Request for Proposals (RFP) to procure resources aligned with the 2025 IRP preferred portfolio and in compliance with Washington laws, regulations and obligations that can achieve commercial operations by the end of December 2029. The company is also refining and expanding its use of a non-price scoring methodology to consider energy equity and relevant CBIs in its valuation and scoring of bids.[34]

### Demand-side

#### Energy Efficiency Actions

CETA requires that the utility set a four-year conservation target for the current CEIP planning period covering years 2026 through 2029. The 2025 IRP CETA-compliant portfolio, inclusive of all Washington requirements, identified cost-effective, reliable, and feasible resources for

[33] The final vulnerable populations methodology was summarized and presented in a public CEIP meeting on January 29, 2025, meeting materials including the slides, notes and a recording can be found online at https://www.pacificpower.net/community/washington-clean-energy-transformation-act-equity.html.

[34] Pacific Power provided an introduction to the concepts of energy justice in its RFP process at a CEIP engagement meeting on March 25, 2025. The company will continue to refine this methodology and seek input and feedback from its advisory group members and other interested parties.

informing the end-use efficiency portion of Washington's 2026-2027 Energy Independence Act (EIA) conservation target. The actual targets will be documented in the 2026-2027 Biennial Conservation Plan. These 2026-2027 targets will be included in the 2026-2029 Clean Energy Implementation Plan and the targets for 2028-2029 will initially be the same as for years 2026-2027 until the 2028-2029 Biennial Conservation Plan is complete and can provide an update to the outer year targets. PacifiCorp will also revisit prior CEIP energy efficiency utility actions to consider updates to the methodology for vulnerable populations and its application.

**Demand Response Actions**

PacifiCorp will also use the 2025 IRP CETA-compliant portfolio as the starting point to determine the 2026-2029 target for its demand response portfolio. The final target may be modified from the IRP results based on PacifiCorp's internal assessment of potential growth by individual programs, and consultation with program administrators.

PacifiCorp has been in the process of substantially revising and expanding its portfolio of demand response programs in Washington going into 2025. PacifiCorp continues to implement its plan in the 2022-2025 CEIP through the launch of three new residential programs. At the same time, the company has been leveraging lessons learned from implementation in 2023 and 2024 to improve the overall performance of existing programs. In addition to these actions, PacifiCorp will take the following steps to inform the specific targets for demand response to be peresnted in the 2026-2029 CEIP:

- Establish 2026-2029 demand response target based on the final 2025 IRP CETA-compliant portfolio, and individual program forecasts
- Estimate impact to date and likely future impact of planned and existing programs on HICs and vulnerable populations
- Review individual programs to consider potential additional actions to increase delivery of program benefits to named communities

Additional information regarding PacifiCorp's near-term actions, both incorporating these supply-side and demand-side specific actions and broader actions to support community engagement, CBI development, and other regulatory requirements are described in the final section in this appendix.

## Public Participation Plan

PacifiCorp will file its next CEIP Public Participation Plan (PPP) to the Washington Utilities and Transportation Commission on or before May 1, 2025. The PPP is a document that provides information on the various tools and tactics the company has developed, or is in the process of developing, for its public engagement spaces, utilizing feedback captured through its various public engagement channels and feedback tracker. PacifiCorp's public participation strategy for the 2025 CEIP will continue to build upon the following four pillars that support robust and inclusive participation: (1) Engaging members of the public with appropriate outreach, methods, timing, and language considerations; (2) Addressing barriers to participation; (3) Making data accessible and available to members of the public and CEIP interested parties; and (4) Incorporating learnings from existing advisory groups.

PacifiCorp takes pride in being able to offer a robust menu of stakeholder engagement opportunities through its various meeting spaces. Each meeting space is unique in its design, group goals, target audience and the prioritization of topics. This ensures there is wide coverage among groups and topics and that PacifiCorp can offer an engagement option for all. Meeting spaces are open to all, drawing a wide array of audience members from Washington-interested parties, community-based organization representatives to members of the general public. Within each space, PacifiCorp strives to create a safe atmosphere where all participants can engage in constructive dialogue, ask questions, and provide feedback. Participants have the opportunity to learn about different clean energy implementation plan topics and information and can expect various opportunities and methods to collaborate throughout the year. PacifiCorp's engagement meeting spaces support an engagement ecosystem that offers an option for each type of participant so that they may engage with the company when and where it makes sense for them to do so.

PacifiCorp will continue to adapt its CEIP public participation process to ensure that it is open, transparent, and accessible. The company will further embrace inclusive design and aim for communication with interested persons to be proactive and easy to understand.

## Action Plan

Table O.5 describes actions relevant to PacifiCorp's Washington Clean Energy Action Plan is a format consistent with the broader systemwide action plan presented in Chapter 10 (Action Plan). Each action item is categorized and described in a manner that can be tracked from one filing to the next.

**Table O.5 – Washington Clean Energy Action Plan Matrix**

| Action Item | Existing Resource Actions |
|---|---|
| **1a** | **System Action Plan Items:**<br>• Refer to Chapter 10 (Action Plan) for general action items relevant to the 2025 IRP. |
| | **New Resource Actions** |
| **2a** | **2025 Washington-situs RFP:**<br>• PacifiCorp will issue, as supported by the 2025 IRP and CEAP, a Request for Proposals (RFP) to procure resources aligned with the 2025 IRP preferred portfolio and in compliance with Washington laws, regulations and obligations that can achieve commercial operations by the end of December 2029.<br>**Transmission:**<br>• PacifiCorp will also continue to analyze and pursue transmission projects for Washington, as appropriate, to support resources needed for serving Washington load, reliability, and meeting CETA objectives. |
| | **Demand-Side Management Actions** |
| **3a** | **Energy Efficiency**<br>• Pacific Power will submit the 2026-2027 Biennial Conservation Plan (BCP) by November 1, 2025.<br>• Pacific Power will include 2026-2029 energy efficiency targets in the 2025 CEIP, in addition to revisiting energy efficiency utility actions to consider updates such as to the methodology for capturing vulnerable populations. |

| | |
|---|---|
| **3b** | **<u>Demand Response</u>**<br>• Establish 2026-2029 demand response target based on the final 2025 IRP CETA-compliant portfolio and individual program forecasts<br>• Estimate impact-to-date and likely future impacts of planned and existing programs on HICs and vulnerable populations<br>• Review individual programs to consider potential additional actions to increase delivery of program benefits to named communities |
| | **Community Engagement** |
| **4a** | **<u>Public Participation Plan</u>**<br>• Pacific Power will file its next CEIP Public Participation Plan on or before May 1 of 2025. The Public Participation Plan provides an update on and forward look of Pacific Power's public participation engagement activities in Washington. |
| **4b** | **<u>Equity Advisory Group</u>**<br>• PacifiCorp streamlined the number of Equity Advisory Group (EAG) meetings to complement the menu of Clean Energy Implementation Plan meetings which will be available in 2025. The company proposed a schedule which includes 9 sessions of Equity Advisory Group (EAG), 3 of which are combined meetings with other Washington advisory groups.<br>• Annual May One-on-Ones<br>  o Build upon existing relational partnerships; meeting the Equity Advisory Group members where they are in community<br>  o Share updates and resources with one another<br>  o Gain exposure to the different cultures within Pacific Power's service area and through authentic encounters, identify emerging barriers and opportunities to community energy program participation<br>• Tooling and retooling advisory group members for increased participation and greater clarity.<br>• Creating a repository of 101 level topic/concept presentations and recordings.<br>• Design and deliver presentations which support and foster meaningful engagement and shared understanding.<br>• Filling in the picture; bring in guest presenters, such as utility commission staff to deliver Regulatory 101 presentations.<br>• Grow membership in the advisory group to balance representation from service districts and communities.<br>• Collaborate with the communications team to improve web presence and usability of the Pacific Power website<br>• The advisory group members will have opportunity to contribute perspective and guidance on elements of the following reports and filings:<br>  o PacifiCorp 2025 Clean Energy Implementation Plan |

| | |
|---|---|
| | o PacifiCorp 2025 Public Participation Plan<br>o PacifiCorp Integrated Resource Plan through the Public Input Process<br>o PacifiCorp Conservation Potential Assessment for 2025-2044 |
| | **Community Benefit Indicators** |
| **5a** | • Pacific Power has proposed two new CBI metrics: $SO_2$ and $NO_x$ and will continue to solicit input and feedback from its advisory groups and interested parties and finalize the proposed metrics |
| **5b** | • Pacific Power will continue to make progress on its CBI framework, identifying any refinements to its current CBIs and proposed metrics to work towards establishing a baseline and a transparent framework to apply to resource procurement, planning, and other business decisions, as relevant. |
| | **Regulatory Actions** |
| **6a** | **2025 Clean Energy Implementation Plan**<br>• Pacific Power will file its 2025 Clean Energy Implementation Plan (CEIP) with the Washington Utilities and Transportation Commission on October 01, 2025, with a draft provided for interested parties to review and submit comments 45 days before filing. |
| **6b** | **Other CETA-related filings**<br>• Pacific Power will file its 2025 CEIP progress report on July 1, 2025, reporting on progress made towards its clean energy targets. |

# APPENDIX P – OREGON CLEAN ENERGY UPDATE

## Introduction

PacifiCorp's 2025 Integrated Resource Plan presents a fully compliant approach to meeting Oregon obligations through long-term resource planning, near-term actions, and ongoing evaluation and execution. This appendix presents model outcomes, narratives, and reports on progress to bridge the evolution from 2025 IRP systemwide analytics to the upcoming 2025 Clean Energy Plan.

In the biannually filed IRP, the company calculates an optimal resource mix for Oregon compliance under HB 2021, evaluating risks, costs, benefits, and continual progress against targets. In years where a full IRP is not filed, the company evaluates its planning and progress toward targets through an IRP Update. Both reports present annual positions for utility and small-scale resources, energy efficiency and demand response, and project the least-cost, least-risk strategy for the achievement of clean energy targets.

The optimization modeling used by PacifiCorp incorporates all state requirements, including those associated with HB 2021, evaluating the type, size, location, and timing of resources on a proxy basis.

In Oregon's share of the 2025 IRP preferred portfolio, significant renewable additions of 6,499 MW, of which 1,147 MW are projected to be small-scale or community-based renewable energy, are supported by 3,819 MW of energy storage. This promotes the achievement of clean energy targets, which in combination with PacifiCorp's large, interconnected grid and operational excellence serves to underscore reliability and resiliency.

HB 2021's influence on the preferred portfolio lowers cumulative system emissions by nearly 100 million metric tons between 2030 and 2045, demonstrating planning effectiveness. With more than two thousand model runs supporting 7 variants and 12 sensitivities, PacificCorp's 2025 IRP preferred portfolio, and particularly Oregon's share of that portfolio, confidently demonstrates progress toward "an affordable, reliable and clean electric system."

### Key findings

1. Oregon will require 763 MW of new renewable resources, 381 MW of shorter-duration batteries, and over 300 MW of demand-side management resources by the end of 2029.
2. By 2030, PacifiCorp's small-scale renewable resource obligation amounts to 675 MW of small-scale renewable capacity.
3. By 2045, Oregon's share of the preferred portfolio includes almost 6.5 GW of new renewable resources to meet its energy, capacity, and clean energy needs. This includes over 1 GW of small-scale solar resources, and an additional 3.8 GW of batteries, over 2.6 GW of which is selected as longer-duration storage. Additionally, the preferred portfolio includes 40 MW of renewable peaking resources added after 2040.
4. Oregon-allocated greenhouse gas emission fall 91.5 percent from baseline levels by 2030, 99.9 percent by 2035, and 100 percent by 2040.

## Background

In 2021, Governor Brown signed House Bill 2021 (HB 2021) into law. HB 2021 defined ambitious greenhouse gas reduction requirements for electric providers, while also directing utilities to consider how to maximize additional benefits to communities. HB 2021 requires retail electricity providers to reduce greenhouse gas emissions associated with electricity sold to Oregon consumers by: 80% by 2030; 90% by 2035; and 100% by 2040.[1]

HB 2021 lays the groundwork for the transition to a clean, reliable, and sustainable energy future, but also seeks to protect and support communities who are the most vulnerable and highly impacted by the energy transition.

In service to these emissions reduction requirements, an electric company must develop a clean energy plan (CEP) for meeting relevant targets concurrent with the development of its integrated resource plan. Fundamental to PacifiCorp's approach in building a bridge from the IRP to the CEP filing are utility and small-scale resource planning, distribution system planning, and community emphasis. Community emphasis includes community benefit indicators, community-based renewable energy, and engagement with community members through advisory groups.

The 2025 IRP presents an opportunity for stakeholders to engage with the portfolio results and offer potential refinements to the path towards these clean energy targets. This Appendix P offers a focused discussion around how the preferred portfolio is developed to comply with all Oregon obligations, and to add insight into other activities that support the company's progress towards and development of its clean energy targets.

Consistent with Order No. 25-090, Pacific Power will subsequently file its 2025 Clean Energy Plan with the Public Utility Commission of Oregon on June 30, 2025. The 2025 CEP is expected to align with modeling inputs, assumptions and results presented in this IRP, but will expand on these analyses with additional narrative, analytics, and action plans. While the 2025 IRP preferred portfolio presents a path to comply with HB 2021 emissions standards, this portfolio is still a representation based on proxy resources and modeling assumptions. Additional information or considerations could impact the timing and pace of resource selection and greenhouse gas reduction over the next two decades. The 2025 CEP will include additional elements regarding Oregon-specific portfolio sensitivities, cost impacts to Oregon customers, and other elements considered under HB 2021.

The sections below discuss PacifiCorp's portfolio assumptions and results for Oregon-specific resources, including small-scale renewables, greenhouse gas emissions, and transmission resources, and detail additional actions and resources necessary to PacifiCorp's operations and resource options in the state, including demand-side management, community-based renewable energy, distribution system planning, and transportation electrification. The document concludes with a discussion of PacifiCorp's community and stakeholder engagement processes, community benefit indicators, and action plan to implement the findings from the 2025 IRP.

[1] ORS 469A.410.

# Portfolio Assumptions

The 2025 IRP process serves as the basis for developing and identifying a long-run portfolio and near-term action plan that will put the company on a path towards compliance with HB 2021 greenhouse gas reduction targets, the small-scale renewable target, and to ensure reliable and cost-effective service for customers.

Refer to Volume I, Chapter 3 for an overview of environmental policy regulation, including Oregon state policies. Chapter 6 presents the base load forecast and existing resources represented in modeling. Chapter 7 presents a complete list of proxy resource options available for endogenous selection. Chapter 8 explains each step involved in the development and evaluation of resource portfolios. Chapter 9 includes the preferred portfolio and list of specific resources selected to meet Oregon's compliance requirements and reliability needs.

## Portfolio Integration and Resource Allocations

Since the filing of the 2023 IRP and CEP, PacifiCorp has made strides in its modeling process, particularly regarding the consideration of multiple and competing state obligations. The IRP process inherently represents a systemwide approach and produces a systemwide preferred portfolio. In its inaugural CEP, PacifiCorp layered on HB 2021 considerations after a systemwide optimized portfolio was created, which led to concerns that HB 2021 compliance was not appropriately analyzed and could not be complied with in addition to other state policies.

The process of "portfolio integration" in the 2025 IRP is a methodology that optimizes each state's requirements, obligations, and resource needs, and then integrates each into a single portfolio of proxy resource selections. Every final integrated portfolio variant and sensitivity, unless otherwise stated, reflects the optimized set of proxy resource selections to meet all state obligations. Relevant here, the 2025 IRP preferred portfolio of resources represents a set of resources optimized to achieve HB 2021 compliance, as well as all other state requirements that PacifiCorp is subject to. Refer to Volume I, Chapter 8 for additional details of this portfolio integration process.

It is important to note that the 2025 IRP includes assumptions regarding resource cost-allocation. In lieu of a multi-jurisdictional cost allocation protocol that extends past the 2020 Protocol (set to expire December 31, 2025), all existing resources are assumed to be allocated (both in terms of costs and generation) in accordance with the 2020 Protocol indefinitely.[2] In most cases, this means existing resources are allocated to Oregon customers based on a forecast of their system-generation (SG) factor, which is determined based on their relative jurisdictional load. In some instances, like for qualifying facilities (QFs) or special customer contract resources, existing resources are situs-allocated (100 percent) to Oregon customers. Regarding new proxy resource selections, it is assumed that any new proxy resources selected to serve Oregon need are situs allocated, including both supply-side and demand-side resources.[3] These resource allocation assumptions underlie progress toward HB 2021 clean energy targets and Oregon-allocated greenhouse gas emissions, as explained below.

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[2] The 2020 Protocol was adopted by the Public Utility Commission of Oregon order no. 20-024 on January 23, 2020 (available online at https://edocs.puc.state.or.us/efdocs/HAA/um1050haa161935.pdf.).

[3] The only "proxy" resource selected in the 2025 IRP that is considered a system resource and is allocated based on system generation factors is the Natrium nuclear demonstration project.

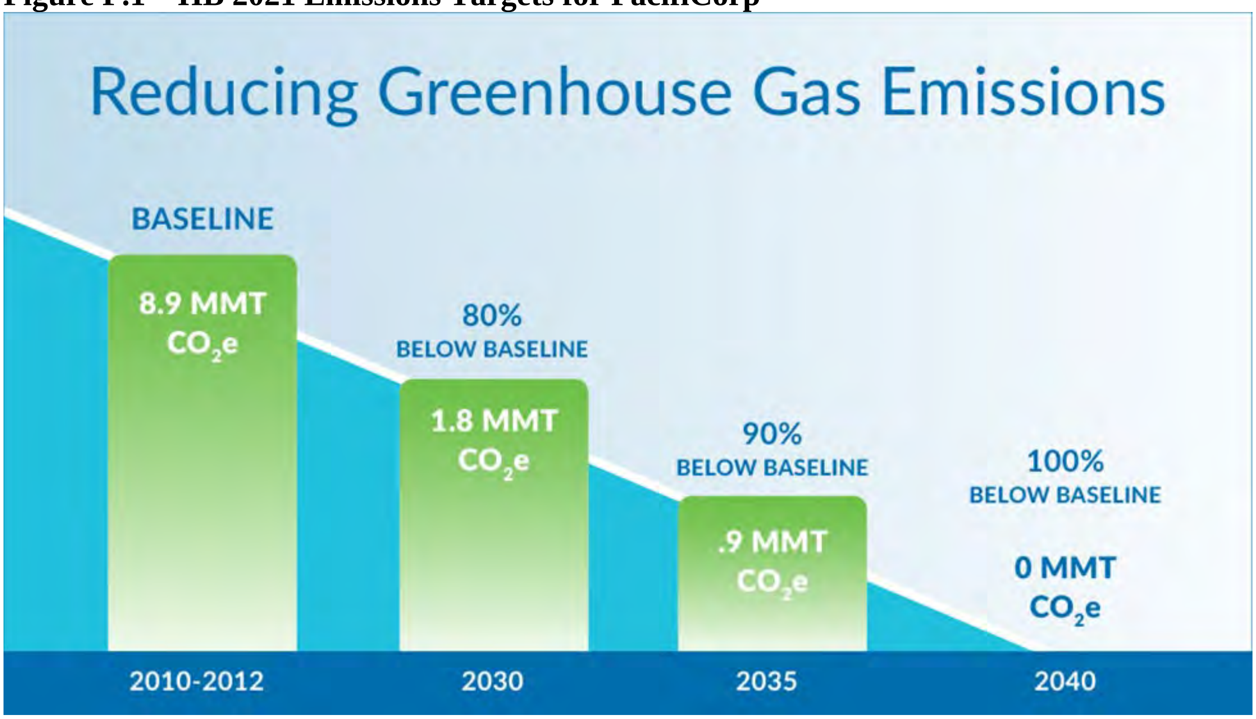
### Resource Adequacy

As described in Volume I, Chapter 8, the 2025 IRP helps ensure resource adequacy for the system and by state by requiring each portfolio to include sufficient resources to be compliant with the Western Resource Adequacy Program (WRAP), both in aggregate and for the loads and resources specific to the jurisdiction under evaluation. In addition, portfolios must be able to meet hourly load requirements without significant energy shortfalls, and the iterative portfolio development process increases planning requirements within the long-term (LT) capacity expansion model to account for shortfalls identified within the more granular short-term (ST) model that includes hourly dispatch outcomes.

### HB 2021 Greenhouse Gas Emissions: Methodology and Assumptions

HB 2021 directs the state's large investor-owned utilities to incrementally reduce greenhouse gas emissions from baseline emissions associated with retail electricity sales. Baseline emissions are defined as the average annual emissions of greenhouse gases for the years 2010, 2011, and 2012 associated with the electricity sold to retail electricity consumers, as reported to, and established by the Oregon Department of Environmental Quality (ODEQ). The ODEQ's determination, measured in million metric tons of carbon dioxide (MMT $CO_2e$), and corresponding emissions reductions for each target year, are reflected in Figure P.1 below.

**Figure P.1 – HB 2021 Emissions Targets for PacifiCorp**




PacifiCorp calculates its greenhouse gas emissions for purposes of determining HB 2021 progress according to applicable statutes, rules, and written guidance published by ODEQ. ODEQ is responsible for measuring and verifying the greenhouse gas emissions that are included in a utility's CEP and reporting these findings to the commission. Consistent with these responsibilities, ODEQ published guidance for projecting and reporting emissions for HB 2021 that leverages methodologies from the agency's longstanding Greenhouse Gas Reporting Program under OAR 340, Division 215.[4] In addition, ODEQ has published guidance that directs the utilities to use unit and resource specific emission factors and default emission factors for the 2025 CEP.[5] In addition to emissions factors, ODEQ provided guidance for multi-jurisdictional utility reporting, adjusting for netting wholesale sales or non-retail electricity, accounting for transmission losses, and accounting for electricity purchased from specified and unspecified sources.[6]

Table P.1 below provides detailed descriptions of the assumptions and authorities PacifiCorp relied on when determining total forecasted utility emissions for compliance with HB 2021.

**Table P.1 – Assumptions**

| Category | Assumption and Authority |
|---|---|
| Baseline Emissions | In May 2022, ODEQ established PacifiCorp's baseline emissions levels, and emissions reductions necessary to achieve PacifiCorp's emissions reduction requirements.[7] PacifiCorp believes that ODEQ may have established an incorrect baseline emissions level. However, the company relies on the DEQ's determination in the 2025 IRP, without conceding its accuracy. |
| General Calculation Methodology | PacifiCorp's initial calculation of projected emissions, prior to any exclusions or special treatment, is based on Oregon's long-standing Greenhouse Gas Reporting framework established in OAR 340-215 for annual actual emissions reporting. ORS 469A.420(1)(b), 468A.280. |
| Emission factor for existing specified resources | ODEQ assigns emission factors to PacifiCorp's existing facilities, by unit, based on historical data. The DEQ assigned emission factors are available online. |
| Emission Factors for future resources | In cases where a facility or unit-specific emission factor is either not available or applicable, DEQ directs utilities to use default emission factors by fuel type. When possible, these emission factors are based on U.S. Environmental Protection Agency's (EPA) 2022 Greenhouse Gas Emission Factors hub, which is available on the EPA's website. When not available, emission factors from EPA's 2020 Emissions & Generation Resources Integrated Database (eGRID) Technical |

[4] OAR 340-215-0010 through -0125; Oregon Department of Environmental Quality, "GHG Emissions Accounting for House Bill 2021 Reporting and projecting emissions from electricity using DEQ methodology" (available at https://www.oregon.gov/deq/ghgp/Documents/HB2021EFGuidance.pdf).
[5] Oregon Department of Environmental Quality, "Greenhouse Gas Emission Factors for HB 2021 Electricity Sector Emission Projections" (available at https://www.oregon.gov/deq/ghgp/Documents/HB2021-EmissionFactors.xlsx).
[6] Oregon Department of Environmental Quality, "Multi-jurisdictional Utilities: Instructions for reporting greenhouse gas emissions" (available at https://www.oregon.gov/deq/aq/Documents/GHGRP-MutlijurisdictionalProtocol.pdf).
[7]

| | |
|---|---|
| | Guide were used. ODEQ's default emission factors are available online. |
| Emissions for planned coal-to-natural gas converted resources | Pursuant to OAR 340-215-0040(4) a utility may petition ODEQ to approve in writing an alternative calculation or method for determining an emission factor, providing an explanation and rationale for the alternative.<br><br>On March 20, 2025, DEQ approved PacifiCorp's petition to use an alternative calculation method for determining the emission factor for planned coal-to-natural gas converted resource. PacifiCorp will use an emissions adjustment multiplier of 0.578 $MTCO_2e$/megawatt-hour, applied to the DEQ published unit specific emissions rate for coal fired resources that are planned to convert to natural gas. PacifiCorp's alternative is more conservative than DEQ's published default emission factors for natural gas fired resources and estimates higher emissions from converted coal-to-gas units based on more accurate operational assumptions and lower efficiency of converted units. |
| Emission factors for unspecified resources | The default emission factor is 0.428 $MTCO_2e$/megawatt-hour for energy originating from an unspecified source. This includes purchases from centralized market purchases such as the Western Energy Imbalance Market. OAR 340-215-120(2)(a). |
| Transmission Losses | Electricity suppliers must include a 2 percent transmission loss correction factor when calculating emissions from generation not measured at the busbar. OAR 340-215-120(1)(b)(B)(i). |
| Removal of non-retail sales | According to ODEQ guidance, energy, and emissions from the sale of wholesale power are not included in annual Oregon emissions totals. Rather, a utility must remove the energy and emissions associated with those non-retail sales from its calculations and reporting of emissions associated with the electricity the utility supplied to its Oregon retail customers. Utilities may account for non-retail sales with 3 approaches, based on the nature of each individual sale:<br><br>1) Sales of specific power: Non-retail sales of a specific resource or set of resources are accounted for by removing that power and any associated emissions from a utility's emissions reported to ODEQ. |

| | |
|---|---|
| | 2) Sales of unspecified power: Unspecified power purchased by a utility and then re-sold to non-retail customers is removed (both the power and emissions) from the amount of unspecified power included in a utility's emissions reported to ODEQ.<br><br>3) Sales of the utilities' overall resource mix: Non-retail sales of a utility's power, without specification of any particular portion of the utility's portfolio, are removed by proportionately subtracting it across the utility's overall resource mix for that year.<br><br>ODEQ Guidance: GHG Emissions Accounting for House Bill 2021, Reporting, and projecting emissions from electricity using DEQ methodology |
| Multi-state jurisdictional reporting | Oregon rules allow for multi-jurisdictional utilities like PacifiCorp to rely upon a cost allocation methodology approved by the Oregon PUC for allocating emissions associated with the generation of electricity that serves Oregon customers. OAR 340-215-0120(6)(c).<br><br>PacifiCorp's most current multi-jurisdictional cost allocation methodology approved by the Oregon commission is the 2020 Protocol. While the 2020 Protocol does not extend through the planning horizon of the 2025 CEP, the Company relies on this allocation methodology for the planning horizon.<br><br>Under the currently approved cost allocation methodology, the utility reports a percentage of its entire multi-state system emissions based on the share of the power served in Oregon.<br><br>Under all cost allocation structures, it is assumed that no coal is allocated to Oregon starting in 2030 consistent with ORS § 457.518, and that no thermal resources or market purchases are allocated to Oregon starting 2040.<br><br>ODEQ Multijurisdictional Utilities, Instructions for Reporting Greenhouse Gas Emissions and OAR 340-215-0120. |
| Exclusions | Emissions from qualified facilities under the terms of the Public Utility Regulatory Policies Act (PURPA) and net metering programs are not |

| | |
|---|---|
| | regulated under HB 2021, and emissions from these sources are excluded from ODEQ's determination of relevant emissions. Yet the MWh associated with these resources remain included in the calculation. ORS 469A.435(3). |

## Small-scale Renewables

In addition to establishing greenhouse gas emissions reduction requirements, HB 2021 also amended Oregon's small-scale renewable mandate included in ORS 469A.210, by postponing compliance with the law until 2030, and increasing the target to 10 percent of PacifiCorp's aggregate electrical capacity, from the prior 8 percent.

To determine PacifiCorp's SSR target, the company identified Oregon-allocated aggregate electrical capacity in each year 2030 onwards and calculated a 10 percent small-scale requirement based on that capacity. As shown in Table P.2 below, the 10 percent small-scale target in 2030 amounts to 675 MW. To address this need, the 2025 IRP preferred portfolio includes a slight excess of small-scale resource capacity at 723 MW total SSR-qualifying resources, which is comprised of existing SSR-eligible resources and future proxy resources.

PacifiCorp estimates it has 403 MW of existing resources in its nameplate capacity that fit the definition of SSR. This leaves an additional need for 272 MW of small-scale proxy resources to meet the target of 675 MW.[8] This assumes that all eligible QFs that expire before 2030 renew at 100 percent nameplate capacity, which is slightly above the 75 percent historical renewal rate. The 2025 IRP preferred portfolio includes slightly more small-scale proxy resources, at 320 MW, providing a small buffer to better ensure compliance.

**Table P.2 – Small-scale Resource Position in 2030**

| Oregon Small-Scale 2030 | Nameplate (MW) | Credit/ (Requirement) (MW) | Notes |
|---|---|---|---|
| **Existing Resources** | | | |
| All Resources | 3784 | (378) | Small-scale requirement is 10% of existing nameplate |
| Small-scale | 403 | 403 | Existing small-scale eligible resources |
| Surplus/(Need) | 27 | 25 | Excess existing small-scale resources* |
| **Exstisnig + Incremental Proxy Resources** | | | |
| All Resources | 6754 | (675) | Small-scale requirement is 10% of total nameplate |
| Small-scale | 723 | 723 | Total small-scale eligible resources |
| Surplus/(Need) | 53 | 48 | Excess small-scale resources* |

[8] This ten percent standard includes small-scale capacity in both the numerator (megawatts of small-scale generating capacity), and in the denominator (megawatts of all generating capacity). As a result, even though the small-scale capacity is 48 megawatts higher than the requirement of 675 MW, 53 megawatts of small-scale capacity could be removed from the preferred portfolio while remaining in compliance, as the total capacity for all resources following this modification (6,701 MW) would have a lower small-scale capacity requirement (670 MW).

# Portfolio Results

The sub-sections below discuss the 2025 IRP system and Oregon-specific resource selections, resulting greenhouse gas emissions, and transmission and small scale and CBRE results.

## Oregon Resource Selections

All portfolio results from the 2025 IRP are presented in Volume I, Chapter 9, including both system and Oregon-specific resource selections.

Table 9.2, specifically, shows the Oregon-allocated megawatts (MW) of resources selected in the preferred portfolio. Table P.3 recasts the same information that is presented in Chapter 9, Table 9.2 but delineates which incremental proxy resource selections for Oregon are considered situs, or 100 percent allocated to Oregon customers because they are selected only for Oregon need, versus Oregon's share of a systemwide proxy resource. As the table shows, all resource selections, except for the single nuclear resource category, are assumed to represent situs-allocated resources for Oregon.

## Table P.3 - Incremental resource additions for Oregon customers, by resource allocation assumption

| Incremental resource additions for Oregon, by resource type and year | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Installed Capacity, MW | | | | | | | | | | | | | | | | | | | | | |
| **Situs proxy resources** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** | **2034** | **2035** | **2036** | **2037** | **2038** | **2039** | **2040** | **2041** | **2042** | **2043** | **2044** | **2045** | **Total** |
| 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 Peaking | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 19 | - | 4 | - | 18 | 40 |
| 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 |
| | | | | | | | | | | | | | | | | | | | | | | - |
| **System-shared proxy resources** | | | | | | | | | | | | | | | | | | | | | | - |
| Nuclear | - | - | - | - | - | - | - | 130 | - | - | - | - | - | - | - | - | - | - | - | - | - | 130 |

In the near-term, the 2025 IRP preferred portfolio selects 763 MW of new renewable resources to serve Oregon customers by the end of 2029, including 461 MW of utility-scale wind and 302 MW of utility-scale solar resources. The portfolio also includes over 380 MW of battery storage coming online in the same time period. Additionally, the portfolio optimizes DSM resources, picking 64 MW of new demand-response and 305 MW of energy efficiency resources by the end of 2029.

Between 2030 and 2035, the portfolio includes an additional 3.7 gigawatts (GW) plus of renewable resources. This includes 1,222 MW of utility-scale wind and 2,065 MW of utility-scale solar, plus 417 MW of small-scale solar resource additions. During these years, there is also significant additional storage selected: over 800 MW including both longer-duration batteries (over 24 hours) and traditional shorter-duration batteries (under 8 hours) of 360 MW and 516 MW, respectively. These years see a slightly smaller increase in new demand-response capacity, with only 19 MW added, whereas energy efficiency selections increase by 669 MW. During this time frame, a system nuclear resource of 500 MW nameplate capacity is also added, which Oregon customers would receive a share of equivalent to 130 MW.

By the end of the 21-year planning horizon, over 2.2 GW of wind resources, 3 GW of utility-scale solar and over 1.1 GW of small-scale solar are added to serve Oregon customers. Additionally, 3.8 GW of storage resources are added, including both shorter and longer-duration batteries. The portfolio also selects nearly 2 GW of energy efficiency selections and 153 MW of demand-response by the end of the period. This long-term portfolio of resources represents a pathway to meet energy needs, resource adequacy requirements and clean energy targets for Oregon. And, importantly, these Oregon incremental resources are in addition to the system resources identified in the 2025 IRP that will be allocated to serve Oregon customers.

## Greenhouse Gas Emissions

As described in the previous section, PacifiCorp relies on ODEQ methodologies to forecast its HB 2021 emissions based on its IRP results. The integrated portfolio methodology incorporated HB 2021 emissions reduction targets as part of Oregon's compliance obligations, ensuring they are met through a least-cost, least-risk approach. The portfolio results indicate a significant downward trend in Oregon-allocated greenhouse gas emissions, with a modest decline between 2025 and 2029, and a steeper reduction in 2030 onwards. These forecasted reductions are driven by the large addition of proxy renewable and storage resources.

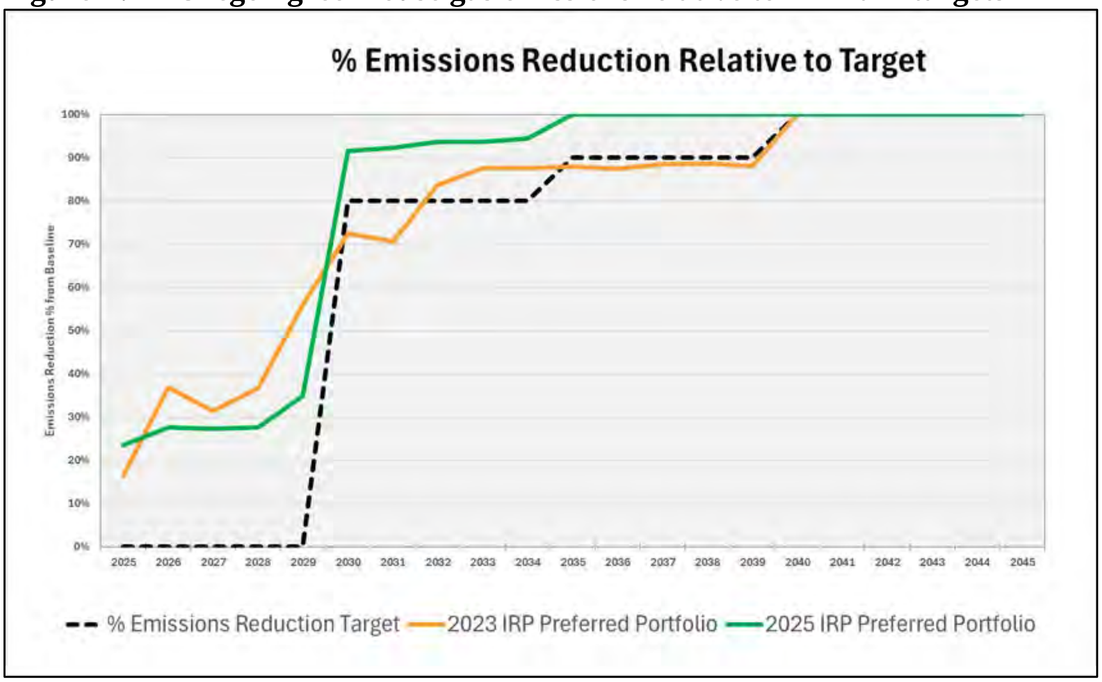
The modeling process, based on emission factors and the established methodology framework, enables the endogenous selection of proxy resources and the optimized dispatch of resources and market transactions. This approach ensures a resource portfolio that meets HB 2021 obligations for Oregon customers. Figure P.2 confirms PacifiCorp's portfolio compliance with HB 2021, though PacifiCorp notes that the resources allocated to Oregon exceed annual energy requirements. Currently, regulations do not allow the company to specify sales on an Oregon-allocated basis or by fuel type. If PacifiCorp was permitted to sell Oregon-allocated energy exceeding its annual requirements from specific emitting resources, the company could further reduce emissions, accelerate progress toward its HB 2021 targets, and lower costs for Oregon customers.

Achieving compliance with HB 2021 requires that (a) enough megawatt-hours of energy are allocated to Oregon to meet every megawatt-hour of Oregon load on an annual basis, and (b) that the emissions associated with those megawatt-hours do not exceed the emissions allowed under the emissions reduction target. Compliance with both requirements create a need for significant new non-emitting generation. Additionally, Oregon's share of existing gas plants and some gas conversions are modeled as distinct units that dispatch separately from the rest-of-system share of these units.[9]

Each Oregon jurisdictional portfolio required that the model add enough megawatt-hours of new non-emitting generation to meet a majority of Oregon load in each year after 2030, ensuring that the emissions associated with any load not met with non-emitting generation does not exceed the emissions reduction target. In addition, to represent the limit on Oregon-allocated emitting generation, a model driver dispatch price starting at $100/ton in 2030 was applied to the emissions generated by Oregon's share of gas plants.

Figure P.2 illustrates PacifiCorp's Oregon-specific greenhouse gas emissions trajectory, relative to HB 2021 defined targets, based on the 2025 IRP preferred portfolio. While the 2023 IRP preferred portfolio initially showed higher near-term emissions reductions, the 2025 IRP preferred portfolio catches up to that trajectory by 2030 and ultimately exceeds it in the pace of emissions reduction. The black dashed line represents the HB 2021 emissions reduction targets, which take effect in 2030. The 2025 IRP preferred portfolio produces a compliant pathway achieving required emission reductions from 2030 onward.[10]

**Figure P.2 – Oregon greenhouse gas emissions relative to HB 2021 targets**

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[9] This modeling assumption allows the model to dispatch Oregon-allocated of natural gas units independently from the share of the plant dispatched for other jurisdictions without a GHG constraint. This is a modeling assumption and does not represent a specific strategy to dispatch Oregon-allocated natural gas generators in a specific way. Rather, this strategy acts a proxy for various strategies, such as situs-allocation to Oregon of only a few natural gas generators which could then be dispatched with a presumed GHG constraint.

[10] See Appendix M, stakeholder feedback form #61 (Public Utility Commission of Oregon)

## Small-Scale and Community-Based Renewables

As described in a prior section and depicted in Table P.2, the 2025 IRP preferred portfolio showed a small-scale resource need of 675 MW by 2030. PacifiCorp plans to comply with the SSR targets with a mix of existing qualifying resources and new proxy small-scale resources that will be acquired, likely through requests for proposals (RFP) issued to market. As previously shown in Table P.3, significant proxy small-scale resources are added across the planning period. Small-scale resources, while required to meet the SSR target, are also available to be selected by the model to meet energy needs. A total of 1,147 MW of small-scale solar resources are selected over the planning horizon.

The company anticipates that some number of the proxy small-scale resources could be, and will be met, with community-based renewable energy (CBRE) projects. However, at the level of granularity the model possesses, there is no significant distinction between the two types of resources, other than potentially assuming some additional benefits are generated by CBREs relative to other small-scale renewables. CBREs, and the company's broader strategy to encourage and foster them is described in more detail in a later section.

## Transmission

PacifiCorp uses a transmission topology that captures major load centers, generation resources, and market hubs interconnected via firm transmission paths. 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.

In support of the renewable resource additions identified for Oregon in the 2025 preferred portfolio, PacifiCorp has identified transmission options that will reinforce existing transmission paths, allow for increased transfer capability, and will support the interconnection of new renewables. A summary of PacifiCorp's identified transmission additions serving Oregon and Oregon-allocated resources is shown in Table P.4 below:

### Table P.4 - Transmission Selections Supporting Oregon Resources[1,2]

| | | Export (MW) | Import (MW) | Interconnect (MW) | Build Investment ($m) | Build (%) | From | To |
|---|---|---|---|---|---|---|---|---|
| 2028 | Cluster 1 Area 11: Willamette Valley | 0 | 0 | 199 | 14 | 100% | n/a | n/a |
| 2028 | Cluster 1 Area 14: Summer Lake | 400 | 400 | 400 | 111 | 100% | Summer Lake | Hemingway |
| 2028 | Cluster 1/2/3: Walla Walla | 0 | 0 | 393 | 328 | 100% | n/a | n/a |
| 2028 | Serial queue: Central Oregon | 0 | 0 | 152 | 4 | 100% | n/a | n/a |
| 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 |
| 2030 | 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** | | **3,800** | **3,800** | **4,326** | **4,064** | | | |

[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 project-specific timing and some costs are project-specific.

## Impacts of Oregon Compliance

The Utah, Idaho, Wyoming, and California (UIWC) jurisdictional portfolio optimized under the medium natural gas, no carbon (MN) price-policy scenario selects a portfolio for the entire system but does not model compliance with HB 2021, so it was selected as the basis for comparison with the preferred portfolio. Given that the UIWC jurisdictional portfolio does not model compliance with Washington's Clean Energy and Transformation Act (CETA) clean energy standards, some of the differences between the UIWC portfolio and the preferred portfolio may not specifically reflect compliance associated with HB 2021.

Figure P.3 presents the differences between the resource selections in the UIWC 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. In the absence of Oregon compliance requirements (and Washington compliance requirements), the quantity of utility-scale renewable wind and solar resources included in the portfolio decreases by 5,944 MW, and the quantity of storage resources decreases by almost 2,000 MW.

**Figure P.3– Cumulative and Incremental Portfolio Changes, UIWC Portfolio Less Preferred Portfolio**

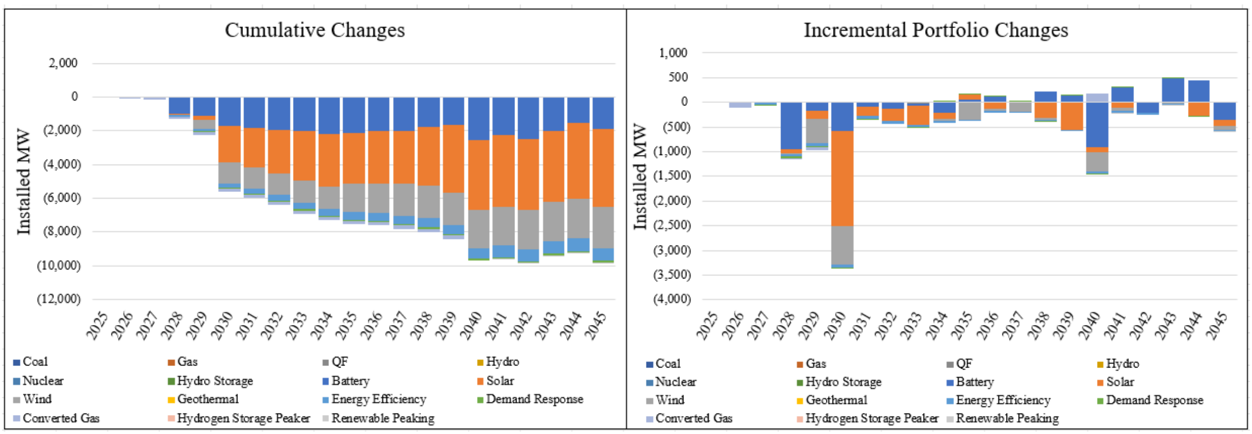



Figure P.4 compares the costs in the ST model dispatched under MN between the UIWC portfolio and the preferred portfolio. A negative value indicates that the UIWC portfolio has lower costs than the preferred portfolio. In the absence of Oregon (and Washington) compliance requirements, the UIWC portfolio is substantially cheaper than the preferred portfolio, reaching 2 billion in reduced costs by the end of the horizon. Although this difference in system costs is not fully attributable to Oregon compliance requirements, it suggests that the costs of compliance are significant. Further analysis in the 2025 CEP will assess the Oregon-allocated incremental cost of HB 2021 compliance.

**Figure P.4 – UIWC Portfolio Less Preferred Portfolio System Cost**

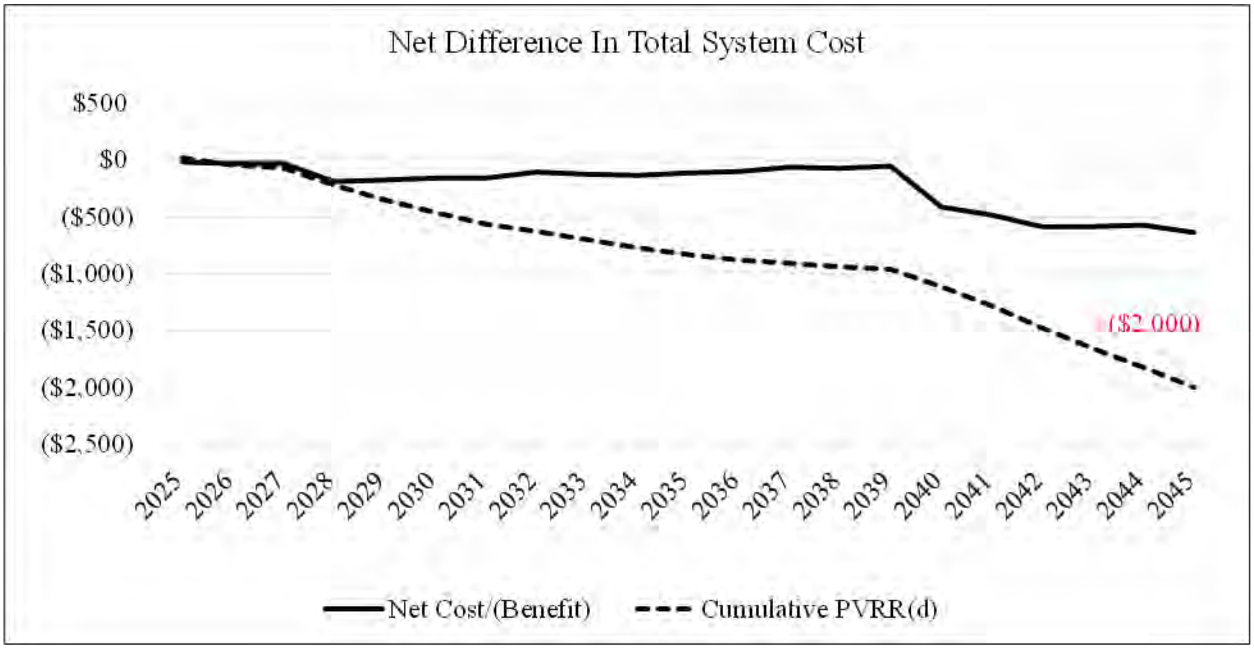
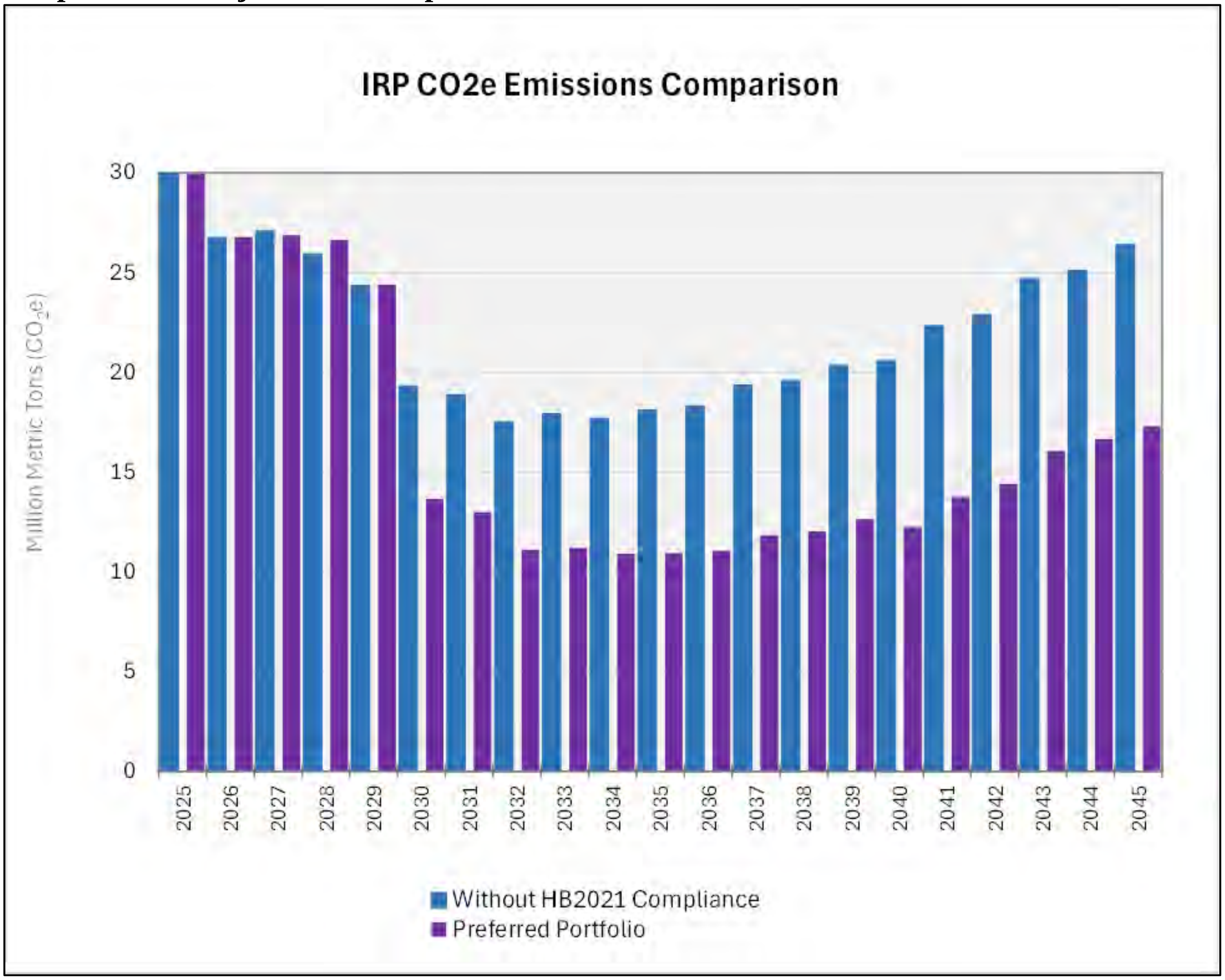



Figure P.5 compares the system emissions in the preferred portfolio to the system emissions in the UIWC portfolio. In the absence of compliance with HB2021, total portfolio emissions are significantly higher than in the preferred portfolio from 2030 onwards. This impact on emissions is a result of both HB 2021 constraints on Oregon-allocated greenhouse gas emissions but is also in-part, the result of large renewable resource additions selected to serve Washington customers. Both state-specific clean energy standards appear to drive emissions down compared to what would otherwise occur.[11]

[11] See Appendix M, stakeholder feedback form #61 (Public Utility Commission of Oregon)

**Figure P.5 – Emissions comparison of HB 2021-compliant preferred portfolio with non-compliant UIWC jurisdictional portfolio**




PacifiCorp's April 1, 2024, Planning Supplement[12] identified several strategies that could be used to reduce emissions and produce a compliant portfolio. The status of these strategies within the modeling for the 2025 IRP[13] is summarized below:

- **Existing resources:** Oregon is allocated shares of existing resources based on the 2020 Protocol that is currently in effect. This is largely unchanged since the 2023 IRP Update.
- **QF generation for compliance:** Based on discussions with the Oregon Department of Environmental Quality, PacifiCorp is now including all QF generation as non-emitting energy when evaluating its resource supply relative to Oregon load.
- **IRP selections:** the portfolio without HB 2021 compliance, discussed in Figure P.3, contains significant clean resource additions which would reduce emissions, analogous to what was identified in the 2023 IRP Update, though this is much less than what is necessary for HB 2021 compliance.

[12] PacifiCorp's Oregon Planning Supplement, date April 1, 2024. Docket No. LC-82. Available online at: https://apps.puc.state.or.us/edockets/docket.asp?DocketID=23647

[13] See Appendix M, stakeholder feedback form #61 (Oregon Public Utility Commission).

- **Additional clean resources:** The PLEXOS model selects resources based on Oregon's energy requirements and the additional clean resources allocated to Oregon in the preferred portfolio, and the additional clean resources represented in Figure P.3 ensure that Oregon's annual energy requirements are met. In the 2023 IRP Update, resources allocated to Oregon were not sufficient to meet Oregon's load on an annual basis and emissions were attributed to the shortfall based on the emissions rate for unspecified market purchases.
- **Reduce natural gas dispatch:** The inclusion of a model driver dispatch price reduces the model's relative economics for Oregon's share of gas-fired resources in 2030-2039. That driver starts at $100/ton in 2030 and escalates over time. Because it is applied on a per ton basis, units with the highest emissions rate are likely to be impacted the most, so gas conversion units would be influenced more than relatively efficient combined cycle combustion turbines. Studies to evaluate reduced dispatch drivers could improve the economics of the HB 2021 compliance portfolio, by allowing for economic generation at a level that results in emissions that are close to the required level, rather than significantly exceeding it.

  **Reduce market emissions rate:** Oregon continues to be allocated a system share of market purchases in accordance with the 2020 Protocol through 2035. Thereafter, the emissions associated with market purchases would exceed the total allowed emissions, so the associated energy and resulting emissions have not been allocated to Oregon from that point forward. Access to a (mostly) clean energy market would be necessary at that point in time and could be valuable as early as 2030.

## Additional Actions and Resources

The sub-sections below discuss additional PacifiCorp actions and resource that are not necessarily driven by the 2025 IRP process or IRP outcomes yet are nonetheless integral to the company's resource portfolio and system operations. These include PacifiCorp's actions and resources regarding: Demand-Side Management, Community-Based Renewable Energy, Distribution System Planning, and Transportation Electrification.

### Demand-Side Management

#### Energy Efficiency

The Energy Trust of Oregon (ETO) is an independent nonprofit organization dedicated to promoting energy efficiency and renewable energy solutions for customers of participating utilities in Oregon. Since 2002, PacifiCorp has collaborated with ETO to implement energy efficiency programs within its Oregon service area, in accordance with ORS 757.612 and ORS 757.054. These programs are funded through two tariffs: Oregon Schedule 291, which supports energy efficiency initiatives, and Oregon Schedule 292, which funds renewable energy efforts.

PacifiCorp maintains two agreements with ETO to facilitate this partnership:

1. The Energy Efficiency and Renewable Energy Programs Funding Agreement, which governs the allocation of collected funds to ETO for program delivery and establishes performance expectations for energy savings and renewable energy development.
2. The Consumer Information Transfer Agreement, which enables ETO to access necessary utility data to support program implementation, participation tracking, and energy savings verification.

Looking ahead to 2025, PacifiCorp will continue working with ETO to review their proposed inaugural Multi-Year Plan (MYP). This plan will establish ETO's energy efficiency targets and associated budgets for the five-year period from 2026 to 2030, ensuring alignment with statewide energy goals and utility resource planning efforts. Through this ongoing collaboration, PacifiCorp aims to support effective program delivery while ensuring cost-effective investments that benefit customers and contribute to broader energy policy objectives.

### Demand Response

PacifiCorp has been aggressively growing its demand response portfolio in Oregon for several years. The company expanded the long-running Irrigation Load Control pilot to a full customer program in 2022, and since that time has launched three additional programs targeting the commercial, industrial, and residential sectors. PacifiCorp's DR programs are carefully designed to provide a range of grid management services, while meeting the needs of the customer segment and end-use targeted. The current portfolio includes the following programs:

- Irrigation Load Control, launched in 2023, which used a program-provided load control switch for peak management during the summer season.
- Wattsmart Business Demand Response, launched in 2023, which enrolls loads at the customer meter to provide peak management, contingency reserves, or frequency response resources. Control mechanisms vary from manual control to full automation.
- Wattsmart Battery, scheduled to launch in 2025, which dispatches residential batteries for various demand response applications.
- Cool Keeper, scheduled to launch in 2025, which uses a load control switch to curtail the compressor on residential cooling equipment for peak load reduction, contingency reserve, and frequency response needs during the summer colling season.
- Wattsmart Drive, scheduled to launch in 2025, which uses EV telematics to curtail charging for demand response. This program was originally included as part of the Transportation Electrification Plan but is now managed as part of the DR portfolio.

In addition, the company offers time-of-use rates for all customer classes that contribute to our strategy to manage loads effectively.

The company expects to continue to grow this portfolio of programs as indicated by our IRP planning process. In the forthcoming 2025 CEP, PacifiCorp will establish a forecast for total capacity available through our DR portfolio based on the results of the 2025 IRP, and feedback from our partners and stakeholders.

## Community-Based Renewable Energy

Community-Based Renewable Energy (CBRE) projects are energy systems that interconnect to utility distribution or transmission assets, and may be combined with microgrids, storage systems, demand response measures, or energy-related infrastructure that promotes climate resiliency. Additionally, CBRE projects must: (1) directly benefit particular communities through community-benefit agreements or direct ownership by local government, nonprofit entities, or federally recognized Indian tribes; or (2) increase resiliency or community stability, local jobs, economic development, or direct energy cost savings to families and small businesses. A utility's Clean Energy Plan (CEP) must examine both the costs and opportunities that CBRE projects can potentially provide when determining what mix of resources are most appropriate to offset energy generated from fossil fuels.

ODOE was directed by House Bill (HB) 2021 to convene a work group to examine opportunities to encourage the development of small-scale renewable and CBRE projects, including how either could contribute to economic development and local energy resilience, as well as the potential rate impacts of developing small-scale renewables and CBRE projects. ODOE convened the workgroup in December 2021, which included a broad spectrum of representatives from various sectors and stakeholder groups and delivered its Study on Small-Scale and Community-Based Renewable Energy Projects (ODOE Study) to the Oregon Legislature in September 2022.

The ODOE work group was not able to reach consensus on specific recommendations for the study. Instead, the work group generally agreed that small-scale renewable and CBRE projects can play a role in addressing climate change, achieving state energy and climate goals, reducing impacts on land and natural resources, supporting local economic development, and providing local energy resilience for communities and organizations. While small-scale renewable and CBRE projects "can have unique benefits that are customized to meet local and community expectations and goals," the ODOE Study cautioned that the "individualized nature of these types of projects also make it difficult to provide an overarching assessment on the energy, environmental, economic, and social benefits and challenges of small-scale and community-based projects writ large." This is because these types of projects "involve trade-offs, and for small-scale and community-based projects those trade-offs will vary significantly but will also be more flexible to address community or local concerns and needs."

The ODOE Study acknowledged the "the potential for increasing rate pressure on utility customers when discussing the costs of incentivizing small-scale and community-based renewable energy project development and agreed that future policy decisions should be based on a principle of equitable distribution of costs and benefits." This is because there were "differing perspectives on the appropriateness of using regulated utility rates to pay for benefits that do not necessarily contribute to delivery of safe and reliable service at just and reasonable rates for all electricity customers." Accordingly, the ODOE Study concluded that "policymakers will need to consider the difference between economic and other societal and local benefits versus utility system benefits" when evaluating the overall value of small-scale renewable and CBRE projects in meeting the goals of HB 2021.

### Pilot Program

In advance of policy-maker outcomes stemming from the ODOE study, PacifiCorp has developed an ongoing strategy for CBREs that centers Oregon communities and is largely informed by stakeholder input. This effort is exemplified in the structure of the CBRE-RH Pilot, which advances projects in various stages of development with three separate but potentially overlapping pathways of support. For its part, a key intended outcome of the three-year Pilot is a better understanding of the true costs and quantifiable benefits of CBRE projects.

Community-Based Renewable Energy – Resilience Hub (CBRE-RH) Pilot Update: HB 2021 directed Oregon utilities to examine opportunities to encourage the development of community-based renewable energy projects, including how they can contribute to economic development and local energy resilience. PacifiCorp considered the use of a Pilot program to advance CBRE projects in its inaugural Oregon Clean Energy Plan and has since revised and refined the model. PacifiCorp filed for approval to operate this CBRE-RH Pilot within docket ADV 1637 on July 30, 2024 (Advice Letter Number 24-014). The Pilot was approved with a start date of September 20, 2024. As of the time of this writing, the utility has held 26 meetings with leaders of communities as well as project managers interested in advancing community resilience through CBRE projects. The Company has also corresponded with 17 of the 19 projects that have received ODOE C-REP construction grant awards and 9 of the 20 recipients of C-REP planning grant awards, all of whom are in various stages of development. Additionally, two letters of commitment for grant match funding have now been provided to a federally recognized Oregon Tribal Nation seeking IIJA Formula Grant funding.

**Table P.5 - Cost per kW of CBRE Projects Awarded Grant Funding by ODOE**

| Location | kW Gen | kW Storage | Grant Award | $/kW Gen |
|---|---|---|---|---|
| Mosier | 125 | 125 | $ 598,438.00 | $ 4,787.50 |
| Pendleton | 240 | 500 | $ 1,816,424.00 | $ 7,568.43 |
| Klamath Falls | 45 | 25 | $ 999,424.00 | $ 22,209.42 |
| Madras | 51 | 0 | $ 70,360.00 | $ 1,379.61 |
| Hood River | 100 | 0 | $ 500,000.00 | $ 5,000.00 |
| Gates | 61 | 125 | $ 312,852.00 | $ 5,128.72 |
| Talent | 202 | 250 | $ 1,000,000.00 | $ 4,950.50 |
| Bend | 828 | 50 | $ 1,000,000.00 | $ 1,207.73 |
| Talent | 67 | 10 | $ 116,623.00 | $ 1,740.64 |
| Madras | 1140 | 0 | $ 1,000,000.00 | $ 877.19 |
| Madras | 108 | 240 | $ 1,000,000.00 | $ 9,259.26 |
| Bend | 985 | 0 | $ 1,000,000.00 | $ 1,015.23 |
| Corvallis | 249 | 240 | $ 999,000.00 | $ 4,012.05 |
| Talent | 108 | 440 | $ 1,000,000.00 | $ 9,259.26 |
| Roseburg | 800 | 0 | $ 1,000,000.00 | $ 1,250.00 |
| Roseburg | 50 | 186 | $ 870,870.00 | $ 17,417.40 |
| Roseburg | 440 | 0 | $ 1,000,000.00 | $ 2,272.73 |
| | | | | **$ 5,843.27** |

## IRP Analysis

PacifiCorp analyzed the effects of adding 100 MW of CBRE solar projects across Oregon locations in 2030. The CBRE solar projects were assumed to operate at the same capacity factor and receive the same average locational marginal price identified in the 2025 IRP preferred portfolio for small-scale solar in Central Oregon, Southern Oregon, Willamette Valley, and Walla Walla. The cost per kW of CBRE projects awarded grant funding by ODOE, as shown in Table P.5 above, and the retail rate for the Oregon Community Solar Program were used to calculate total project costs. The table below presents the results of the analysis.

Including the CBRE solar projects in the 2025 IRP preferred portfolio is forecasted to increase the total PVRR by $181 million. In Table P.6 the column labeled "Breakeven $/MWh of Benefit" provides the minimum hourly value that would need to be assigned to the CBRE projects to make the net effect on costs zero. CBRE solar projects may provide significant benefits that are not directly considered in this analysis, including system reliability and community energy resilience.

**Table P.6 – Estimated costs Required to Breakeven on CBRE Projects**

| Year | Net Revenue ($millions) | Total Costs ($millions) | Net Benefit/ (Cost) ($millions) | Breakeven $/MWh of Benefit |
|---|---|---|---|---|
| 2030 | 4.7 | 29.0 | -24.3 | 100.6 |
| 2031 | 4.4 | 29.0 | -24.6 | 102.0 |
| 2032 | 3.5 | 28.7 | -25.2 | 105.5 |
| 2033 | 3.1 | 28.6 | -25.6 | 107.2 |
| 2034 | 2.8 | 28.4 | -25.6 | 108.2 |
| 2035 | 3.1 | 29.1 | -26.0 | 107.5 |
| 2036 | 3.0 | 29.1 | -26.1 | 107.7 |
| 2037 | 3.2 | 29.1 | -25.9 | 107.0 |
| 2038 | 3.2 | 29.1 | -25.9 | 106.7 |
| 2039 | 3.0 | 29.1 | -26.2 | 108.1 |
| 2040 | 3.8 | 29.1 | -25.4 | 103.7 |
| 2041 | 4.1 | 29.2 | -25.0 | 102.1 |
| 2042 | 5.0 | 29.1 | -24.1 | 98.7 |
| 2043 | 5.9 | 29.1 | -23.3 | 95.5 |
| 2044 | 6.2 | 29.1 | -22.9 | 93.7 |
| 2045 | 6.2 | 28.9 | -22.7 | 93.5 |

## Distribution System Planning

Distribution System Planning (DSP) was first approved in 2019 under UM 2005. On November 13, 2024, revisions to the DSP guidelines were approved. PacifiCorp will submit its updated filing by March 31, 2025. The goal of DSP is to promote transparency and inclusion by fostering a shared understanding with stakeholders regarding the current state of distribution systems and near- and long-term plans, including the exploration of nontraditional solutions. As part of this process, we will host four stakeholder workshops, all of which are open to the public. Workshop dates and materials will be sent in advance to our mailing list and posted on our website. These workshops will provide an opportunity to share information and gather feedback. Workshop dates, materials, recordings of past sessions, and an option to join our mailing list are available on PacifiCorp's Oregon Distribution System Planning webpage.[14]

[14] Review the Oregon DSP webpage online at https://www.pacificpower.net/community/oregon-distribution-system-planning.html.

## Transportation Electrification

PacifiCorp filed its 2023-2025 Transportation Electrification Plan (TEP) in May of 2023.[15] The Public Utility Commission of Oregon approved the final TEP in July 2023.[16] Over the last two years, PacifiCorp has been delivering a portfolio of programs and pilots that offer a range of support to different sectors working towards transportation electrification. This included support for residential, commercial, and multifamily customers as well as customers pursuing electrification of fleets and medium-duty vehicles (MDVs) and heavy-duty vehicles (HDVs), collectively referred to as MHDVs. The following is a summary of ongoing transportation electrification efforts and programs:

- Electric Vehicle Supply Equipment (EVSE) Rebate Pilot Program. Launched in June of 2022, this program delivers rebates to residential, income-eligible, commercial, and multifamily customers to install Level 2 chargers within residences, workplaces, and multifamily units. At the end of 2024, over 1400 rebates have been issued.
- Outreach and Education Pilot Program. Provides future Electric Vehicle (EV) drivers with greater awareness and understanding of the benefits of electric transportation through work force development, dealership engagement, outreach and educational platforms, ride, and drive events and more. This program was also launched in June of 2022.[17]
- Grant Programs. Pacific Power has distributed more than $6.5 million in Electric Mobility Grants to Oregon communities since 2020. PacifiCorp facilitates grants that support projects that advance electric transportation in underserved communities—a combination of competitive grants, matching grants, and grant writing funded through Oregon Clean Fuels Program.[18]
- Fleet Make Ready Pilot Program. Offers a behind-the-meter (BTM) custom incentive to fleet customers that will support all make-ready infrastructure focused on commercial customers and inclusive of all vehicle class types and launched in early 2024.
- Public Utility-Owned Infrastructure Pilot Program. Launched in Q3 of 2023, PacifiCorp will deploy utility-owned publicly available charging infrastructure located in underserved communities.
- Residential Managed Charing Pilot Program. Actively manages electric vehicle loads through vehicle-and charger-enable protocols to shift charging load to off-peak times and anticipated to launch in Q2 of 2025.

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[15] Pacific Power. (May 2023). Pacific Power Final Oregon Transportation Electrification Plan. edocs.puc.state.or.us/efdocs/HAH/um2056hah104112.pdf

[16] Order No. 23-257 (2023). Pacific Power Oregon Transportation Electrification Plan. Available online at: https://apps.puc.state.or.us/orders/2023ords/23-257.pdf

[17] Advice No. 21-016. (2021). (Docket No. ADV 1288/Advice No. 21-016) New Residential Charging Pilot (Schedule 117), New Nonresidential Charging Pilot (Schedule 118), and Extension of the Outreach and Education Pilot. ADV 1288 21-016 Eff 8-25-2021 filed 7-20-21 RA3_signed.pdf (state.or.us)

[18] UM 1826. (2017) Staff Investigation Electric Utility Participation in Clean Fuels. State of Oregon: Public Utility Commission of Oregon

# Community and Stakeholder Engagement

## Advisory Groups

In addition to PacifiCorp's IRP community and stakeholder engagement processes, PacifiCorp's Community Benefits and Impacts Advisory Group and Tribal Nations Community Benefits and Impacts Advisory Group members advise the company on elements related to its Clean Energy Plan and other plans and programs. Matters of importance as expressed across engagement spaces by members include:

- Costs and potential bill increases are the primary concerns, alongside the transition to cleaner energy, and advisory groups are committed to addressing these challenges. Many participants are also concerned about the dependability of renewable resources and the potential impact of materials required for clean energy technology.
- Advisory group members have expressed a need to see input in the advisory space translated into action or meaningful community benefits.
- Partnerships are key to advancing actions for greater community benefits and include the sharing of general program information and program opportunities for greater accessibility.
- More information and learning tools are needed to support a shared and foundational understanding of utility systems and the regulatory environment.
- A more transparent and user-friendly way forward is needed for members to understand the intersections of regulatory processes.
- Access to funds to add capacity for participation in programs and offerings resulting from clean energy planning is a continued need.

When PacifiCorp filed its initial engagement strategy with the Commission on April 21, 2022, the company proposed a hybrid stakeholder engagement model that relied on existing engagement processes related to the IRP process and developed new processes through the formation of an Oregon equity advisory group (CBIAG). The company's vision for moving forward is to continue a single state-wide engagement group representing the lived experiences and perspectives of communities and customers within our service territory—the CBIAG.

Through the CBIAG, PacifiCorp plans to continue seeking direct stakeholder feedback to build an inclusive and accessible process for consultation and collaboration. This includes increasing participation from communities that have not traditionally participated in utility planning processes, providing the company with a better understanding of community needs and perspectives, identifying barriers to participation and providing input on how to address these barriers, acting as a conduit to exchange information and ideas between the company and stakeholder communities, and assisting with community outreach.

The CBIAG consists of 10 individuals and/or organizations representing the lived experiences, interests, and perspectives of the communities and customers within PacifiCorp's Oregon service territory. Consistent with the definition of Environmental Justice communities within HB 2021, communities identified for inclusion/representation include communities of color, communities experiencing lower incomes, tribal communities, rural communities, coastal communities, communities with limited infrastructure, and other communities traditionally underrepresented in public processes and adversely harmed by environmental and health hazards, including seniors, youth, and persons with disabilities.

PacifiCorp also developed and formed a Tribal Nations Community Benefits and Impacts Advisory Group series, which supports and fosters collaboration, consultation, and shared understanding of Federal, State, and local programs, policies, and grants. The engagement series was formatted by informed feedback from outreach to Oregon Tribal members with whom PacifiCorp had an existing relationship and through new Tribal Nations relationship building. PacifiCorp plans to directly engage Tribal communities located within/connected to the company's service in conversations about the most effective means of obtaining their input when preparing for a clean energy future. PacifiCorp agrees that robust consultation with sovereign Tribal governments and communities is critical to understanding each Tribe's concerns and perspectives. As the scale of service and associated relationships varies between PacifiCorp and the Tribes it serves, understandably, there will likely be varied levels of engagement.

PacifiCorp continues delivering the Oregon Tribal Nations Engagement Series, focusing on equity and a clean energy future in Oregon per Oregon House Bill 2021. Through this external engagement and informational series, we plan to continue seeking direct feedback to build an inclusive and accessible process for consultation and collaboration. Through engagement with interested parties, PacifiCorp intends to continue seeking direct feedback to build an inclusive and accessible process of dialogue and cooperation.

## General Stakeholder Engagement

Leading up to the filing of PacifiCorp's first clean energy plan, the company identified the need to initiate a complementary and educational CEP engagement series to support existing engagements and to more intentionally provide the time and space to dive into key clean energy planning topics. Although PacifiCorp has various dedicated engagement spaces that support clean energy planning engagement, the CEP engagement series was developed to focus on PacifiCorp's Oregon CEP filing and regulatory requirements.

The CEP engagement series is designed to provide access to a more technical audience that is actively engaged in PacifiCorp's clean energy planning and integrated resource planning processes, so that PacifiCorp can directly solicit feedback on elements of the company's plan. Oregon CEP engagement series meetings have drawn participation from different groups such as the Public Utility Commission of Oregon Staff (Staff), environmental and justice advocates, members of PacifiCorp's CBIAG and Tribal Nations CBIAG, community-based organization representatives and general members of the public. The CEP engagement series continues through 2025, to socialize PacifiCorp's CEP and to provide additional opportunities for community and stakeholder input on elements of the plan. Unless communicated otherwise, CEP engagement series meetings are recorded for expanded accessibility and notes from each meeting are shared on

Pacific Power's Oregon CEP webpage in both English and Spanish following each individual session.[19]

As PacifiCorp approaches its next clean energy plan cycle, it will continue to offer engagement opportunities to connect and provide feedback on key CEP topics and other related areas of interest. Additionally, engagement activities will continue to adapt in response to input and learnings to further inclusion, accessibility, and the collaboration of diverse participating audiences.

## Community Benefit Indicators

As discussed in the 2023 Clean Energy Plan, Community Benefits Indicators (CBIs) are designed to demonstrate the impact of PacifiCorp's proposed programs, actions, and investments. PacifiCorp defines CBIs as the desired outcome that utility actions could either incentivize, influence, or cause. Each CBI identifies a desired outcome, while metrics allow for PacifiCorp to monitor progress at achieving these outcomes. Each CBI presented in the table below has been grouped into one of five categories, which are defined below.

- Resilience (System & Community): Resilience refers to the ability of power systems to endure and quickly restore power delivery to customers after significant disruptions. These disruptions can include deliberate attacks, accidents, or natural events like earthquakes or catastrophic wildfires. Producing resilience metrics at the census tract level can help to demonstrate how resilient PacifiCorp's system is at a community-level and support development of resilience programs that target vulnerable communities.
- Health and Community Well-Being: Access to energy is crucial for meeting basic human needs. For instance, utility disconnections may occur when customers prioritize other essentials, such as rent, food, or prescription medications, overpaying utility bills. Monitoring disconnections by census tract can help identify communities facing challenges in maintaining their well-being.
- Environmental Impacts: Reducing emissions improves air quality, leading to better health outcomes for communities by reducing respiratory illnesses and other pollution-related diseases. Tracking emissions will help PacifiCorp meet HB 2021 targets and monitor the impact of its power generation activities on communities, particularly those that are vulnerable.
- Energy Equity: Energy equity is the concept that all members of society should be able to afford and have access to a necessary and basic supply of energy. Tracking metrics like energy burden and energy efficiency program accessibility can help the company develop support mechanisms for vulnerable customers to reduce the financial strain that may be imposed by the transition to clean energy.
- Economic Impacts: Tracking the economic impacts of its clean energy investments helps PacifiCorp ensure that projects support equitable benefits for all communities. These include, for example, local job creation, workforce development and increased spending on diverse businesses.

Table P.7 depicts PacifiCorp's interim CBI framework. This CBI framework was initially presented in the 2023 CEP but continues to be reevaluated and expanded upon. This framework is

[19] Pacific Power's CEP engagement series information can be found online at https://www.pacificpower.net/community/oregon-clean-energy-plan.html.

not considered final as the company continues to work out what are the best CBIs and metrics that can be tracked by the utility and that represent significant impacts to communities.

**Table P.7 – Interim CBI Framework**

| CBI Category | CBI | Metric(s) |
|---|---|---|
| Resilience (System & Community) | Improve resilience of vulnerable communities during energy outages | SAIDI, SAIFI and CAIDI at area level including major events |
| | Reduce frequency and duration of energy outages | Energy Not Served (ENS) |
| Health and Community Well-Being | Decrease residential disconnections | Number of residential disconnections by census tract |
| Environmental Impacts | Increase energy from non-emitting and renewable resources | Amount of Oregon-allocated renewable and non-emitting energy (MWh) |
| | Reduce $CO_2$ equivalent emissions | Amount of Oregon $CO_2$ equivalent emissions, MT $CO_2e$ |
| | **PROPOSED** - Reduce $SO_2$ and $NO_x$ emissions | Amount of $SO_2$ and $NO_x$ emissions produced [20] |
| Energy Equity | Decrease proportion of households experiencing high energy burden | Average energy burden by census tract |
| | Increase housing and small business energy efficiency for vulnerable communities | Average energy burden for low-income customers, bill assistance participants and Tribal members |
| | Reduce barriers to participation in energy efficiency programs for vulnerable communities | Count of customers participating in business and residential incentive programs |
| Economic Impacts | DSM program delivery staff and grants | Headcount of DSM program delivery staff and grants awarded |
| | Public charging stations | Count of public charging stations installed in PacifiCorp territory |
| | Pre-apprenticeship and educational program participation | Headcount of participants in pre-apprenticeship programs |
| | Resource development workforce | Headcount of local and state workers during facility construction |
| | Diverse business expenditures | Spend on Disadvantaged Business Enterprise (DBE), tribal, women, minority, and/ or veteran-owned resources during facility construction |

[20] Already reported to United States Environmental Protection Agency (EPA) under the Clean Air Markets Program Data (CAMPD) program and as part of PacifiCorp's Environmental, Social, and Governance (ESG) reporting.

From the above CBI framework, most of the CBIs are considered informational, or qualitative, and can be tracked over a measure of time to help indicate if the company's collective and long-term actions are improving benefits to the communities it serves. Some of the CBIs are considered portfolio CBIs in that they can be specifically quantified based on IRP portfolio results and can help inform portfolio selections or impacts across sensitivities. The CBIs under the "resilience" category are specific to Community Based Renewable Energy (CBRE) projects that are discussed further in the next section.

Portfolio CBIs that can be quantified and reported from portfolio outcomes are energy not served (ENS), Oregon-allocated emissions (CO2e, SO2 and NOx), and Oregon-allocated renewable energy.[21] In the forthcoming 2025 CEP filing, PacifiCorp will present a broader range of portfolio sensitivities and results with an Oregon-allocated costs, benefits and nonenergy outcomes as represented by the portfolio CBIs.

Additionally, PacifiCorp continues to progress its use of nonprice scoring methodologies to incorporate the use of relevant CBIs in future bid evaluation and selection for new supply-side resources.

## Action Plan

The 2025 IRP, Volume I, Chapter 10 presents a near-term action plan identifying steps that PacifiCorp will take over the next two-to-four years to deliver resources in the preferred portfolio. This action plan includes action items for existing resources, new resources, transmission, DSM management resources, short-term firm market purchases, and the purchase and sale of renewable energy credits (RECs).

The action matrix in Table P.8 is an Oregon-specific view that expands upon the systemwide action plan to include other actions that broadly support the company's progress and fulfillment of HB 2021 goals, such as community and stakeholder engagement, activities related to CBIs, and forthcoming regulatory filings and actions.

**Table P.8 – Oregon Clean Energy Plan Action Matrix**

| Action Item | Existing Resource Actions |
|---|---|
| **1a** | **Natural Gas Emissions Compliance Strategies:**<br>• 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.[22] |

[21] The CBIs tracking local pollution emissions outcomes, specifically sulfur dioxide (SO2) and nitrogen oxides (NOx), are recently proposed CBIs that would be additions to PacifiCorp's CBI framework. These new CBI metrics were introduced in a recent CEP engagement meeting and will be workshopped with advisory group members and other interested parties before being finalized.
[22] This action is repeated from 2025 IRP, Volume I, Chapter 10 – Action Plan.

| | |
|---|---|
| | **New Resource Actions** |
| **2a** | **Small-scale renewables RFP:**<br>• PacifiCorp will issue as supported by the 2025 IRP, a small-scale renewable resource specific Request for Proposals.<br>• PacifiCorp will continue to investigate, develop, and pursue other strategies, as outlined in its SSR Acquisition Strategy filed concurrently with this IRP, to increase its small-scale and community-based resources.<br>**Transmission:**<br>• PacifiCorp will also continue to analyze and pursue transmission projects for Oregon, as appropriate, to support resources needed for serving Oregon load, reliability, and meeting CEP objectives. |
| **2b** | **2025 Oregon-situs RFP:**<br>• PacifiCorp will issue, as supported by the 2025 IRP, a Request for Proposals to procure resources aligned with the 2025 IRP preferred portfolio and in compliance with Oregon laws, regulations and obligations that can achieve commercial operations by the end of December 2029. |
| | **Demand-Side Management (Actions)** |
| **3a** | **Energy Efficiency**<br>• In 2025, PacifiCorp will continue collaborating with the Energy Trust of Oregon (ETO) to review their proposed inaugural Multi-Year Plan (MYP) that will establish their energy efficiency targets and corresponding budgets for the next five-year period (2026-2030).<br>• Though ETO implements energy efficiency within PacifiCorp's Oregon service area, PacifiCorp will continue supporting those program efforts and endorses their aim to deliver cost-effective benefits to our customers. |
| **3b** | **Demand Response**<br>• PacifiCorp will continue to expand its portfolio of DR programs in 2025, both by growing the available capacity in existing programs and launching new programs.<br>• In the 2025 update to the Clean Energy Plan, PacifiCorp will set annual goals and milestones for actions the company will take to grow available capacity in the demand response portfolio.<br>• In 2025, PacifiCorp will review individual programs to consider potential additional actions to continuously improve delivery of programs. |
| | **Community-Based Renewable Energy Actions** |
| **4a** | • PacifiCorp is considering a Blue Sky Grant Program "Go-Back" strategy.<br>• PacifiCorp will track additional pathways and opportunities to stack benefits and dovetail support for CBREs (e.g.: HB 2066, ODOE Solar+Storage Rebate expansion, ODHS OREM Resilience Hub Grant Program) |
| | **Community Engagement** |
| **5a** | **Advisory Groups**<br>• Pacific Power has sixteen planned Community Benefits and Impacts Advisory Group (CBIAG) sessions in 2025. Eight of these will be |

| | |
|---|---|
| | specifically offered to the Tribal Nations Community Benefits and Impacts Advisory Group and will include an update on various elements of the Clean Energy Plan. |
| **5b** | **<u>CEP Engagement Series</u>**<br>• Pacific Power will continue to offer Oregon Clean Energy Plan Engagement Series meetings, with four regular sessions scheduled in 2025, with opportunity for additional special meetings as requested or required, as an avenue for expanded learning and dialogue on key clean energy planning topics. |
| | **Community Benefit Indicators** |
| **6a** | • Pacific Power has proposed two new CBI metrics: SO2 and NOx and will continue to solicit input and feedback from its advisory groups and interested parties and finalize the proposed metrics |
| **6b** | • Pacific Power will continue to make progress on its CBI framework, identifying any refinements to its current CBIs and proposed metrics to work towards establishing a baseline and a transparent framework to apply to resource procurement, planning, and other business decisions, as relevant. |
| | **Regulatory Actions** |
| **7a** | **<u>Rulemaking Engagement</u>**<br>• Pacific Power will engage with ODEQ in any upcoming relevant rulemakings to address changes to the methodology and calculations of greenhouse gas emissions for purposes of demonstrating progress towards clean energy targets. Under current ODEQ rules, if Pacific Power's generation exceeds load, specified sales must reflect a proportionate share of the system, not individual resources. However, the ability to demonstrate compliance with clean energy targets through the specified sales of emitting resources may have additional benefits for Oregon customers. |
| **7b** | **<u>2025 Clean Energy Plan:</u>**<br>• Pacific Power will file its 2025 Clean Energy Plan (CEP) with the Public Utility Commission of Oregon on June 30, 2025[23] |

[23] The Public Utility Commission of Oregon issued order no. 25-090 on March 5, 2025 granting Pacific Power an extension to file its 2025 Clean Energy Plan 90 days after the 2025 IRP (available online at https://apps.puc.state.or.us/orders/2025ords/25-090.pdf.)

# APPENDIX R – OREGON RENEWABLE PORTFOLIO STANDARD 2025 RENEWABLE PLAN

## INTRODUCTION

In accordance with Oregon Revised Statute (ORS) 469A.075, PacifiCorp, d/b/a Pacific Power (Company or PacifiCorp), respectfully submits its 2025 Renewable Plan to the Public Utility Commission of Oregon (the Commission) as part of the 2025 Integrated Resource Plan (IRP).

This 2025 Renewable Plan represents a continuation of the Company's previously submitted Renewable Portfolio Standard Implementation Plans (RPIPs). Oregon House Bill (HB) 3161, which went into effect on January 1, 2024, amended ORS 469A.075 to eliminate the requirement for a separate RPIP submission, and instead now requires a utility subject to the Renewable Portfolio Standards (RPS) to submit, as part of the IRP, a renewable plan demonstrating how it will comply with the RPS. In response to the passage of HB 3161, on December 28, 2023, the Commission issued Order No. 23-484.[1] The order repealed OAR 860-083-0400, which formerly established the process for submitting a standalone RPIP, and amended the definition of "Integrated resource plan" in OAR 860-083-0010(22) to be consistent with the statutory elimination of a separate, standalone, RPIP filing. In addition, the order directs commission staff to work with interested persons toward the resolution of issues resulting from the inclusion of renewable portfolio implementation plans as part of the IRP process in a collaborative, separate docket or process.

Although a separate docket has not been established to work toward resolution of outstanding implementation issues created by HB 3161, PacifiCorp and Commission Staff discussed the required content of this 2025 Renewable Plan and PacifiCorp's timing concerns with incremental cost calculations in the 2025 Renewable Plan with the IRP. On January 14, 2025, PacifiCorp filed a Petition for Partial Term Wavier of OAR 860-083-0100, Renewable Plan Incremental Costs Calculation, and Related Requirements.[2] And, on March 18, 2025, the Commission issued Order No. 25-108 approving the waiver.[3] The Commission's order directs PacifiCorp with respect to the 2025 Renewable Plan as follows:

- Partially waives the incremental cost rule, subparts OAR 860-083-0100(1)(a), (g), (h), (2)(b), (7), and (9)(d) as applied to any resource whose incremental cost has been previously determined in an RPIP;

- Allows the complete submission of the renewable plan, including the incremental cost calculations, within 90 days of filing the 2025 IRP; and

- Excludes the Low $CO_2$ and Medium Proxy Plant fuel cost scenario from the list of required fuel cost scenarios.

[1] https://apps.puc.state.or.us/orders/2023ords/23-484.pdf
[2] https://edocs.puc.state.or.us/efdocs/HAA/haa334228025.pdf
[3] https://apps.puc.state.or.us/orders/2025ords/25-108.pdf

In addition, Commission Staff's memorandum in support of PacifiCorp's petition for a partial waiver acknowledges that it has not yet formally addressed questions regarding the content, scope, and submission of renewable plans as recommended in Order No. 23-484, following the adoption of HB 3161.[4] PacifiCorp is encouraged by Commission Staff's commitment to address these issues "before the end of 2025 through either workshops or opening a docket." PacifiCorp looks forward to continuing to work with Commission Staff to address issues of renewable plan implementation.

Consistent with this direction from the Commission, PacifiCorp respectfully submits this 2025 Renewable Plan in two steps. This first portion of the 2025 Renewable Plan summarizes PacifiCorp's methodology for planning compliance with the RPS, summarizes the applicable statutes and rules, lists the annual targets for acquisition and use of qualifying electricity based on 2025 IRP forecasted retail sales, and lists the resources available to PacifiCorp to plan for compliance during the 2025-2029 planning period. PacifiCorp will submit the second part of the 2025 Renewable Plan within 90 days of the filing of this IRP and it will include the estimated cost of meeting the annual targets, based on the incremental cost calculations.

## SUMMARY

This 2025 Renewable Plan shows that PacifiCorp intends to meet Oregon Renewable Portfolio Standard (RPS) targets during compliance years 2025–2029 with a combination of bundled and unbundled renewable energy certificates (RECs) from existing Oregon-eligible renewable resources and resources under development that are anticipated to be Oregon RPS-eligible.

### 2025 Renewable Plan Methodology and Assumptions

Unless stated otherwise, PacifiCorp prepared this 2025 Renewable Plan consistent with information from PacifiCorp's 2023 Renewable Portfolio Implementation Plan (RPIP) and its 2025 Integrated Resource Plan (IRP), including load forecasts and projected resources. The Company's IRP process and its filed documentation are based on the best available information at the time the IRP was prepared. PacifiCorp's 2025 IRP Action Plan represents a road map for implementation of the preferred portfolio. Consistent with the 2025 IRP Action Plan and preferred portfolio, this 2025 Renewable Plan includes new utility-owned or contracted wind resources as well as new utility-owned or contracted solar resources in 2028 and 2029. Economic and regulatory environments are continually changing, and PacifiCorp may modify its plans as state and federal legislation and regulations evolve. Such changes may materially impact resource acquisitions and the timing of those acquisitions.

In this 2025 Renewable Plan, the Company incorporated the Community Solar Program subscription sales and deducted those from the Oregon retail sales for the purpose of calculating the RPS target, pursuant to OAR 860-088-0150 (1). The Company included renewable resources that have been acquired or are under contract and received Oregon Department of Energy (ODOE) certification to qualify as eligible for the Oregon RPS. In addition, the plan includes resources anticipated to receive certification as eligible for the Oregon RPS under ORS 469A.025. Finally, the plan also assumes that all qualifying resources will be recertified with ODOE to maintain eligibility through the 2025–2029 planning period. The existing qualifying resources and resources

[4] https://apps.puc.state.or.us/orders/2025ords/25-108.pdf

under development will enable PacifiCorp to meet the 2025-2029 Oregon RPS targets. This 2025 Renewable Plan assumes that PacifiCorp will use its bank of bundled RECs and that the Company will not purchase additional unbundled RECs to meet RPS targets in the 2025-2029 reporting period.

PacifiCorp plans to comply with the Oregon RPS using both bundled and unbundled RECs. Furthermore, this 2025 Renewable Plan assumes that RECs with the oldest vintage dates will be used first for RPS compliance before RECs with a newer vintage date. PacifiCorp does not plan to use any bundled RECs issued between January 1 through March 31 of the year following the compliance year or alternative compliance payments.

## Applicable Requirements

This 2025 Renewable Plan is guided by requirements in statute, rule, and previous Commission orders, including:

ORS 469A.075(2), which states that a plan for meeting the requirements of the RPS must contain:

(a) Annual targets for acquisition and use of qualifying electricity; and
(b) The estimated cost of meeting the annual targets, including the cost of transmission, the cost of firming, shaping and integrating qualifying electricity, the cost of alternative compliance payments and the cost of acquiring renewable energy certificates.

OAR 860-083 establishes renewable portfolio standard rules, including OAR 860-083-0100, which directs regulated entities on how to calculate incremental costs of renewable resources compared to a proxy plant. This incremental cost calculation is used to show the estimated cost of meeting the annual targets, as required by ORS 469A.075(2)(b).

Finally, while there are no rules that proscribe the specific proxy plant scenarios, previous Commission orders have established the following scenarios applicable to this 2025 Renewable Plan:

- Medium carbon dioxide ($CO_2$) and low proxy plant fuel costs
- Medium $CO_2$ and medium proxy plant fuel costs
- Medium $CO_2$ and high proxy plant fuel costs
- High $CO_2$ and medium proxy plant fuel costs
- No $CO_2$ and medium proxy plant fuel costs
- Maximized use of unbundled RECs

The Commission established and amended the required scenarios in Commission Order Nos. 11-440, 14-267 and 25-108. A full explanation and description of these scenarios are included in Chapter 8.

Using the forecasts provided in the 2025 IRP's preferred portfolio and action plan, PacifiCorp will demonstrate compliance with the authorities listed above and show both annual targets for acquisition and use of qualifying electricity, and the estimated cost of meeting annual RPS targets during the 2025-2029 planning period, in the second part of the 2025 Renewable Plan, filed within 90 days of the 2025 IRP.

## ANNUAL TARGETS

The 2025 IRP prepares a forecast of the Oregon retail sales and is provided in Appendix A (Load Forecast). Table R.1 below provides the RPS compliance percentage target, the forecasted Oregon retail sales, the amount of energy associated with the Community Solar Program projects, and the estimated annual megawatt-hour (MWh) targets for each year in the 2025 Renewable Plan.

**Table R.1 – Oregon RPS Target Data**

| | 2025 | 2026 | 2027 | 2028 | 2029 |
|---|---|---|---|---|---|
| Applicable RPS % as a percentage of Electricity Sold | 27% | 27% | 27% | 27% | 27% |
| Oregon Retail Sales Forecast (MWh) | 14.316,773 | 14,420,803 | 14,401,692 | 14,397,746 | 14,342,388 |
| Community Solar Program (MWh) | 67,135 | 66,773 | 66,464 | 66,176 | 65,867 |
| Target retail sales is calculated by subtracting the MWh from the Community Solar Program from total retail sales. | 14,249,638 | 14,354,030 | 14,335,228 | 14,331,570 | 14,276,521 |
| Estimated Oregon RPS Target (MWh) | 3,847,402 | 3,875,588 | 3,870,512 | 3,869,524 | 3,854,661 |

## OREGON RPS ELIGIBLE RESOURCES

Generating facilities that have been certified by ODOE as eligible for the Oregon RPS program and resources that are under development and expected to be certified as eligible for the Oregon RPS program during the 2025-2029 planning period are listed in Table R.2. The generating facilities, either owned by PacifiCorp or under contract, are expected to provide RECs for compliance with the Oregon RPS during the 2025-2029 planning period. Table R.2 provides the facility name, the facility's energy source, the state where the facility is located, the status of the facility as either new or existing, and the when the facility became or is expected to become operational. A new facility is one whose incremental cost has not yet been calculated in a previous RPIP. An existing facility is one whose incremental cost has been calculated in a previous RPIP.

## Table R.2 – Oregon RPS Generating Facilities and Resources

| Energy Source | Generating Facility | State | Commercial Operation Year |
|---|---|---|---|
| **BIOGAS** | Hill Air Force Base PPA | UT | 2005 |
| **BIOMASS** | Roseburg Forest Products – Dillard PPA* | OR | 2019 |
| **GEOTHERMAL** | Blundell II | UT | 2007 |
| **WIND** | Anticline PPA* | WY | 2024 |
| | Boswell PPA * | WY | 2024 |
| | Campbell Hill-Three Buttes PPA | WY | 2009 |
| | Cedar Creek PPA* | ID | 2024 |
| | Cedar Springs Wind, LLC PPA | WY | 2020 |
| | Cedar Springs Wind III, LLC PPA | WY | 2020 |
| | Cedar Springs II | WY | 2020 |
| | Cedar Springs IV PPA | WY | 2025 |
| | Combine Hills PPA | OR | 2003 |
| | Dunlap I | WY | 2010 |
| | Ekola Flats Wind | WY | 2020 |
| | Foote Creek I | WY | 1999 |
| | Foote Creek III* | WY | 2024 |
| | Foote Creek IV* | WY | 2024 |
| | Glenrock | WY | 2008 |
| | Glenrock III | WY | 2009 |
| | Goodnoe Hills | WA | 2008 |
| | High Plains | WY | 2009 |
| | Latigo PPA | WY | 2016 |
| | Leaning Juniper I | OR | 2006 |
| | Marengo | WA | 2007 |
| | Marengo II | WA | 2008 |
| | Meadow Creek – Five Pine PPA* | ID | 2012 |
| | Meadow Creek – North Point PPA* | ID | 2012 |
| | McFadden Ridge | WY | 2009 |
| | Mountain Wind Power PPA | WY | 2008 |
| | Mountain Wind Power II PPA | WY | 2008 |
| | Pioneer Wind | WY | 2016 |
| | Rock Creek I | WY | 2025 |
| | Rock Creek II | WY | 2025 |
| | Rock River I* | WY | 2024 |
| | Seven Mile Hill I | WY | 2008 |
| | Seven Mile Hill II | WY | 2008 |
| | TB Flats Wind I-II | WY | 2021 |
| | Top of the World PPA | WY | 2010 |
| | Wolverine Creek PPA | ID | 2006 |
| | Proxy Wind | OR | Various |

| | | | |
|---|---|---|---|
| **HYDRO** | Ashton | ID | 1917 |
| | Big Fork | MT | 1929 |
| | Clearwater 1 | OR | 1953 |
| | Clearwater 2 | OR | 1953 |
| | Copco 1 | CA | 1918 |
| | Cutler | UT | 1927 |
| | Fish Creek | OR | 1952 |
| | Grace | ID | 1908 |
| | JC Boyle | OR | 1958 |
| | Lemolo 1 | OR | 1955 |
| | Lemolo 2 | OR | 1956 |
| | Oneida | ID | 1915 |
| | Pioneer | UT | 1897 |
| | Prospect 2 | OR | 1928 |
| | Prospect 3 | OR | 1932 |
| | Slide Creek | OR | 1951 |
| | Soda | ID | 1924 |
| | Soda Springs | OR | 1952 |
| | Toketee | OR | 1950 |
| | Yale | WA | 1953 |
| **SOLAR** | Black Cap PPA | OR | 2012 |
| | Oregon Solar Incentive Program - Central Oregon (CO 1) | OR | 2010 |
| | Oregon Solar Incentive Program - Central Oregon (CO 2) | OR | 2011 |
| | Oregon Solar Incentive Program - Central Oregon (CO 3) | OR | 2013 |
| | Oregon Solar Incentive Program - Central Oregon (CO 4) | OR | 2016 |
| | Oregon Solar Incentive Program - Columbia River (CR 1) | OR | 2011 |
| | Oregon Solar Incentive Program - Columbia River (CR 2) | OR | 2014 |
| | Oregon Solar Incentive Program - Eastern Oregon (EO 1) | OR | 2010 |
| | Oregon Solar Incentive Program - Eastern Oregon (EO 2) | OR | 2011 |
| | Oregon Solar Incentive Program - Portland Oregon (PO 1) | OR | 2010 |
| | Oregon Solar Incentive Program - Portland Oregon (PO 2) | OR | 2013 |
| | Oregon Solar Incentive Program - Portland Oregon (PO 3) | OR | 2016 |
| | Oregon Solar Incentive Program - Southern Oregon (SO 1) | OR | 2010 |
| | Oregon Solar Incentive Program - Southern Oregon (SO 2) | OR | 2011 |
| | Oregon Solar Incentive Program - Southern Oregon (SO 3) | OR | 2011 |
| | Oregon Solar Incentive Program - Southern Oregon (SO 4) | OR | 2012 |
| | Oregon Solar Incentive Program - Southern Oregon (SO 5) | OR | 2012 |
| | Oregon Solar Incentive Program - Southern Oregon (SO 6) | OR | 2013 |
| | Oregon Solar Incentive Program - Southern Oregon (SO 7) | OR | 2013 |
| | Oregon Solar Incentive Program - Southern Oregon (SO 8) | OR | 2013 |
| | Oregon Solar Incentive Program - Southern Oregon (SO 9) | OR | 2013 |
| | Oregon Solar Incentive Program - Southern Oregon (SO 10) | OR | 2014 |

| | | | |
|---|---|---|---|
| | Oregon Solar Incentive Program - Southern Oregon (SO 11) | OR | 2014 |
| | Oregon Solar Incentive Program - Southern Oregon (SO 12) | OR | 2015 |
| | Oregon Solar Incentive Program - Southern Oregon (SO 13) | OR | 2016 |
| | Oregon Solar Incentive Program - Willamette Valley (WV 1) | OR | 2010 |
| | Oregon Solar Incentive Program - Willamette Valley (WV 2) | OR | 2011 |
| | Oregon Solar Incentive Program - Willamette Valley (WV 3) | OR | 2012 |
| | Oregon Solar Incentive Program - Willamette Valley (WV 4) | OR | 2013 |
| | Oregon Solar Incentive Program - Willamette Valley (WV 5) | OR | 2013 |
| | Oregon Solar Incentive Program - Willamette Valley (WV 6) | OR | 2013 |
| | Oregon Solar Incentive Program - Willamette Valley (WV 7) | OR | 2014 |
| | Oregon Solar Incentive Program - Willamette Valley (WV 8) | OR | 2015 |
| | Oregon Solar Incentive Program - Willamette Valley (WV 9) | OR | 2015 |
| | Oregon Solar Incentive Program - Willamette Valley (WV 10) | OR | 2017 |
| | Lakeview | OR | 2012 |
| | Lakeview II | OR | 2013 |
| | Oregon Solar Incentive Program - (Joseph Community) Wallowa County | OR | 2011 |
| | Powell Butte | OR | 2014 |
| | Crook County Solar | OR | 2014 |
| | Confederated Tribes of Warm Springs (CTWS) | OR | 2014 |
| | Solwatt | OR | 2012 |
| | Solwatt II | OR | 2014 |
| | Bourdet | OR | 2014 |
| | Bourdet II | OR | 2016 |
| | Keeton 1 | OR | 2016 |
| | Keeton 2 | OR | 2016 |
| | Hammerich 1 | OR | 2016 |
| | Hammerich 2 | OR | 2016 |
| | Pavant Solar II LLC PPA | UT | 2016 |
| | Pavant Solar, LLC PPA | UT | 2015 |
| | Enterprise Solar, LLC PPA | UT | 2016 |
| | Adams Solar Center, LLC PPA | OR | 2018 |
| | Bear Creek Solar Center, LLC PPA | OR | 2018 |
| | Bly Solar Center, LLC PPA | OR | 2018 |
| | Elbe Solar Center, LLC PPA | OR | 2018 |
| | Chiloquin Solar PPA* | OR | 2018 |
| | Granite Mountain – East PPA* | UT | 2016 |
| | Granite Mountain – West PPA* | UT | 2016 |
| | Iron Springs Solar PPA* | UT | 2016 |
| | Klamath Falls Solar 2 (Ewauna Solar) PPA* | OR | 2017 |
| | Norwest Energy 9 (Pendleton) PPA* | OR | 2018 |
| | Oregon Solar Land Holdings (OLSH) PPA * | OR | 2017 |
| | OR Solar 2, LLC (Agate Bay Solar) PPA * | OR | 2020 |

| | | | |
|---|---|---|---|
| | OR Solar 3, LLC (Turkey Hill Solar) PPA * | OR | 2017 |
| | OR Solar 5, LLC (Merrill Solar) PPA * | OR | 2018 |
| | OR Solar 6, LLC (Lakeview Solar) PPA * | OR | 2017 |
| | OR Solar 8, LLC (Dairy Solar) PPA * | OR | 2018 |
| | Orchard Wind Farm 1, LLC PPA* | OR | 2020 |
| | Orchard Wind Farm 2, LLC PPA* | OR | 2020 |
| | Orchard Wind Farm 3, LLC PPA* | OR | 2020 |
| | Orchard Wind Farm 4, LLC PPA* | OR | 2020 |
| | Sage Solar 1 PPA | WY | 2019 |
| | Sage Solar 2 PPA | WY | 2019 |
| | Sage Solar 3 PPA | WY | 2019 |
| | Skysol Solar PPA* | OR | 2023 |
| | Sweetwater Solar PPA | WY | 2018 |
| | Tumbleweed Solar PPA* | OR | 2017 |
| | Woodline Solar PPA* | OR | 2017 |
| | Proxy Solar | OR | Various |

*Indicates resource has not been included in previous Oregon Renewable Portfolio Standard Implementation Plans. In some cases, PacifiCorp may only receive RECs for a portion of the term of the contract.

# INCREMENTAL COSTS

Pursuant to Order No. 25-108, within 90 days of the filing of PacifiCorp's 2025 IRP, the Company will provide the estimated cost of meeting the annual targets, including the cost of transmission, the cost of firming, shaping and integrating qualifying electricity, the cost of alternative compliance payments and the cost of acquiring renewable energy certificates.

# APPENDIX Z – ACRONYMS

AB = Assembly Bill

AC = alternating current

ACE = Affordable Clean Energy Rule

ACE = Area Control Error

AEG = applied energy group

AFSL = average feet (above) sea level

AFUDC = allowance for funds used during construction

AGC = Automatic Generation Control

AH = Ampere hour

A/m = Amperes per Meter

AMI = Advance Metering Infrastructure

AMR = Automated Meter Reading

ARO = asset retirement obligation

ATC = Available Transmission Capacity (Available Transfer Capacity?)

AVR = Automatic Voltage Regulator

AWEA = American Wind Energy Association

BA – Balancing Authority

BAA = Balancing Authority Area

BART = Best Available Retrofit Technology

BCF/D = billion cubic feet per day

BES = Bulk Electric System

BLM = Bureau of Land Management

BMcD = Burns and McDonnell

BPA = Bonneville Power Administration

BSER = best system of emission reduction

Btu = British thermal unit

CAES = compressed air energy storage

CAGR = compounded annual average growth rate

CAIDI = Customer Average Interruption Duration Index

CAISO = California Independent System Operator

CAP = Community Action Program

CARB = California Air Resources Board

CARI = Control Area Reliability Issues

CCCT = Combined Cycle Combustion Turbine

CCGT = Combined Cycle Gas Turbine

CCR = coal combustion residual

CCS = carbon capture and sequestration / Utah Committee of Consumer Services

CEC = California Energy Commission

CETA = Clean Energy Transformation Act

CF = capacity factor

CFL = Compact Fluorescent Light Bulb

CIPS = Critical Infrastructure Protection Standards

CIS = Corporate Information Security

CO = carbon monoxide

$CO_2$ = carbon dioxide

Cogen = Cogeneration

COMPASS = Coordinated Outage Management Planning and Scheduling System?

CPA = Conservation Potential Assessment

CPU = Clark Public Utilities / cost per unit

CPUC = California Public Utilities Commission

CREA = Columbia Rural Electric Association

CSP = concentrated solar power

CTG = Combustion Turbine Generator

CUB = (Oregon) Citizen's Utility Board

DC = direct current

DF = duct firing

DG = Distributed Generation

DOE = Department of Energy

DPU = Utah Division of Public Utilities / Distribution Protection Unit (relay)

DR = Demand Response

DRA = Division of Ratepayer Advocates

DSM = demand-side management

EBIT = Earnings before Interest and Taxes

EDAM = extended day-ahead market

EE = Energy Efficiency

EEI = Edison Electric Institute

EIA = Energy Information Administration

EIM = Energy Imbalance Market

ELCC = Effective Load Carrying Capacity

EPA = Environmental Protection Agency

EPC = engineering, procurement, and construction

EPM = Energy Portfolio Management System

ERC = emission rate credit

ETO = Energy Trust of Oregon

EUBA = Electric Utility Benchmarking Association

EUI = Energy Utilization Index

EUL = effective useful life

EV = Electric Vehicle

FCC = Federal Communications Commission

FCRPS = Federal Columbia River Power System

FERC = Federal Energy Regulatory Commission

FIP = federal implementation plan

FIT = Feed-In Tariff

FLPMA = Federal Land Policy Management Ace

FOTs = Front Office Transactions

FRAC = Flexible Resource Adequacy Capacity

GAAP = Generally Accepted Accounting Principles

GBP = Great Britain Pound

GE = General Electric

GFCI = Ground Fault Circuit Interrupter

GHG = Greenhouse Gas

GIC = Generation Interconnection Contract

GIS = Geographic Information System

GPS = Global Positioning System

GRC = General Rate Case

GRID = Generation and Regulation Decision Model (used for net power cost pricing calc and QF avoided cost calc)

GT = Gas Turbine

GW = Gigawatt

GWh = gigawatt-hours (gigawatt)

H = Hour

HB = House Bill

HCC = Hydro Control Center

HRSG = Heat Recovery Steam Generator

HVAC = heating, ventilation, and air conditioning

Hz = Hertz

IBEW = International Brotherhood of Electrical Workers

IC = internal combustion

ICE = Intercontinental Exchange

IECC = International Energy Conservation Code

IEEE = Institute of Electrical and Electronic Engineers

IGCC = integrated gasification combined cycle

IHS = Information Handling Services

ILR = Inverter Loading Ratio

IOU = Investor Owned Utility

IPC = Idaho Power Company

IPP = Independent Power Producer

IPOC = Idaho Power Company

IPUC = Idaho Public Utility Commission

IRA = Inflation Reduction Act

IRP = Integrated Resource Plan

IS = Information Systems

ISO = Independent System Operator

IT = Information Technology

ITC = Investment Tax Credit

K = kilo (thousand)

Kv = kiloVolt

kW = kilowatt

kWh = kilowatt-hour

kW-yr = Kilowatt-Year

kV = kilovolt

kVa = kilovolt-ampere

kVAr = kilovolt-ampere-reactive

kVArh = kilovolt-ampere-reactive-hour

Lb = Pound

LCOE = Levelized Cost of Energy

LED = light emitting diode

Li-Ion = lithium-ion battery

Lm = lumens

LNG = Liquefied Natural Gas

LOLH = loss of load hour

LOLP = loss of load probability

LRA = Local Regulatory Authority

LSE = load serving entities

MATS = Mercury and Air Toxics Standards

MMBpd = Million barrels of oil per day

MMBtu = Million British thermal units

MSP = Multi-State Process

MVA = megavolt-ampere

MVAr = megavolt-ampere-reactive

MVA LTC = megavolt-ampere, load tap changing

MW = Megawatt

MWh = megawatt hour

$MWh = dollars per megawatt hour

NAAQS = National Ambient Air Quality Standards

NAPEE = National Action Plan for Energy-Efficiency

NCM = nickel cobalt manganese (sub-chemistry of Li-Ion)

NEEA = Northwest Energy Efficiency Alliance

NEEP = Northeast Energy Efficiency Partnerships

NEMA = National Electrical Manufacturer's Association

NEMS = National Energy Modeling System

NERC = North American Electric Reliability Corporation

$NH_3$ = Ammonia

NOAAF = National Oceanic and Atmospheric Administration Fisheries

NRC = Nuclear Regulatory Commission

NREL = National Renewable Energy Laboratory

NOx = Nitrogen Oxides

NPV = net present value

NQC = Net Qualifying Capacity

NSPS = new source performance standards

NTTG = Northern Tier Transmission Group

NWEC = NW Energy Coalition

NWPCC = Northwest Power and Conservation Council

O&M = operations and maintenance

OAR = Oregon Administrative Rules

OASIS = Open Access Same Time Information System

OATT = Open Access Transmission Tariff

ODOE = Oregon Department of Energy

ODOT = Oregon Department of Transportation

OE = Owner's Engineer

OEM = Original Equipment Manufacturer

OFPC = Official Forward Price

OMS = Outage Management System

OPUC = Oregon Public Utility Commission

ORS = Oregon Revised Statutes

OTR = Ozone Transport Rule

PAC = PacifiCorp

PACE = PacifiCorp East?

PaR = Planning and Risk Model

PC = pulverized coal

PCB = Polychlorinated Biphenyls

PC CCS = pulverized coal equipped with carbon capture and sequestration

PDDRR = Partial displacement differential revenue requirement methodology (OR QF)

PG&E = Pacific Gas & Electric

PGE = Portland General Electric

PHES = pumped hydro energy storage

PJM = no definition

PM = particulate matter

$PM_{2.5}$ = Particulate Matter 2.5 microns and larger

$PM_{10}$ = Particulate Matter 10 microns and larger

PNUCC = Pacific Northwest Utility Coordinating Council

POU = Publicly Owned Utility

PP = Pacific Power

PPA = Power Purchase Agreement

Ppb = parts per billion

PP&L = Pacific Power & Light Co.

ppmvd@15%02 = parts per million, dry-volumetric basis, corrected to 15% Oxygen ($O_2$)

PRM = Planning Reserve Margin

PSC = Public Service Commission

PSE = Purchasing-Selling Entity

Psia = Pounds per Square Inch-Absolute

PTC = Production tax credit

PTO = Participating Transmission Owner

PTP = point to point

PUC = Public Utility Commission

PURPA = Public Utility Regulatory Policies Act

PV = photovoltaic

PVRR(d) = present value revenue requirement (delta)

PWC = PricewaterhouseCoopers

QC = Qualifying Capacity

RA = Resource Adequacy

RCRA = Resource Conservation and Recovery Act

RCW = Revised Code of Washington

REA = Rural Electrical Administration / Rural Electrification Administration

REC = renewable energy credit (certificate)

RFI = request for information

RFM = Rate Forecasting Model

RFP = Request for Proposal

RH = Relative humidity

RICE = Reciprocating Internal Combustion Engine

RMP = Rocky Mountain Power

RPS = Renewable Portfolio Standard

RTO = Regional Transmission Organization

RTF = Regional Technical Forum

RTP = real-time pricing

RVOS = Resource Value of Solar

SAIDI = System Average Interruption Duration Index

SAIFI = System Average Interruption Frequency Index

SB = Senate Bill

SCCT = Simple Combined Cycle Turbine

SCPC = Super-critical pulverized coal

SCPPA = Southern California Public Power Authority

SCR = selective catalytic reduction system

SEC = Securities and Exchange Commission

SEEM = Simple Energy Enthalpy Model

SEPA = Solar Electric Power Association

SIP = state implementation plan

SF = Senate File

SF6 = Sulfur Hexafluoride

SNCR = selective non-catalytic reduction

SO = System Optimizer

$SO_2$ = Sulfur Dioxide

$SO_x$ = Sulfur Oxide

SRSG = Southwest reserve sharing group

SSR = small-scale renewable (note SSR is not used for 'supply-side resource')

STEP = Sustainable Transportation and Energy Plan

STG = Steam turbine generator

SWEEP = Southwest Energy Efficiency Project

T&D = Transmission & Distribution

th = Therm

TPL = transmission planning assessment

UAE = Utah Association of Energy Consumers

UDOT = Utah Department of Transportation

UMPA = Utah Municipal Power Agency

UNIDO = United Nations Industrial Development Organization

UP&L = Utah Power & Light Co.

UPC = Use per Residential Customer

UCE = Utah Clean Energy

UCT = Utility Cost Test

VERs = Variable Energy Resources

V = volt

VA = Volt-ampere

VDC = Volts Direct Current

VOC = volatile organic compounds

W = Watts

WAC = Washington Administrative Code

WACC = weighted average cost of capital

WAPA = Western Area Power Administration

WCA = West Control Area

WECC = Western Electricity Coordinating Council

Wh = Watt-hour

WIEC = Wyoming Industrial Energy Council

WPSC = Wyoming Public Service Commission

WRA = Western Resource Advocates

WRAP = Western Resource Adequacy Program

WREGIS = Western Renewable Generation Information System

WSEC = Washington State Energy Code 2015

WSPP = Western Systems Power Pool

WTG = wind turbine generator

WUTC = Washington Utilities and Transmission Commission