2025
Integrated Resource Plan (Draft)

Volume II - December 31, 2024

PACIFICORP

This 2025 Draft Integrated Resource Plan is based upon the best available information at the time of preparation. The 2025 Integrated Resource Plan is anticipated to be distributed March 31, 2025.

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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 compound annual load growth rate for the 10-year period (2025 through 2034) is 2.44 percent. Relative to the load forecast prepared for the 2023 IRP, PacifiCorp's 2034 forecast load requirement decreased in Oregon, California, Wyoming and Idaho, resulting in PacifiCorp system load requirement to decline 3.01 percent in 2034. Figure A.1 provides a comparison of the 2025 IRP and the 2023 IRP load forecasts.

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

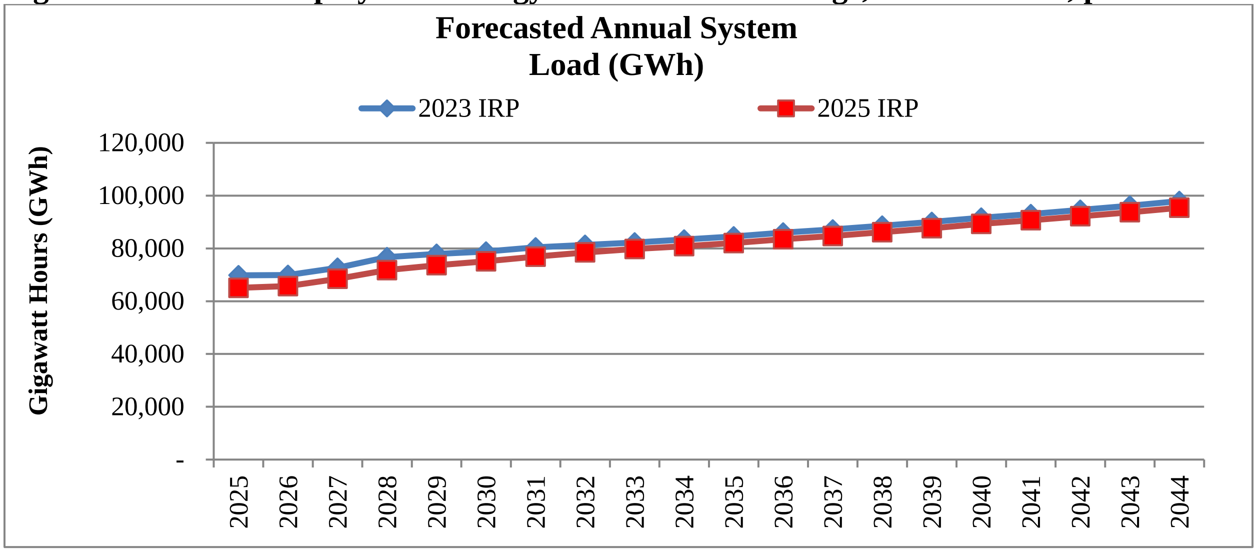


Table A.1 and Table A.2 show the annual load and coincident peak load forecast when not reducing load projections to account for new energy efficiency measures.[1] Table A.3 and Table A.4 show the forecast changes relative to the 2023 IRP load forecast for loads and coincident system peak, respectively.

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

Year	Total	OR	WA	CA	UT	WY	ID
2025	65,060,422	16,427,112	4,545,410	844,170	29,729,280	9,662,750	3,851,700
2026	65,709,687	16,686,547	4,573,810	844,790	30,092,110	9,640,700	3,871,730
2027	68,479,409	16,981,229	4,761,850	844,380	32,331,920	9,666,940	3,893,090
2028	71,791,117	17,211,827	4,957,640	845,780	35,172,110	9,684,200	3,919,560
2029	73,628,022	17,382,202	4,967,740	842,310	36,817,630	9,686,200	3,931,940
2030	75,117,094	17,597,704	4,993,880	841,360	38,053,630	9,681,100	3,949,420
2031	76,867,685	17,819,165	5,018,660	840,620	39,526,380	9,696,570	3,966,290
2032	78,480,937	18,085,127	5,055,940	842,410	40,802,960	9,704,760	3,989,740
2033	79,769,335	18,298,195	5,071,770	839,820	41,856,710	9,700,290	4,002,550
2034	80,843,645	18,574,275	5,100,920	839,770	42,614,010	9,691,460	4,023,210
Compound Annual Growth Rate							
2025-34	**2.44%**	**1.37%**	**1.29%**	**-0.06%**	**4.08%**	**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	11,374	2,758	830	146	5,647	1,233	760
2026	11,410	2,779	841	147	5,675	1,211	756
2027	11,708	2,808	880	147	5,909	1,211	753
2028	12,085	2,825	886	148	6,275	1,213	739
2029	12,303	2,848	891	148	6,462	1,214	739
2030	12,501	2,879	895	148	6,622	1,218	740
2031	12,824	2,959	898	148	6,830	1,220	769
2032	12,961	2,931	901	148	6,998	1,218	765
2033	13,156	2,978	904	148	7,157	1,218	751
2034	13,358	3,073	941	152	7,210	1,210	773
Compound Annual Growth Rate							
2025-34	**1.80%**	**1.21%**	**1.40%**	**0.44%**	**2.75%**	**-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	(4,744,638)	(3,303,208)	(155,350)	(11,050)	(631,940)	(412,110)	(230,980)
2026	(4,228,733)	(3,771,103)	(147,950)	(8,180)	404,630	(472,540)	(233,590)
2027	(4,170,361)	(4,780,061)	5,020	(8,800)	1,297,500	(450,000)	(234,020)
2028	(4,890,003)	(6,234,133)	146,440	(10,700)	1,988,370	(544,910)	(235,070)
2029	(4,291,258)	(6,570,578)	126,430	(12,850)	2,956,270	(553,770)	(236,760)
2030	(3,694,746)	(6,468,356)	108,530	(14,430)	3,569,730	(651,450)	(238,770)
2031	(3,513,005)	(7,002,525)	87,960	(15,980)	4,326,490	(667,550)	(241,400)
2032	(2,840,843)	(7,075,753)	65,540	(17,550)	5,202,610	(771,970)	(243,720)
2033	(2,452,895)	(7,121,585)	45,520	(18,880)	5,694,760	(807,980)	(244,730)
2034	(2,507,895)	(7,167,315)	23,940	(20,350)	5,768,680	(868,020)	(244,830)

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

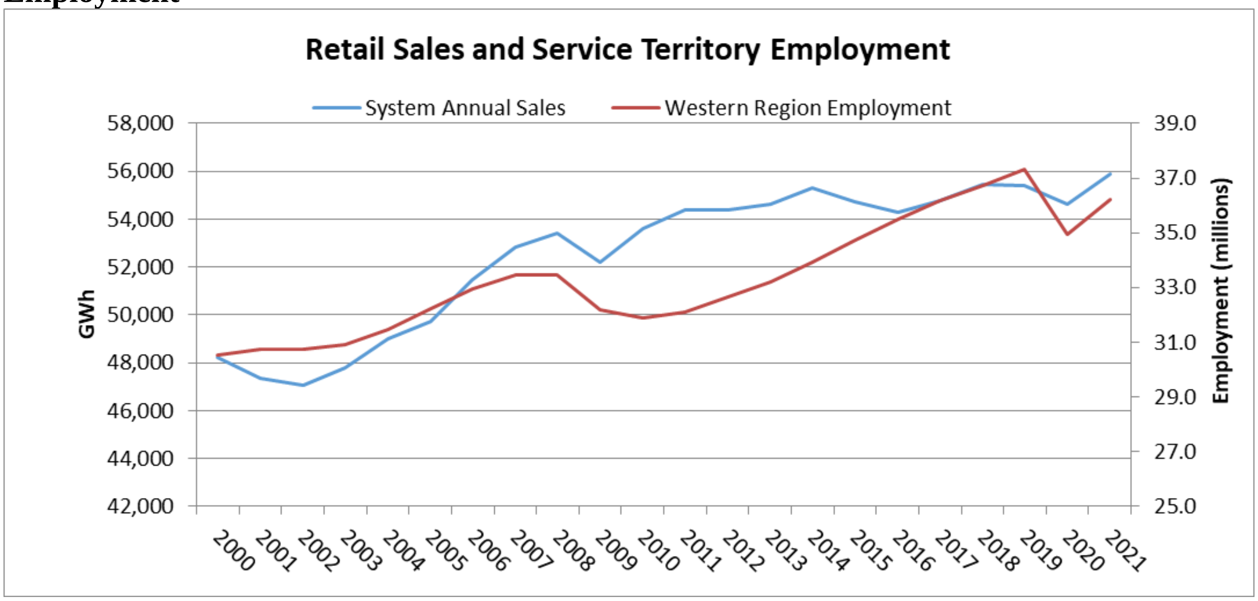
Year	Total	OR	WA	CA	UT	WY	ID
2025	(373)	(253)	(26)	(1)	19	(68)	(43)
2026	(349)	(275)	(30)	(1)	103	(94)	(52)
2027	(343)	(380)	(7)	(2)	202	(95)	(60)
2028	(400)	(499)	(19)	(4)	282	(105)	(55)
2029	(380)	(639)	(36)	(9)	439	(77)	(59)
2030	(314)	(628)	(51)	(10)	521	(83)	(63)
2031	(298)	(672)	(68)	(12)	616	(91)	(72)
2032	(248)	(701)	(84)	(13)	729	(97)	(82)
2033	(191)	(693)	(102)	(14)	800	(104)	(79)
2034	(155)	(638)	(85)	(11)	762	(121)	(62)

Load Forecast Assumptions

Regional Economy by Jurisdiction

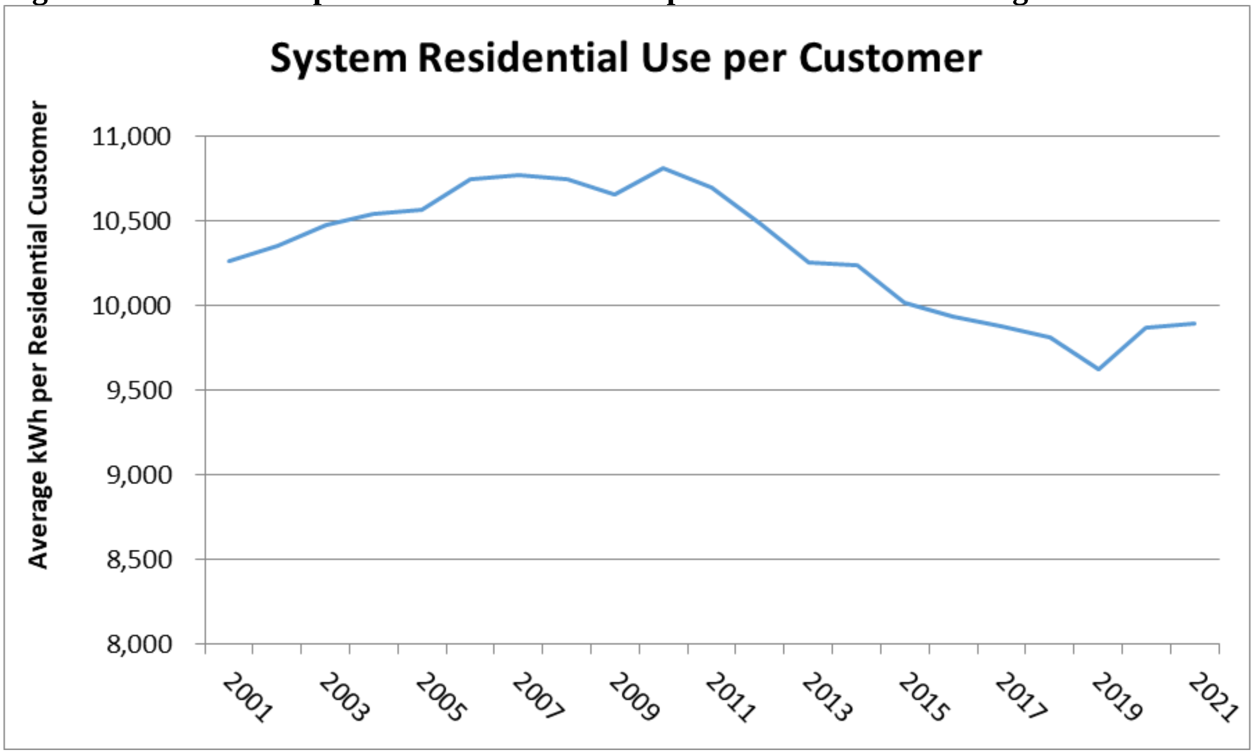
The PacifiCorp electric service territory is comprised of six states and within these states the Company serves customers in a total of 90 counties. The level of retail sales for each state and county is correlated with economic conditions and population statistics in each state. PacifiCorp uses both 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, 2000 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 2000 through 2021 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 2001 through 2021



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

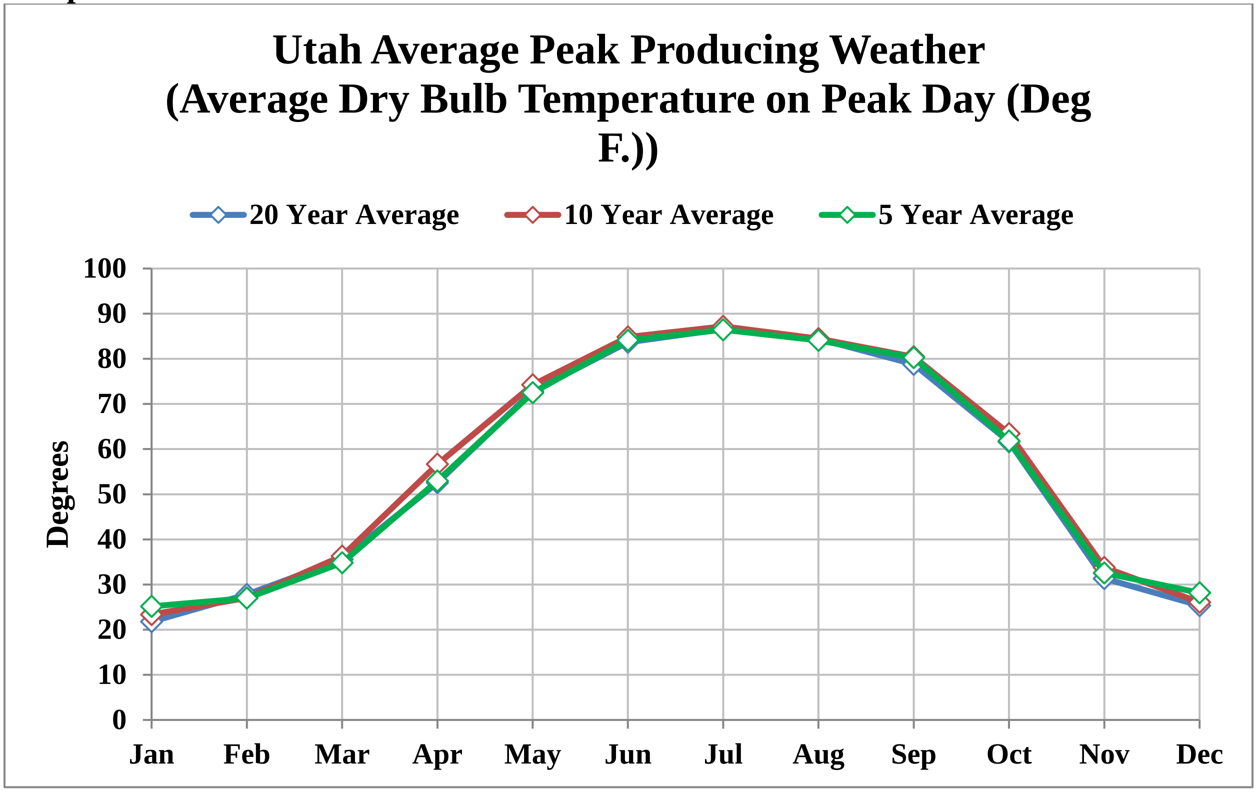
*Lower bound of temperature projections based on RCP 4.5, while upper bound based on RCP 8.5

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 data center forecasts within the respective jurisdictions.

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

Actual Load Data

Note – Certain load forecast tables indicated in the following pages are not included in the 2025 Draft IRP, and are anticipated to be provided in the March 31, 2025 final filing.

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 2000 through 2021

To be included within final 2025 IRP submittal.

Table A.7 – Non-Coincident Jurisdictional Peak 2000 through 2023

To be included within final 2025 IRP submittal.

Table A.8 – Jurisdictional Contribution to Coincident Peak 2000 through 2023

To be included within final 2025 IRP submittal.

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 modeled 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 similar to 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.

The majority of 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 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

[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.

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.

To be included within final 2025 IRP submittal.

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

To be included within final 2025 IRP submittal.

State Summaries

Oregon

Table A.10 summarizes Oregon state forecasted retail sales growth by customer class.

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

To be included within final 2025 IRP submittal.

Washington

Table A.11 summarizes Washington state forecasted retail sales growth by customer class.

Table A.11 – Forecasted Retail Sales Growth in Washington, post-DSM

To be included within final 2025 IRP submittal.

California

Table A.12 summarizes California state forecasted sales growth by customer class.

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

To be included within final 2025 IRP submittal.

Utah

Table A.13 summarizes Utah state forecasted sales growth by customer class.

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

To be included within final 2025 IRP submittal.

Idaho

Table A.14 summarizes Idaho state forecasted sales growth by customer class.

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

To be included within final 2025 IRP submittal.

WyomingError! Reference source not found. summarizes Wyoming state forecasted sales g rowth by customer class.

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

To be included within final 2025 IRP submittal.

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 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

To be included within final 2025 IRP submittal.

APPENDIX B - REGULATORY COMPLIANCE

Introduction

This appendix describes general state requirements for PacifiCorp's 2025 Integrated Resource Plan (IRP). Line-item details for each states' compliance, which is dependent on information that is not included in this draft, will be provided in the March 31, 2025 filing.

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 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 Volume I, Chapter 2 (Introduction), as well as Volume II, Appendix C (Public).

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 Volume I, 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 Volume I, 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 draft portfolio analysis and the results and conclusions drawn from the analysis are described in Volume I, Chapter 9.

Consistent with the IRP standards and guidelines of Oregon, Utah, and Washington, this draft includes an Action Plan in Volume I, Chapter 10 (Action Plan). 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 instructed 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). D.18-02-018 also instructed PacifiCorp to provide 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[1] and D.22-12-030 issued on December 19, 2022, approving the company's 2021 IRP Supplement (2022 Off-Year Supplement to its 2021 IRP).

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.

[1] 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).*

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.

On January 18, 2023, PacifiCorp filed its 2021 IRP Supplement (2022 Off-Year Supplement to its 2021 IRP) in Docket R.18-07-003 in compliance with D.08-05-029 and D.22-12-030.

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.

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 2023, 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). 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), and flexible resource capacity (Order No. 12-013). Consistent with the earlier guidelines (Order 89-507[2]), 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 provides detail on how this plan addresses each of the requirements.[3]

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

[3] 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.

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 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 rule requiring a two-year progress report of the previously filed plan, which was the Company's 2021 IRP (Washington Administrative Code 480-100-625) (effective, December 2020).

In its report, the rule requires PacifiCorp to include an update of its load forecast; demand-side resource assessment, including new conservation potential assessment; resource costs; and the portfolio analysis and preferred portfolio. The report must also include other updates that are necessary due to changing state or federal requirements, or significant changes to economic or market forces; and an update for any elements found in the Company's current Clean Energy Implementation Plan (CEIP). Please refer to Appendix O (Washington Two-year Progress Report Additional Elements) for additional detail regarding updates to elements of the Company's CEIP.

Wyoming

Wyoming Public Service Commission issued new rules that replaced the previous set of rules on March 21, 2016. Chapter 3, Section 33 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.*

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

Topic	Oregon	Utah	Washington	Idaho	Wyoming
Source	Order No. 07-002, *Investigation Into Integrated Resource Planning*, January 8, 2007, as amended by Order No. 07-047. Guideline 2c: The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission. Order No. 08-339, *Investigation into the Treatment of CO2 Risk in the Integrated Resource Planning Process*, June 30, 2008 Order No. 09-041, New Rule OAR 860-027-0400, implementing Guideline 3, "Plan Filing, Review, and Updates". Order No. 12-013, "Investigation of Matters related to Electric Vehicle Charging", January 19, 2012	Docket 90-2035-01 *Standards and Guidelines for Integrated Resource Planning* June 18, 1992.	WAC 480-100-251 Least cost planning, May 19, 1987, and as amended from WAC 480-100-238 *Least Cost Planning Rulemaking*, January 9, 2006 (Docket # UE-030311). WAC 480-100-625(3) Draft IRP. Commission General Order R-601 further adopted IRP rules compliant with CETA.	Order 22299 *Electric Utility Conservation Standards and Practices* January 1989.	Wyoming Electric, Gas and Water Utilities, Chapter 3, Section 33, March 21, 2016.

Filing Requirements	Least-cost plans must be filed with the Oregon PUC.	An IRP is to be submitted to commission.	Submit a least cost plan to the WUTC. 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.
Frequency	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. 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.
Commission Response	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.	The plan will be considered, with other available information, when evaluating the performance of the utility in rate proceedings. WUTC sends a letter discussing the report, making suggestions and requirements and acknowledges the report.	Report does not constitute pre-approval of proposed resource acquisitions. 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.

Filing Requirements	Least-cost plans must be filed with the Oregon PUC.	An IRP is to be submitted to commission.	Submit a least cost plan to the WUTC. 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.
	Note, however, that Rate Plan legislation allows pre-approval of near-term resource investments.				

Process	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. 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. Involvement by the public in development of the plan is required. 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. The work plan is to lay out the contents of the IRP, resource assessment method, and timing and extent of public participation. Draft IRP. No later than four months prior to the due date of the final IRP, the utility must file its draft IRP with the commission. At minimum, the draft IRP	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. The Public Service Commission of Wyoming, in its Letter Order on PacifiCorp’s 2008 IRP (Docket No. 2000-346-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.

			must include the preferred portfolio, CEAP, and supporting analysis, and to the extent practicable all scenarios, sensitivities, appendices, and attachments. (a) The commission will hear public comment on the draft IRP at an open meeting scheduled after the utility files its draft IRP. The commission will accept public comments electronically and in any other available formats, as outlined in the commission's notice for the open public meeting and opportunity to comment. (b) The utility must file with the commission completed presentation materials concerning the draft IRP at least five business days prior to the open meeting.		

Focus	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, with short-term (two-year) action plan. The plan describes mix of resources sufficient to meet current and future loads at "lowest reasonable" cost to utility and ratepayers. 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.	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.

			As part of the IRP, utilities must develop a ten-year clean energy action plan for implementing RCW 19.405.030 through 19.405.050.		
Elements	Basic elements include: • All resources evaluated on a consistent and comparable basis. • Risk and uncertainty must be considered. • The primary goal must be least cost, consistent with the long-run public interest. • The plan must be consistent with Oregon and federal energy policy. • External costs must be considered, and quantified where possible. OPUC specifies environmental adders (Order No. 93-695, Docket UM 424). • Multi-state utilities should plan their generation and transmission systems on an integrated-system basis. • Construction of resource portfolios over the range of	IRP will include: • Range of forecasts of future load growth • Evaluation of all present and future resources, including demand side, supply side and market, on a consistent and comparable basis. • Analysis of the role of competitive bidding • A plan for adapting to different paths as the future unfolds. • A cost effectiveness methodology. • An evaluation of the financial, competitive, reliability and operational risks associated with resource options, and how the action plan addresses these risks. • Definition of how risks are allocated between ratepayers and shareholders	The plan shall include: • A range of forecasts of future demand using methods that examine the effect of economic forces on the consumption of electricity and that address changes in the number, type, and efficiency of electrical end-uses. • An assessment of commercially available conservation, including load management, as well as an assessment of currently employed and new policies and programs needed to obtain the conservation improvements. • Assessment of a wide range of conventional and commercially available nonconventional generating technologies • An assessment of transmission system capability and reliability.	Discuss analyses considered including: • Load forecast uncertainties; • Known or potential changes to existing resources; • Equal consideration of demand and supply side resource options; • Contingencies for upgrading, optioning, and acquiring resources at optimum times. • Report on existing resource stack, load forecast and additional resource menu.	Proposed Commission Staff guidelines issued July 2016 cover: • Sufficiency of the public comment process • Utility strategic goals, resource planning goals and preferred resource portfolio • Resource need over the near-term and long-term planning horizons • Types of resources considered • Changes in expected resource acquisitions and load growth from the previous IRP • Environmental impacts considered • Market purchase evaluation • Reserve margin analysis • Demand-side management and conservation options

	identified risks and uncertainties. • Portfolio analysis shall include fuel transportation and transmission requirements. • Plan includes conservation potential study, demand response resources, environmental costs, and distributed generation technologies. • Avoided cost filing required within 30 days of acknowledgment.		• A comparative evaluation of energy supply resources (including transmission and distribution) and improvements in conservation using "lowest reasonable cost" criteria. • An assessment and determination of resource adequacy metrics. • An assessment of energy and nonenergy benefits and reductions of burdens to vulnerable populations and highly impacted communities; long-term and short-term public health and environmental benefits, costs, and risks; and energy security risk • Integration of the demand forecasts and resource evaluations into a long-range (at least 10 years) plan. • All plans shall also include a progress report that relates the new plan to the previously filed plan. • Must develop a ten-year clean energy action plan for implementing RCW 19.405.030 through 19.405.050.		

			• The IRP must include a summary of substantive changes to modeling methodologies or inputs that result in changes to the utility's resource need, as compared to the utility's previous IRP. • The IRP must include an analysis and summary of the avoided cost estimate for energy, capacity, transmission, distribution, and greenhouse gas emissions costs. The utility must list nonenergy costs and benefits addressed in the IRP and should specify if they accrue to the utility, customers, participants, vulnerable populations, highly impacted communities, or the general public. • The utility must provide a summary of public comments received during the development of its IRP and the utility's responses, including whether issues raised in the comments were addressed and incorporated into the final IRP as well as		

			documentation of the reasons for rejecting any public input.		

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 25-26, 2024

- 2025 IRP Progress Report
- Supply-side Resources
- Data Center Load Studies
- State and Federal Updates
- Stakeholder Feedback Summary

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

Two additional public input meetings are scheduled in the 2025 IRP public input meeting series to be held subsequent to the December 31, 2024, distribution of the 2025 Draft IRP:

- January 22-23, 2025
- February 26-27, 2025

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	√	√	√	√	√	√

Error! Not a valid bookmark self-reference. 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 by state and year in the 2025 IRP preferred portfolio.[5]

[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] Following DSM resource selection methodologies described in Chapter 7 of the IRP.

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

Resource	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
DR Summer - CA	0	0	0	3	4	5	5	5	5	5	5
DR Winter - CA	0	0	0	0	0	0	0	0	0	0	0
DR Summer - ID	0	0	0	13	14	15	15	15	15	26	30
DR Winter - ID	0	0	0	0	0	0	0	0	0	0	0
DR Summer - OR	2	7	7	37	37	37	37	37	37	37	37
DR Winter - OR	0	19	26	35	40	101	108	111	114	117	118
DR Summer - UT	2	2	2	57	73	89	89	117	117	148	161
DR Winter - UT	0	0	0	0	0	0	0	0	0	0	0
DR Summer - WA	2	6	10	18	19	19	25	26	26	27	27
DR Winter - WA	0	11	11	11	11	11	11	11	11	11	11
DR Summer - WY	12	12	12	39	47	51	51	52	52	53	57
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	6	6	6	6	6	7	10	10	11	11
DR Winter - CA	0	0	0	0	0	0	0	0	0	0
DR Summer - ID	30	31	31	56	56	57	62	63	63	76
DR Winter - ID	0	0	0	0	0	0	0	0	0	0
DR Summer - OR	37	90	141	144	165	195	198	200	238	245
DR Winter - OR	118	118	118	118	118	118	118	118	118	118
DR Summer - UT	173	186	199	212	229	244	260	327	347	470
DR Winter - UT	0	0	0	0	0	0	0	0	0	0
DR Summer - WA	27	27	39	39	51	52	52	53	56	57
DR Winter - WA	11	11	11	11	11	11	11	11	11	11
DR Summer - WY	58	58	58	58	58	58	63	63	64	64
DR Winter - WY	0	0	0	0	0	0	0	0	0	0

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	13,832	20,186	26,823	33,469	39,967	46,864	53,356	59,296	64,727
ID	17,544	42,512	63,201	85,809	109,760	134,567	155,257	185,725	216,663	246,826	274,451
OR	191,834	360,054	544,971	732,678	926,395	1,120,867	1,304,185	1,502,299	1,698,056	1,866,326	2,035,086
UT	272,934	573,161	973,115	1,465,931	1,942,259	2,401,553	2,811,536	3,374,021	3,939,353	4,456,818	4,945,653
WA	46,965	80,143	119,026	163,691	208,892	257,563	310,527	365,528	421,560	474,884	526,589
WY	41,384	83,765	158,486	241,607	322,779	405,630	475,624	570,993	668,426	760,809	845,821
Total System	573,969	1,146,820	1,872,632	2,709,903	3,536,908	4,353,650	5,097,096	6,045,431	6,997,414	7,864,959	8,692,326

Cumulative Energy Efficiency Energy (MWh) Selected by State and Year

State	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
CA	70,047	73,914	77,871	81,595	84,558	87,533	89,500	92,087	94,082	95,444
ID	300,295	314,332	338,172	361,106	379,984	399,350	399,519	417,792	434,116	443,344
OR	2,183,430	2,306,242	2,453,148	2,592,107	2,736,233	2,867,688	2,959,241	2,777,170	2,893,594	3,028,081
UT	5,204,249	5,562,189	5,964,200	6,351,161	6,691,431	7,035,184	6,929,216	7,234,120	7,480,153	7,696,114
WA	572,972	617,392	656,778	693,586	724,169	755,016	779,461	807,176	830,083	848,578
WY	917,119	958,608	1,018,963	1,075,940	1,124,893	1,177,655	1,196,770	1,244,308	1,283,918	1,322,306
Total System	9,248,111	9,832,678	10,509,132	11,155,495	11,741,267	12,322,426	12,353,707	12,572,655	13,015,947	13,433,866

For the 20-year assumed nameplate capacity contributions (MW impacts) by state and year associated with the energy efficiency resource selections above, see Volume I, Chapter 9 (Modeling and Portfolio Selection).

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

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

Similar to 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 smart grid 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

[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 - 20252023 Flexible Resource Costs as Compared to 2023 Costs, $/MWh

Note – Table F.2 will be updated for the March 31, 2025 IRP filing based on final preferred portfolio results.

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

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

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 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

[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.

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

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 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

[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

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

[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.

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,

[15] Order No. 764 at P 281; Order No. 764-B at P 210.

"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.

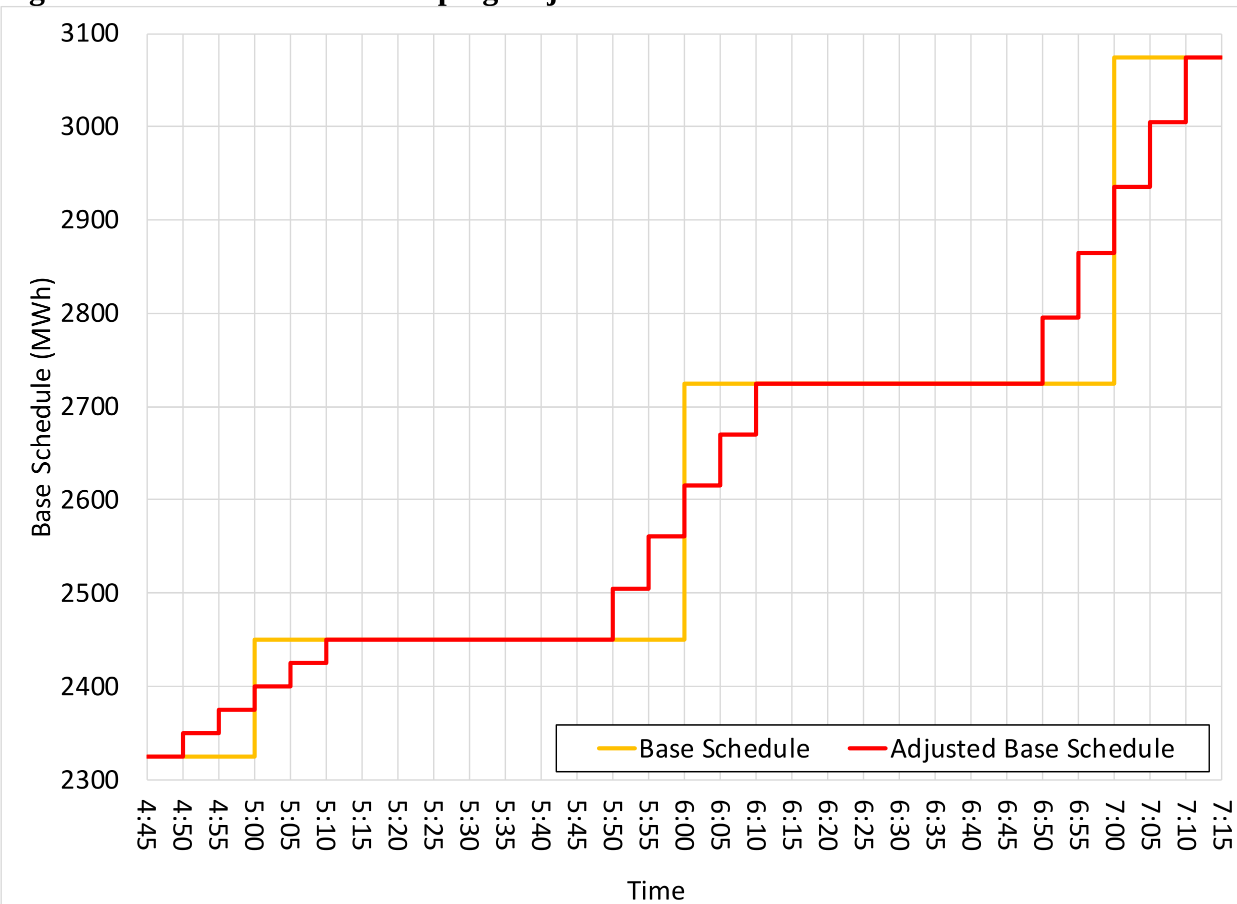
Base Schedule Ramping Adjustment

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

[16] Order No. 764 at P 20 (emphasis added).
[17] *Id.* at P 92.

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. 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

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

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

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 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.

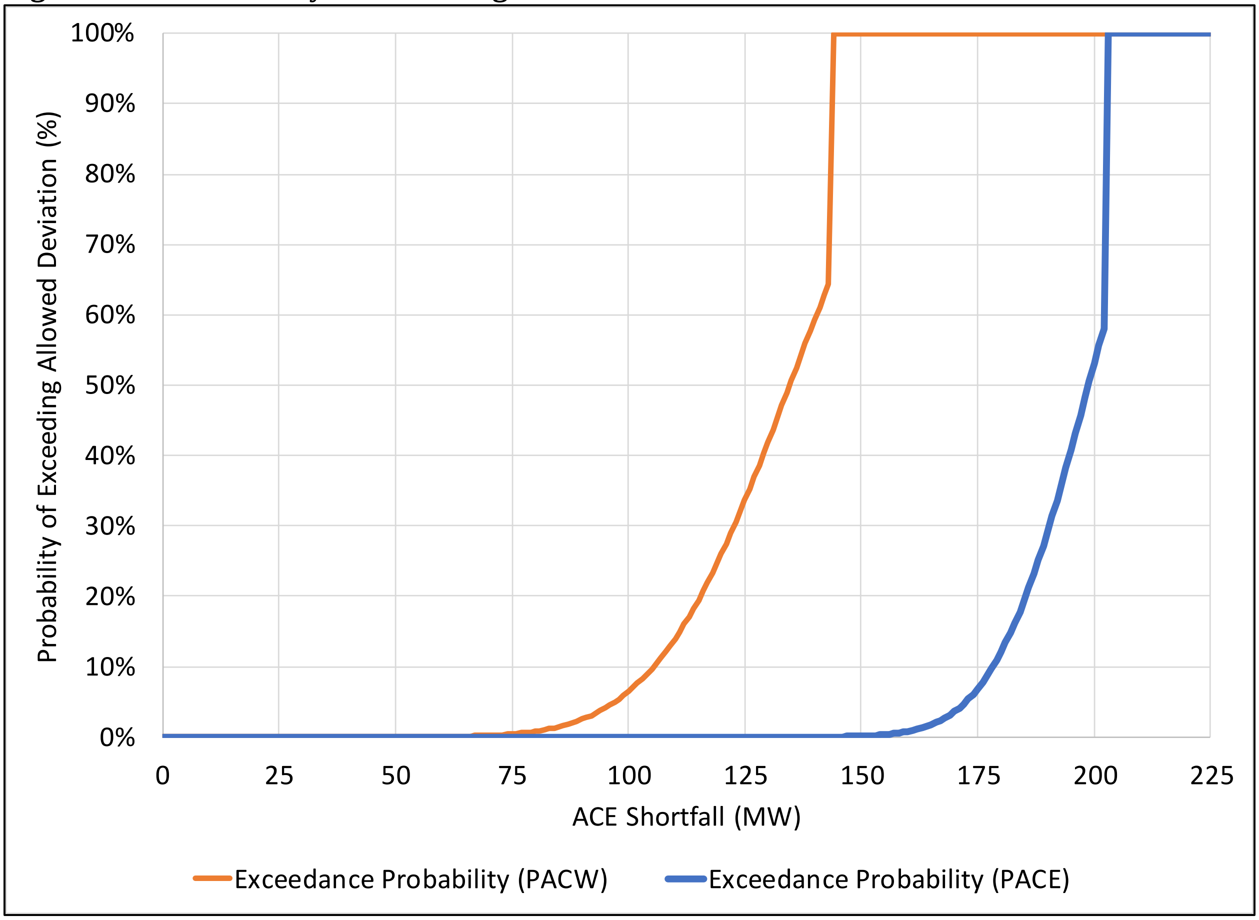
The Balancing Authority ACE Limit is specific to each BAA and is dynamic, varying as a function of interconnection frequency. When WECC frequency is close to 60 Hz, the Balancing Authority ACE Limit is large and large deviations in ACE are allowed. As WECC frequency drops further and further below 60 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 (50th 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 Forecast^1 + Constant
Wind Error: Wind Forecast^2 + Wind Forecast^1
Solar Error: Solar Forecast^4 + Solar Forecast^3 + Solar Forecast^2 + Solar Forecast^1
Non-VER Error: Non-VER Forecast^2 + Non-VER 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

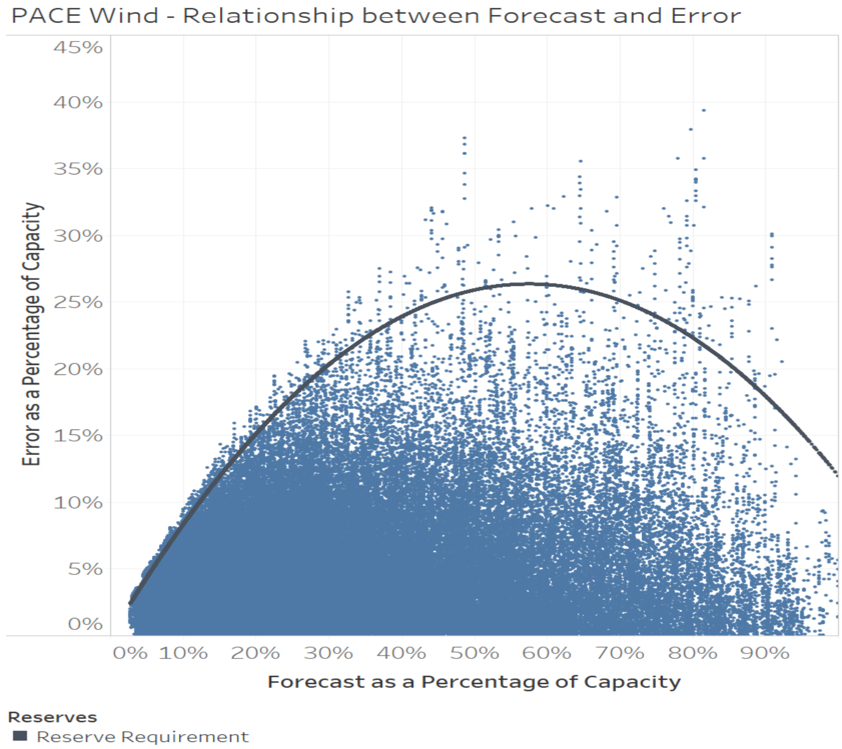


Figure F.4 - Wind Regulation Reserve Requirements by Forecast Capacity Factor - PACW

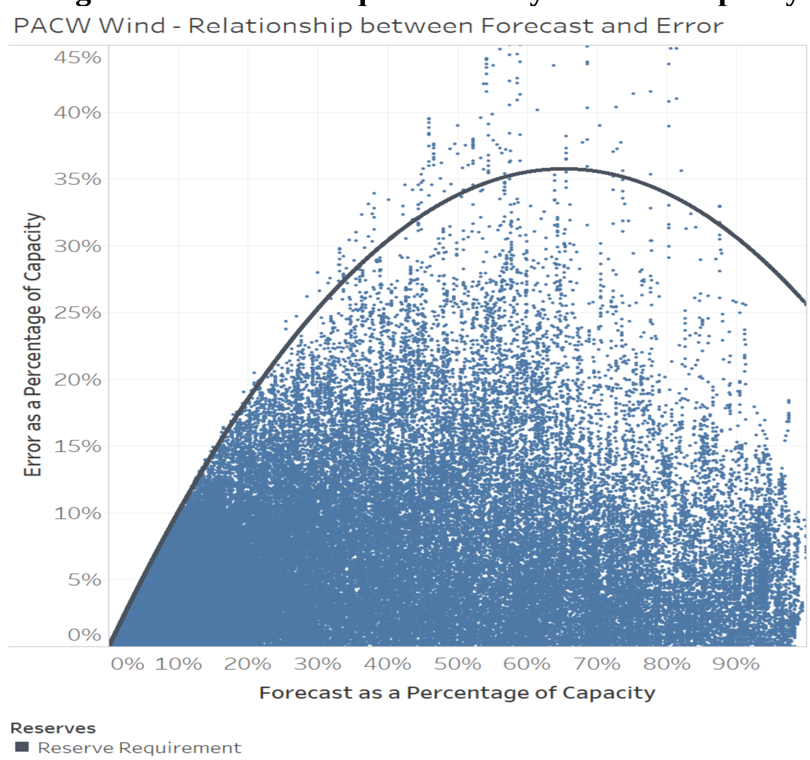


Figure F.5 - Solar Regulation Reserve Requirements by Forecast Capacity Factor - PACE

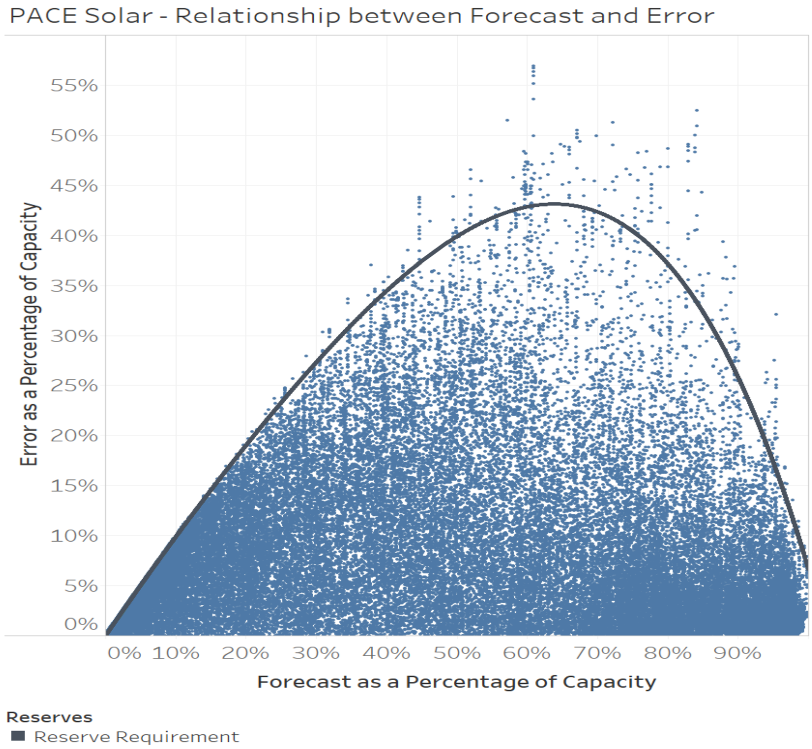


Figure F.6 - Solar Regulation Reserve Requirements by Forecast Capacity Factor - PACW

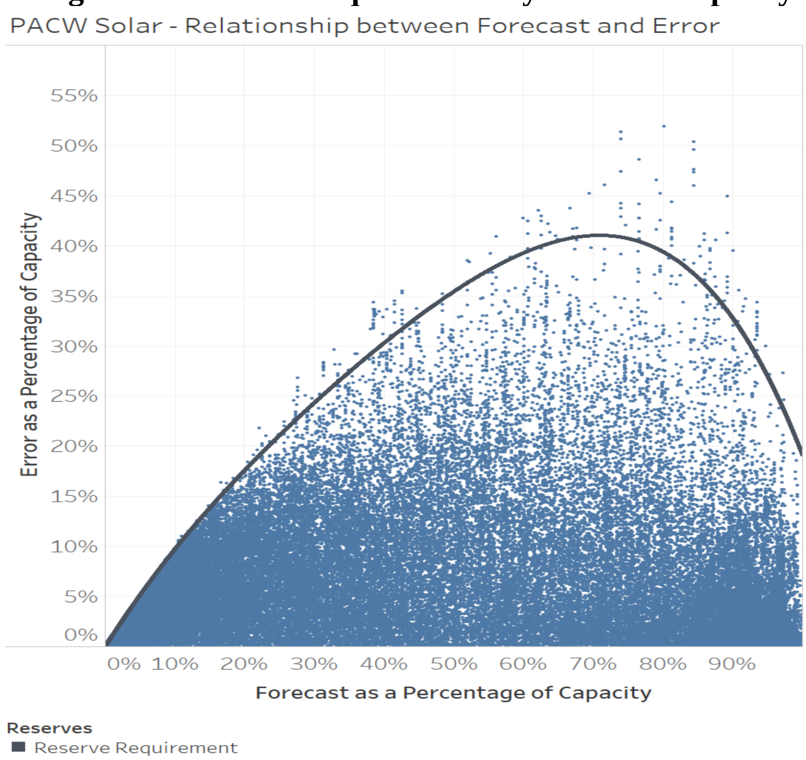


Figure F.7 – Non-VER Regulation Reserve Requirements by Capacity Factor - PACE

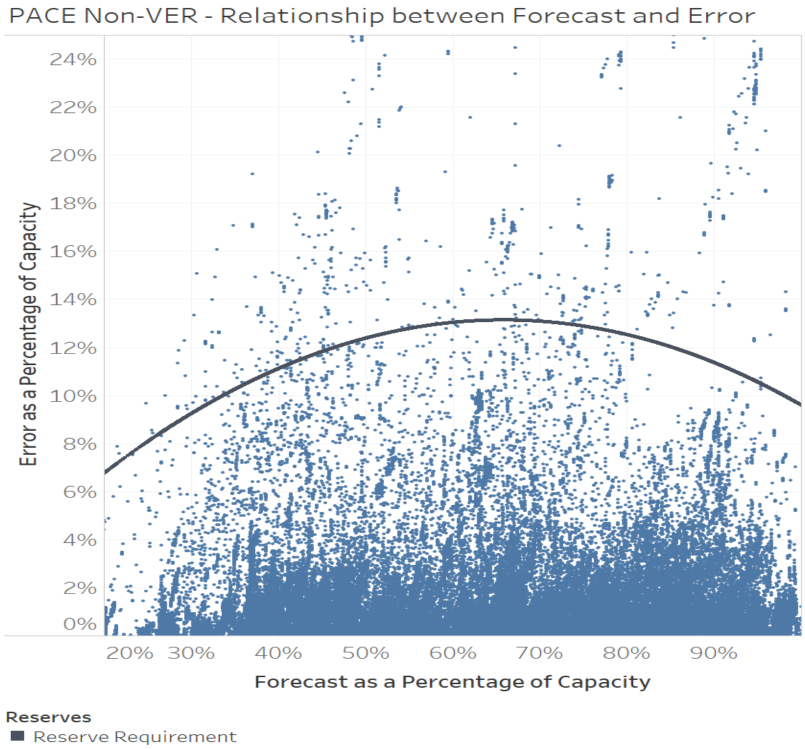


Figure F.8 – Non-VER Regulation Reserve Requirements by Capacity Factor - PACW

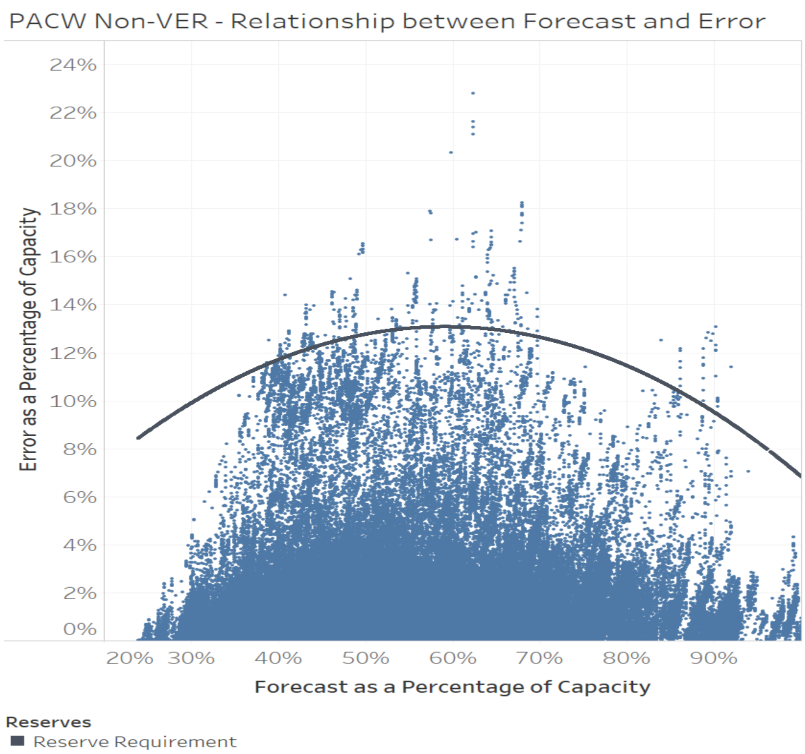


Figure F.9 – Stand-alone Load Regulation Reserve Requirements - PACE

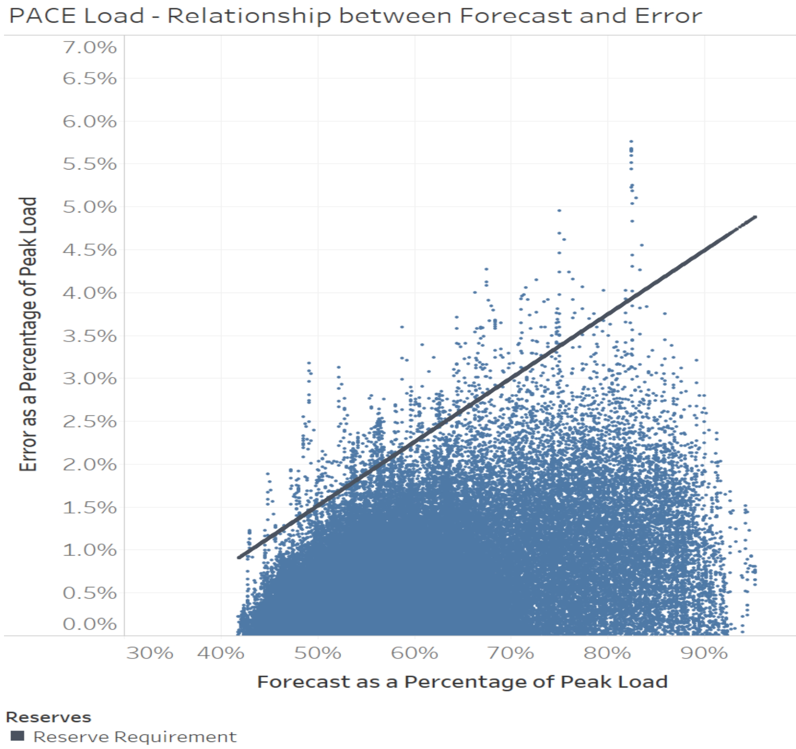
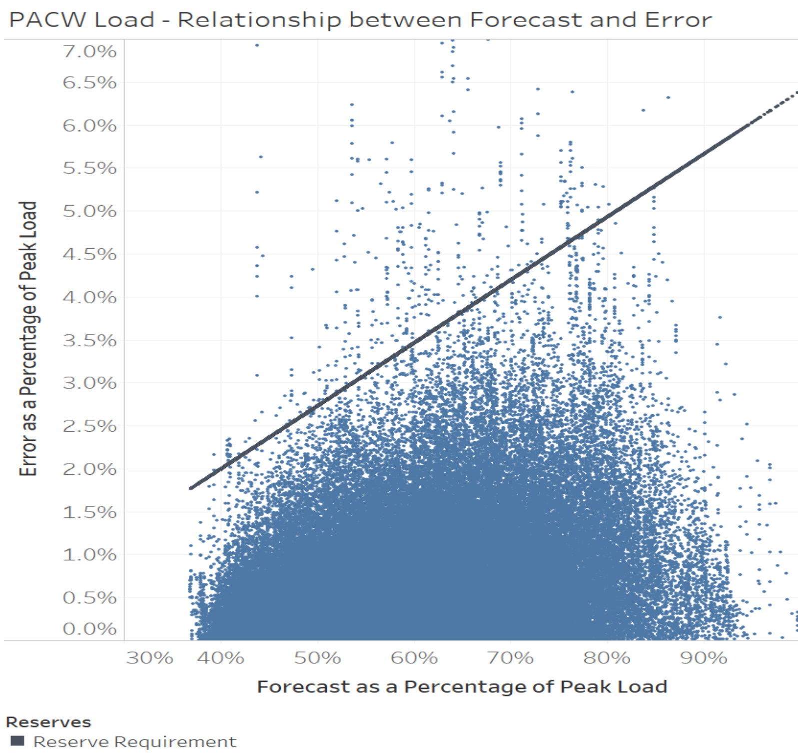


Figure F.10 – Stand-alone Load Regulation Reserve Requirements - PACW



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 97.5th percentile of incremental requirements versus Requirement 2 in that interval was evaluated. At the 97.5th 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 97.5th 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	%								
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%
%		**50%**	**100%**	**166%**	**329%**	**493%**	**656%**	**820%**	**983%**
MW		**428**	**855**	**1,462**	**2,502**	**3,542**	**4,582**	**5,622**	**6,662**

East Solar Capacity

☐ 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	%	50% / 111 MW	100% / 221 MW	166% / 321 MW	329% / 1,041 MW	493% / 1,761 MW	656% / 2,481 MW	820% / 3,201 MW	983% / 3,921 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%		**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%

West Solar Capacity

2018-2019 Actual Wind and Solar Capacity (boxed cell: 42.4%)

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.

Note – Incremental regulation reserve requirements discussed below will be updated for the March 31, 2025 IRP filing based on final preferred portfolio results.

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 starting in the first year proxy resources are generally available and extending to the end of the IRP study horizon (2028-2045). The change in resources is applied equally between 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 XX% 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 starting in the first year proxy resources are generally available and extending to the end of the IRP study horizon (2028-2045). The reduction in resources is applied equally between 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 XX% 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 2021 FRS are also shown. Integration costs are high in the near term, as market prices are currently high and flexible capacity is somewhat limited. Integration costs fall as energy storage resources are added to the portfolio, as they can provide free operating reserves 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

> ***Note – Figure F.11 will be updated for the March 31, 2025 IRP filing based on final preferred portfolio results.***

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; and

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)

Note – Table F.9 will be updated for the March 31, 2025 IRP filing based on the final preferred portfolio results.

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.

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

Note – Table F.10 will be updated for the March 31, 2025 IRP filing based on the final preferred portfolio results.

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 could increase the available response beyond that 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)

Note – Figure F.12 will be updated for the March 31, 2025 IRP filing based on the final preferred portfolio results.

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

Note – Figure F.13 will be updated for the March 31, 2025 IRP filing based on the final preferred portfolio results.

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

[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 2025 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.

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 approximately a 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 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%					

Table G.4 – 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%					

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. See the below tables for a list of cases presented here.

Table I.1 – Price-Policy Scenario Portfolios

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

Table I.2 – Variant Portfolios

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 gas convert by January 1, 2032	-
Offshore Wind	Counterfactual to the Preferred Portfolio selection	-
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
No Forward Technology	No nuclear, hydro storage or biodiesel peaking	See the No Nuclear variant

2025 IRP Portfolio Summaries

Preferred Portfolio

LT_25I.LP.iLT.21.Integrated.EP.2409MN.Base IntTrans_106955 v78.1

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	89	89	238	262	270	285	342	329	308	282	265	255	250	233	220	208	201	232	283	269	239	5,149
DSM - Demand Response	18	40	11	144	33	81	13	36	2	46	24	12	66	76	42	51	46	33	71	63	144	1,052
Renewable - Wind	-	-	-	486	804	-	-	451	-	-	3	2,327	-	-	-	-	-	-	-	-	-	4,071
Renewable - Small Scale Wind	-	-	-	-	380	505	4	85	-	-	-	246	4	37	9	-	-	236	802	-	-	2,308
Renewable - Utility Solar	-	-	245	182	-	848	896	805	49	5	-	2,221	4	-	-	-	237	-	-	-	-	5,492
Renewable - Small Scale Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	520	1,297	116	-	39	-	416	3	317	176	-	11	253	10	81	105	488	257	279	15	4,383
Renewable - Battery (Long Duration)	-	-	1	26	62	655	166	22	93	88	67	-	-	326	466	312	325	-	264	332	80	3,285
Other Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Existing Unit Changes																						
Coal Plant Retirements - Minority Owned	-	(82)	-	(33)	(123)	(148)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(386)
Coal Plant Retirements	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)
Coal Plant Ceases as Coal	-	(357)	-	-	(205)	(700)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,262)
Coal - CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
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	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**107**	**502**	**1,792**	**961**	**1,426**	**1,966**	**1,212**	**2,144**	**455**	**735**	**535**	**5,061**	**235**	**893**	**747**	**652**	**516**	**989**	**1,630**	**710**	**456**	

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	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	89	89	233	253	261	275	325	322	302	277	260	248	250	233	219	208	201	232	283	269	235	5,064
DSM - Demand Response	18	25	7	38	86	60	7	4	2	3	1	-	255	85	47	46	46	27	79	61	43	940
Renewable - Wind	-	-	222	166	-	594	-	-	-	-	3	-	31	256	-	-	-	-	-	-	-	1,272
Renewable - Small Scale Wind	-	-	-	-	380	505	4	85	-	-	-	246	4	37	9	-	-	-	-	-	-	1,270
Renewable - Utility Solar	-	-	109	165	-	848	102	807	45	4	2	2,221	4	-	-	-	-	-	-	-	-	4,307
Renewable - Small Scale Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	520	1,091	10	-	19	5	3	25	3	4	-	-	146	6	7	16	504	67	6	6	2,438
Renewable - Battery (Long Duration)	-	-	1	26	62	655	166	22	93	88	67	-	-	130	174	634	381	97	277	332	80	3,285
Other Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Existing Unit Changes																						
Coal Plant Retirements - Minority Owned	-	(82)	-	(33)	(123)	(148)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(386)
Coal Plant Retirements	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)
Coal Plant Ceases as Coal	-	(357)	-	-	(205)	(700)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,262)
Coal - CCS	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	526
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	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**107**	**487**	**1,663**	**403**	**666**	**3,035**	**400**	**1,243**	**467**	**372**	**337**	**2,715**	**444**	**855**	**455**	**895**	**246**	**860**	**659**	**435**	**344**	

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	-	-	-	-	221	-	-	-	-	-	-	-	-	-	-	-	179	-	-	-	-	400
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	500
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	89	89	214	236	243	252	326	322	300	283	265	258	260	243	229	217	210	230	285	271	236	5,058
DSM - Demand Response	18	17	4	8	37	-	185	35	-	54	57	-	26	44	42	52	24	45	30	78	40	796
Renewable - Wind	-	-	1,008	-	594	-	-	17	-	-	3	1,990	130	-	-	-	-	-	-	-	-	3,742
Renewable - Small Scale Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	121	157	-	-	-	194	660	1,132
Renewable - Utility Solar	-	-	136	17	-	-	794	630	4	1	-	-	-	406	-	-	237	-	-	-	-	2,225
Renewable - Small Scale Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	520	490	6	-	-	5	747	-	296	196	-	-	269	28	471	177	152	347	285	15	4,004
Renewable - Battery (Long Duration)	-	-	-	-	-	-	-	25	-	-	132	-	-	121	139	224	92	395	107	108	-	1,343
Other Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Existing Unit Changes																						
Coal Plant Retirements - Minority Owned	-	(82)	-	(33)	(123)	(148)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(386)
Coal Plant Retirements	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)
Coal Plant Ceases as Coal	-	(357)	-	-	(205)	(1,030)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,592)
Coal - CCS	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	526
Coal - Gas Conversions	-	357	-	-	205	330	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	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)	-	(50)
Expire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**107**	**479**	**1,852**	**12**	**972**	**331**	**1,101**	**1,776**	**304**	**631**	**653**	**2,248**	**316**	**1,051**	**559**	**1,121**	**521**	**822**	**722**	**703**	**931**	

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	89	89	203	247	256	271	331	319	298	273	255	259	250	233	220	208	207	232	283	271	239	5,033
DSM - Demand Response	18	1	-	157	40	33	-	46	-	86	29	27	17	17	47	47	46	33	74	61	144	923
Renewable - Wind	-	-	-	486	211	-	-	1,045	-	-	-	340	-	-	-	-	-	-	-	-	-	2,082
Renewable - Small Scale Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	143	390	802	-	-	1,335
Renewable - Utility Solar	-	-	-	-	-	-	-	1,675	-	4	-	670	4	-	-	-	-	-	-	-	-	2,353
Renewable - Small Scale Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	520	4	444	355	134	-	389	-	232	4	-	11	6	6	-	14	462	65	6	6	2,658
Renewable - Battery (Long Duration)	-	-	-	-	-	130	-	-	-	100	78	368	383	359	466	312	325	-	51	332	70	2,974
Other Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Existing Unit Changes																						
Coal Plant Retirements - Minority Owned	-	(82)	-	(33)	(123)	(148)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(386)
Coal Plant Retirements	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)
Coal Plant Ceases as Coal	-	(357)	-	-	(205)	(700)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,262)
Coal - CCS	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	526
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	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**107**	**463**	**207**	**1,079**	**739**	**647**	**122**	**3,474**	**298**	**692**	**366**	**1,664**	**565**	**583**	**739**	**567**	**337**	**1,117**	**1,228**	**437**	**439**	

No CCS

LT_25I.LP.iLT.21.Integrated.EP.2409MN.No CCS IntTrans_107094 v78.5

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	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40	-	-	-	-	-	-	40
Nuclear	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	500
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	89	89	238	262	270	285	343	329	308	282	270	255	250	234	220	208	202	232	287	272	239	5,164
DSM - Demand Response	18	40	11	139	38	81	13	36	2	46	24	12	66	76	45	48	60	68	23	153	53	1,052
Renewable - Wind	-	-	439	970	602	-	-	-	-	-	273	2,634	-	-	-	-	-	-	-	-	-	4,918
Renewable - Small Scale Wind	-	-	-	-	380	505	4	85	-	-	-	246	4	37	9	-	-	-	-	176	660	2,106
Renewable - Utility Solar	-	-	245	182	-	848	896	805	567	5	-	4,291	2	-	-	-	237	-	-	-	-	8,078
Renewable - Small Scale Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	520	1,297	16	43	19	4	464	14	242	389	-	438	417	65	488	214	214	355	592	15	5,806
Renewable - Battery (Long Duration)	-	-	1	26	62	655	166	22	93	88	67	-	-	130	174	634	381	97	277	332	80	3,285
Other Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Existing Unit Changes																						
Coal Plant Retirements - Minority Owned	-	(82)	-	(33)	(123)	(148)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(386)
Coal Plant Retirements	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)
Coal Plant Ceases as Coal	-	(357)	-	-	(205)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(562)
Coal - CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
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	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**107**	**502**	**2,231**	**1,340**	**1,272**	**2,646**	**1,217**	**1,741**	**984**	**660**	**1,023**	**7,438**	**660**	**862**	**553**	**1,378**	**696**	**611**	**895**	**1,292**	**1,025**	

No Nuclear

LT_25I.LP.iLT.21.Integrated.EP.2409MN.No Nuclear IntTrans_106164 v76

Summary Portfolio Capacity by Resource Type and Year, Installed MW

Resource	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	-	-	-	-	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	89	89	238	262	275	289	345	331	308	283	265	252	250	233	227	214	207	235	286	275	239	5,192
DSM - Demand Response	18	40	19	126	53	94	23	21	18	39	16	1	136	28	42	77	23	29	72	62	144	1,081
Renewable - Wind	-	-	-	422	834	-	-	412	-	-	199	1,374	616	-	-	-	-	-	-	-	-	3,857
Renewable - Small Scale Wind	-	-	-	-	-	246	7	-	-	-	21	207	111	17	9	-	-	-	-	105	211	934
Renewable - Utility Solar	-	-	290	237	-	44	181	451	521	2	2,079	2,103	4	-	-	-	-	-	-	-	-	5,912
Renewable - Small Scale Solar	-	-	-	-	-	591	-	1	26	17	-	-	-	-	-	-	-	-	-	-	-	635
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	520	734	124	318	879	110	317	15	309	148	-	-	314	14	861	174	95	108	43	96	5,179
Renewable - Battery (Long Duration)	-	-	251	109	-	123	249	97	-	258	126	-	36	152	120	277	229	246	160	104	33	2,570
Other Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Existing Unit Changes																						
Coal Plant Retirements - Minority Owned	-	(82)	-	(33)	(123)	(148)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(386)
Coal Plant Retirements	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)
Coal Plant Ceases as Coal	-	(357)	-	-	(205)	(700)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,262)
Coal - CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
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	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**107**	**502**	**1,532**	**1,025**	**1,397**	**1,319**	**706**	**1,630**	**888**	**905**	**2,854**	**3,937**	**1,053**	**712**	**412**	**1,429**	**235**	**605**	**579**	**356**	**701**	

No Coal 2032

LT_25I.LP.iLT.21.Integrated.EP.2409MN.No Coal 2032 IntTrans_107095 v78.5

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	-	-	-	-	199	-	-	298	-	-	-	-	-	-	-	-	-	-	-	-	-	497
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	500
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	89	89	238	259	266	281	336	329	303	282	265	248	250	234	220	208	201	232	283	269	240	5,122
DSM - Demand Response	18	40	11	141	32	60	47	27	2	46	16	12	66	84	42	48	48	34	71	62	43	950
Renewable - Wind	-	-	-	1,077	594	153	78	350	-	-	2	3,132	178	-	-	-	-	-	-	-	-	5,564
Renewable - Small Scale Wind	-	-	-	-	380	505	4	85	-	-	-	246	4	37	9	-	-	-	-	176	660	2,106
Renewable - Utility Solar	-	-	245	182	-	848	896	805	87	5	480	4,291	4	-	-	-	237	-	-	-	-	8,080
Renewable - Small Scale Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	520	1,297	116	-	19	4	639	12	71	365	-	56	602	220	422	128	227	242	411	17	5,368
Renewable - Battery (Long Duration)	-	-	1	26	62	655	166	22	93	88	67	-	-	130	174	634	381	97	277	332	80	3,285
Other Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Existing Unit Changes																						
Coal Plant Retirements - Minority Owned	-	(82)	-	(33)	(123)	(148)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(386)
Coal Plant Retirements	-	-	-	(220)	-	-	-	(268)	-	-	-	-	-	-	-	-	-	-	-	-	-	(488)
Coal Plant Ceases as Coal	-	(357)	-	-	(205)	(3,097)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(3,659)
Coal - CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	357	-	-	205	3,097	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3,659
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	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**107**	**502**	**1,792**	**1,546**	**1,410**	**2,774**	**1,322**	**2,287**	**497**	**489**	**1,195**	**7,929**	**458**	**1,055**	**665**	**1,312**	**597**	**590**	**826**	**1,017**	**1,018**	

Offshore Wind

LT_25I.LP.iLT.21.Integrated.EP.2409MN.OSWind IntTrans_106388 v76.6

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	89	89	238	259	270	285	338	329	308	283	265	252	250	233	219	208	207	232	283	271	236	5,144
DSM - Demand Response	18	40	23	135	38	49	7	37	18	30	24	1	136	47	42	72	24	28	79	61	43	952
Renewable - Wind	-	-	-	452	792	-	200	-	41	-	270	864	1,126	-	-	-	-	-	-	-	-	3,745
Renewable - Small Scale Wind	-	-	-	-	-	113	-	-	-	-	-	-	-	-	-	-	-	79	1	-	-	193
Renewable - Utility Solar	-	-	297	101	-	385	411	634	521	4	-	405	4	-	-	670	-	-	393	-	-	3,825
Renewable - Small Scale Solar	-	-	-	-	-	731	55	72	-	-	3	165	54	8	9	-	-	-	-	-	244	1,341
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	520	1,360	328	220	558	140	69	122	118	47	-	-	127	10	1,067	322	405	313	244	15	5,985
Renewable - Battery (Long Duration)	-	-	45	15	79	166	-	31	-	339	178	-	-	382	675	305	206	274	327	362	122	3,506
Other Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Existing Unit Changes																						
Coal Plant Retirements - Minority Owned	-	(82)	-	(33)	(123)	(148)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(386)
Coal Plant Retirements	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)
Coal Plant Ceases as Coal	-	(357)	-	-	(205)	(700)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,262)
Coal - CCUS	-	-	-	-	-	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)	(2)	(52)
Expire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**107**	**502**	**1,963**	**1,035**	**1,276**	**2,366**	**942**	**1,172**	**1,010**	**771**	**787**	**1,687**	**1,470**	**765**	**955**	**2,322**	**361**	**1,018**	**1,349**	**705**	**638**	

LN

LT_25I.LP.iLT.21.Integrated.EP.2409LN.Base IntTrans_109399 v79.5

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	-	-	-	-	410	424	-	-	-	-	-	-	-	-	318	-	212	410	-	-	-	1,774
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	500
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	89	89	237	257	265	280	334	328	307	281	264	254	249	232	218	206	199	225	276	266	227	5,083
DSM - Demand Response	18	40	25	138	53	34	13	36	18	31	16	21	85	76	43	50	46	33	72	118	88	1,054
Renewable - Wind	-	-	-	-	594	-	-	-	-	-	3	3,015	-	-	-	-	-	-	-	-	-	3,612
Renewable - Small Scale Wind	-	-	-	-	500	349	34	26	-	29	29	29	41	33	9	109	-	-	-	194	660	2,042
Renewable - Utility Solar	-	-	136	317	49	683	985	452	522	300	105	1	4	6	-	-	231	-	-	-	-	3,791
Renewable - Small Scale Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	520	1,235	160	3	-	-	401	6	242	546	156	368	245	412	863	211	456	380	851	9	7,064
Renewable - Battery (Long Duration)	-	-	93	-	2	803	151	66	102	58	-	-	-	58	94	554	89	109	257	345	23	2,804
Other Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Existing Unit Changes																						
Coal Plant Retirements - Minority Owned	-	(82)	-	(33)	(123)	(148)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(386)
Coal Plant Retirements	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)
Coal Plant Ceases as Coal	-	(357)	-	-	(205)	(1,030)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,592)
Coal - CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	357	-	-	205	330	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	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	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**107**	**502**	**1,726**	**617**	**1,753**	**2,126**	**1,308**	**1,309**	**955**	**938**	**963**	**3,476**	**647**	**618**	**1,094**	**1,782**	**590**	**1,233**	**938**	**1,541**	**985**	

MR

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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	-	-	-	-	-	-	-	479	-	-	-	-	-	-	-	-	-	-	-	-	-	479
Nuclear	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	500
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	89	89	238	259	266	285	338	329	308	282	265	249	250	239	227	214	210	235	286	271	239	5,168
DSM - Demand Response	18	40	11	126	43	76	12	39	2	46	16	12	80	80	42	48	48	34	71	43	62	949
Renewable - Wind	-	-	-	1,417	594	-	-	451	-	-	3	2,954	187	-	-	-	-	-	-	-	-	5,606
Renewable - Small Scale Wind	-	-	-	-	-	745	-	60	52	-	-	300	98	9	9	-	-	552	28	414	40	2,307
Renewable - Utility Solar	-	-	136	107	-	505	794	1,081	522	1	-	2,736	2	406	-	-	237	-	-	-	-	6,527
Renewable - Small Scale Solar	-	-	-	61	-	110	-	27	-	-	-	-	-	-	-	-	-	-	-	-	-	198
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	520	1,135	26	181	390	108	537	37	197	277	-	176	341	73	81	79	651	589	639	15	6,052
Renewable - Battery (Long Duration)	-	-	-	-	-	378	-	-	-	-	-	-	-	60	167	496	261	50	108	71	-	1,591
Other Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Existing Unit Changes																						
Coal Plant Retirements - Minority Owned	-	(82)	-	(33)	(123)	(148)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(386)
Coal Plant Retirements	-	-	-	(220)	-	-	-	(268)	-	-	-	-	-	-	-	-	-	-	-	-	-	(488)
Coal Plant Ceases as Coal	-	(357)	-	-	(205)	(3,097)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(3,659)
Coal - CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	357	-	-	205	2,397	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2,959
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	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**107**	**502**	**1,520**	**1,741**	**961**	**2,042**	**1,043**	**2,735**	**921**	**523**	**561**	**6,251**	**693**	**1,103**	**518**	**839**	**437**	**1,522**	**1,035**	**1,205**	**334**	

HH

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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	89	89	244	268	276	291	347	333	312	286	268	268	261	243	229	217	210	235	286	272	240	5,264
DSM - Demand Response	18	40	23	134	45	34	13	36	2	50	16	12	105	25	39	104	50	19	81	28	65	939
Renewable - Wind	-	-	1,187	721	975	233	-	451	-	-	3	2,492	-	-	-	-	-	-	-	-	-	6,062
Renewable - Small Scale Wind	-	-	-	-	133	876	89	-	-	-	14	172	76	75	49	-	402	486	120	125	37	2,654
Renewable - Utility Solar	-	-	419	411	-	546	2,865	452	4	1	-	2,648	800	406	-	-	237	-	-	-	-	8,789
Renewable - Small Scale Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,121	1,121
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	520	1,133	66	108	347	141	452	141	12	200	-	74	50	12	193	136	505	399	276	34	4,799
Renewable - Battery (Long Duration)	-	-	-	-	-	243	-	-	-	86	131	-	274	375	106	555	-	-	135	346	90	2,341
Other Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Existing Unit Changes																						
Coal Plant Retirements - Minority Owned	-	(82)	-	(33)	(123)	(148)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(386)
Coal Plant Retirements	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)
Coal Plant Ceases as Coal	-	(357)	-	-	(205)	(1,030)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,592)
Coal - CCUS	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	526
Coal - Gas Conversions	-	357	-	-	205	330	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	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	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**107**	**502**	**3,006**	**1,345**	**1,414**	**2,649**	**3,246**	**1,724**	**459**	**432**	**632**	**5,592**	**1,490**	**1,142**	**435**	**1,069**	**637**	**1,245**	**974**	**814**	**1,565**	

SC

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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	-	-	-	-	199	-	-	199	-	-	-	-	-	-	-	-	-	-	-	-	-	398
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	500
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	89	89	244	265	272	286	347	333	310	283	265	258	252	240	227	209	210	234	286	271	235	5,205
DSM - Demand Response	18	40	13	27	115	21	82	26	2	46	16	1	32	91	94	30	67	27	77	27	40	892
Renewable - Wind	-	-	1,417	-	594	-	-	451	-	-	297	3,236	152	-	-	-	-	-	-	-	-	6,147
Renewable - Small Scale Wind	-	-	20	-	302	616	35	89	1	-	8	215	32	103	119	-	-	875	92	-	454	2,961
Renewable - Utility Solar	-	-	336	500	-	281	1,156	415	55	1	66	3,363	1,584	564	139	-	237	793	-	-	-	9,490
Renewable - Small Scale Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	156	156
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	520	1,011	98	-	708	2	592	91	14	181	-	13	313	307	94	393	41	370	695	139	5,582
Renewable - Battery (Long Duration)	-	-	-	-	-	197	-	-	-	103	78	-	24	-	14	399	130	469	373	108	-	1,895
Other Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Existing Unit Changes																						
Coal Plant Retirements - Minority Owned	-	(82)	-	(33)	(123)	(148)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(386)
Coal Plant Retirements	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)
Coal Plant Ceases as Coal	-	(357)	-	-	(205)	(1,030)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,592)
Coal - CCUS	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	526
Coal - Gas Conversions	-	357	-	-	205	330	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	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	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**107**	**502**	**3,041**	**635**	**1,359**	**2,188**	**1,413**	**2,105**	**459**	**444**	**911**	**7,073**	**1,989**	**1,279**	**900**	**732**	**639**	**2,439**	**1,151**	**868**	**1,002**	

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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☐ Private and Confidential	For disclosure only to individuals directly concerned with the subject matter of the document within the Customer's organization.
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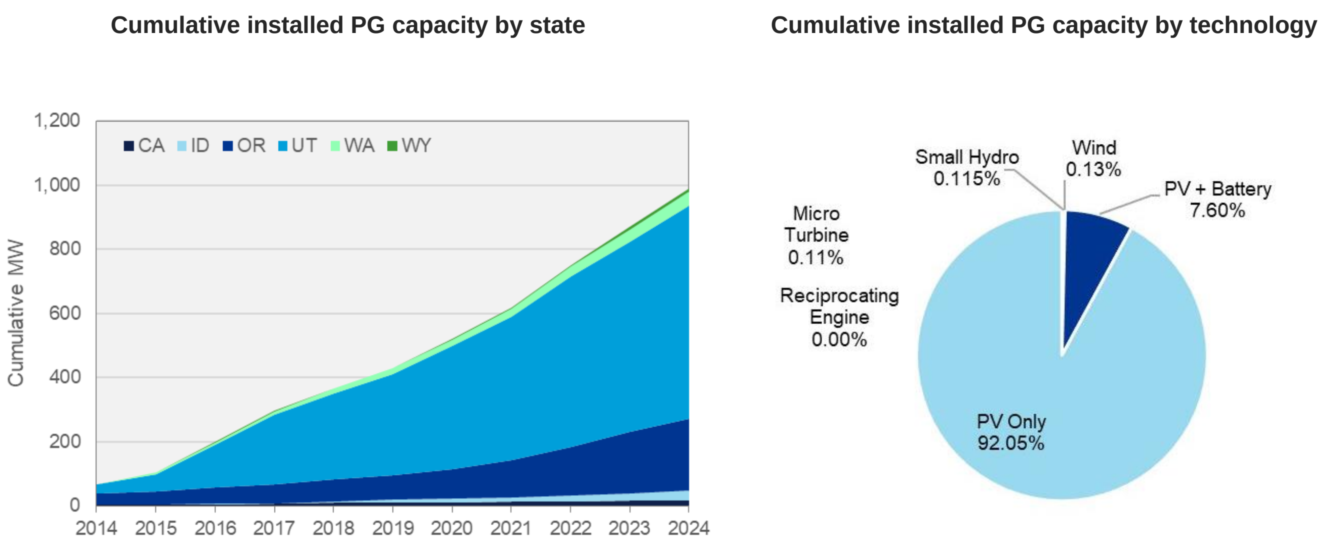
1   EXECUTIVE SUMMARY

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



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.

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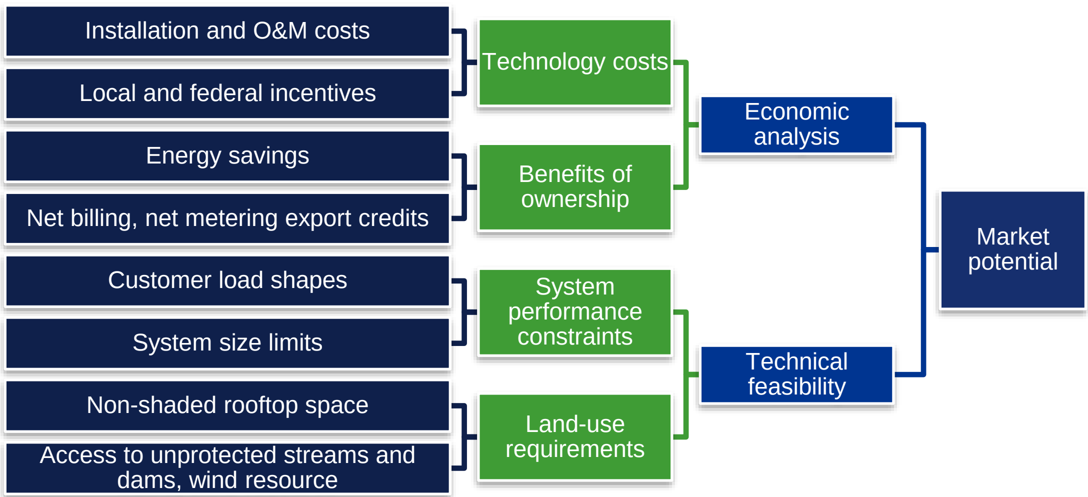
[2] U.S. Energy Information Administration, Annual Energy Outlook 2023 (AEO2023), (Washington, DC, March 2023).

[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



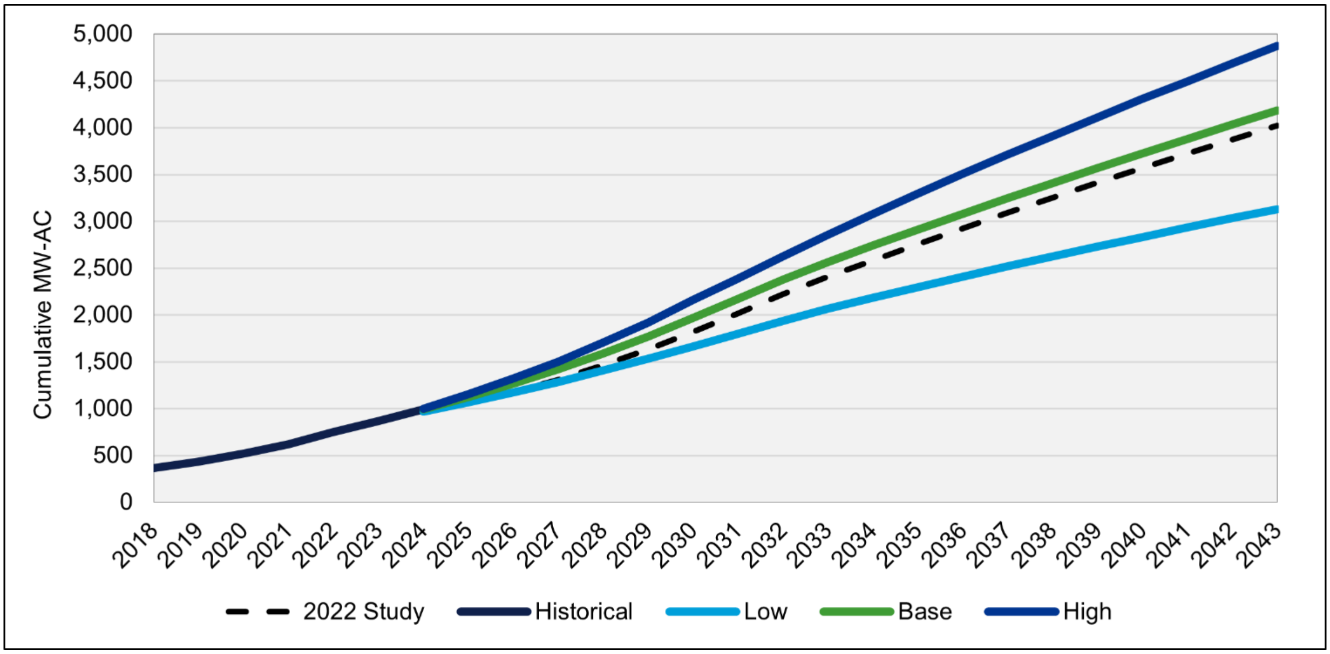
DNV used technology and sector-specific Bass diffusion curves to model market adoption and derive total market potential. Bass diffusion curves are widely used for forecasting technology adoption. Diffusion curves typically take the form of an S-curve with an initial period of slow early adoption that 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.

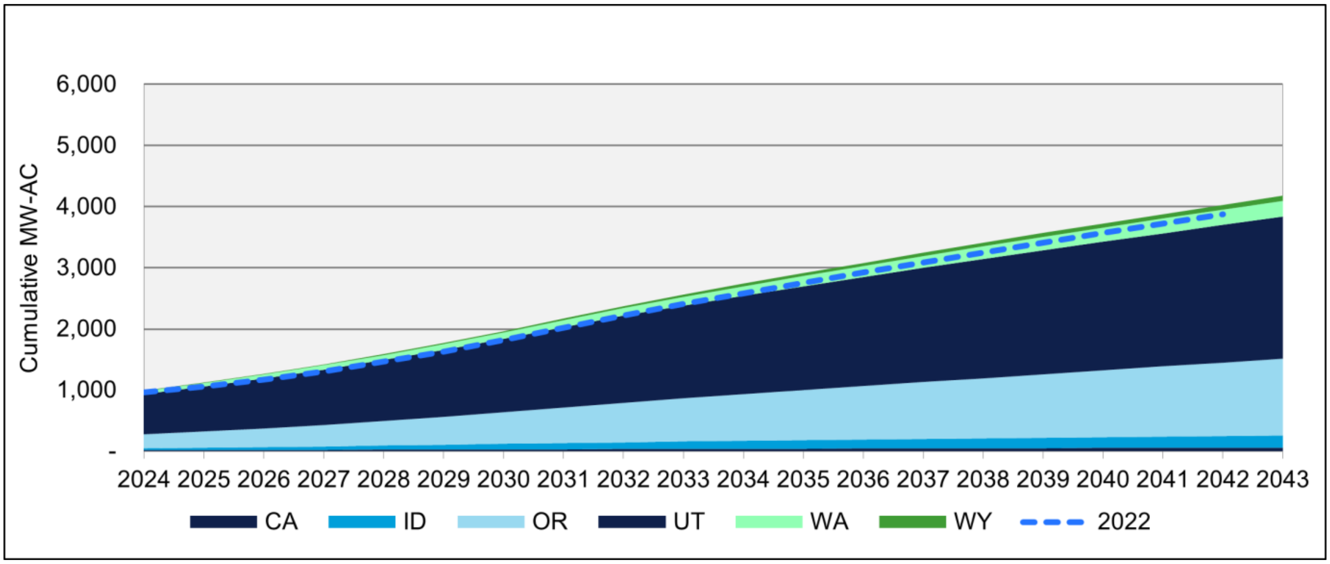
Figure 1-3. Cumulative historical and new capacity installed by scenario (MW-AC), 2024-2043



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.

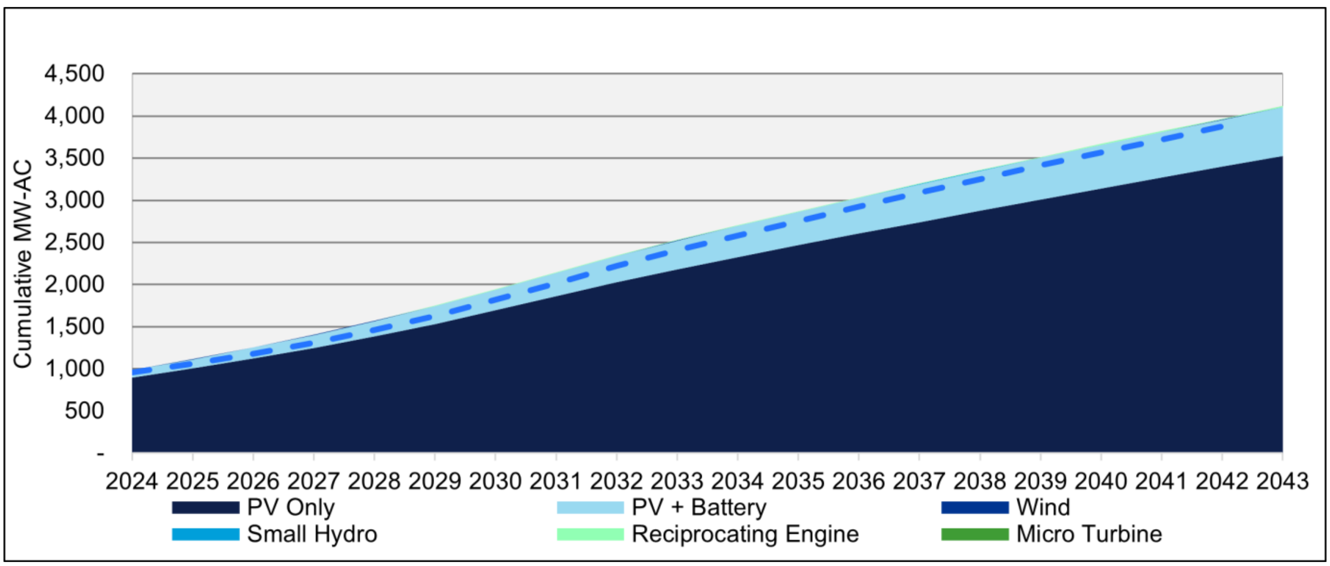
Figure 1-4 shows the base case forecast by state, compared to the previous (2022) assessment's total base case forecast. This figure indicates that Utah and Oregon will drive most PG installations over the next two decades, which is to be expected given these two states represent the largest share of 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.

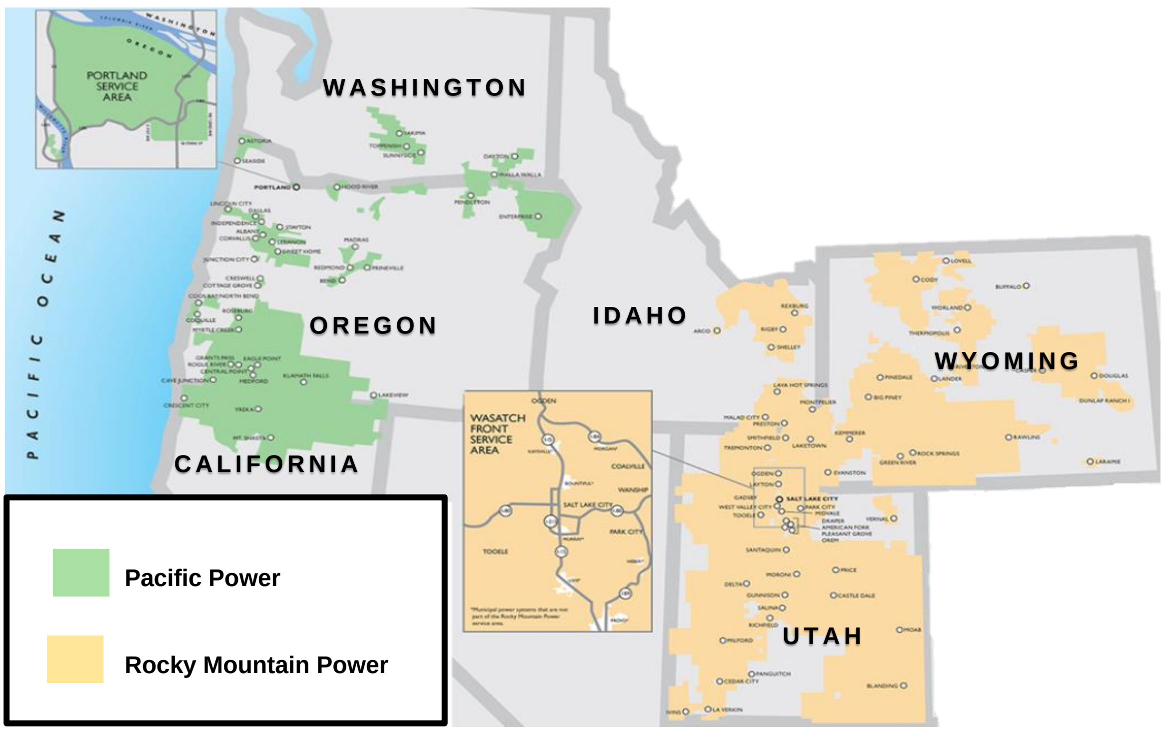
Figure 1-5. Cumulative new capacity installed by technology (MW-AC), 2024-2043, base case



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

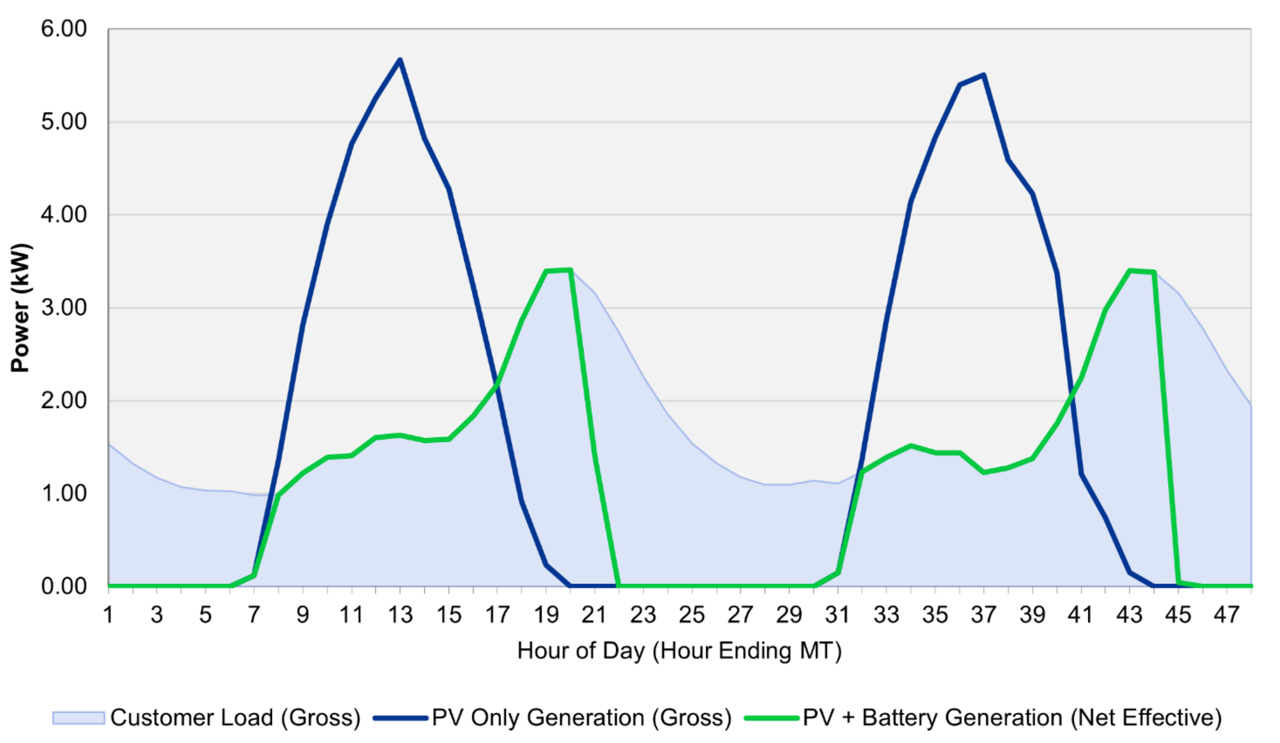
Solar photovoltaic (PV) systems convert sunlight into electrical energy. DNV modeled representative PV system energy output for residential and non-residential systems in each state to estimate first-year production. To model hourly production, DNV leveraged its SolarFarmer and Solar Resource Compass 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.

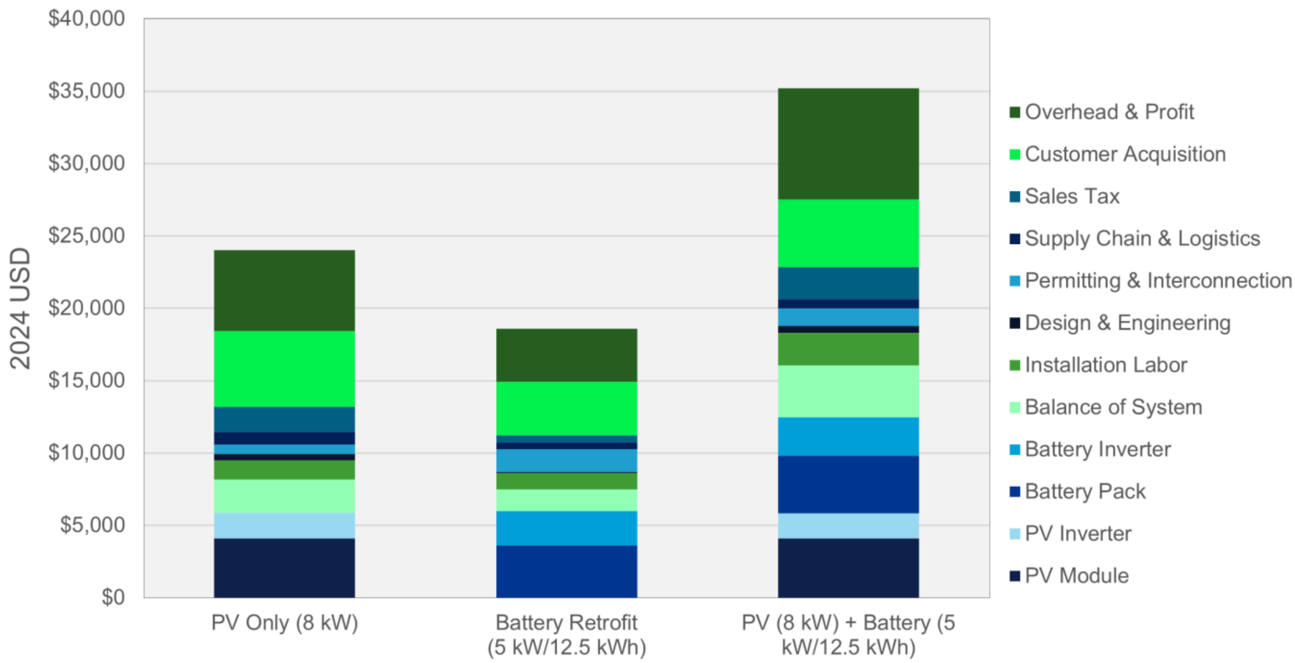
Both cycling and calendar effects were considered in the degradation assessment. It is also assumed the battery cell temperature will be controlled to be around 25°C for the majority of the time with proper thermal management (e.g., ventilation, HVAC). DNV notes that temperature plays a key role in battery 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.

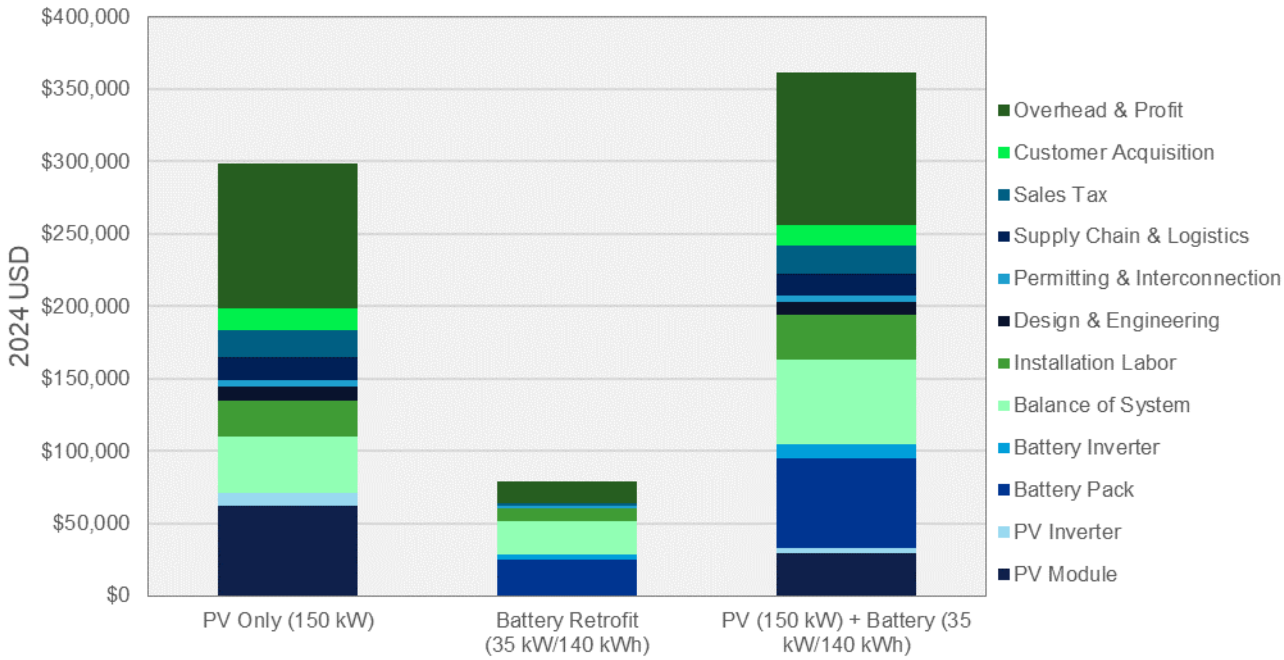
Total installed costs (or capital expenditures) are based on cost assumptions developed on a bottom-up basis—including hardware, installation/interconnection, as well as a provision for sales, general, and administrative costs, and overhead. Capital expenditures (Cap-Ex) are expenditures required to 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

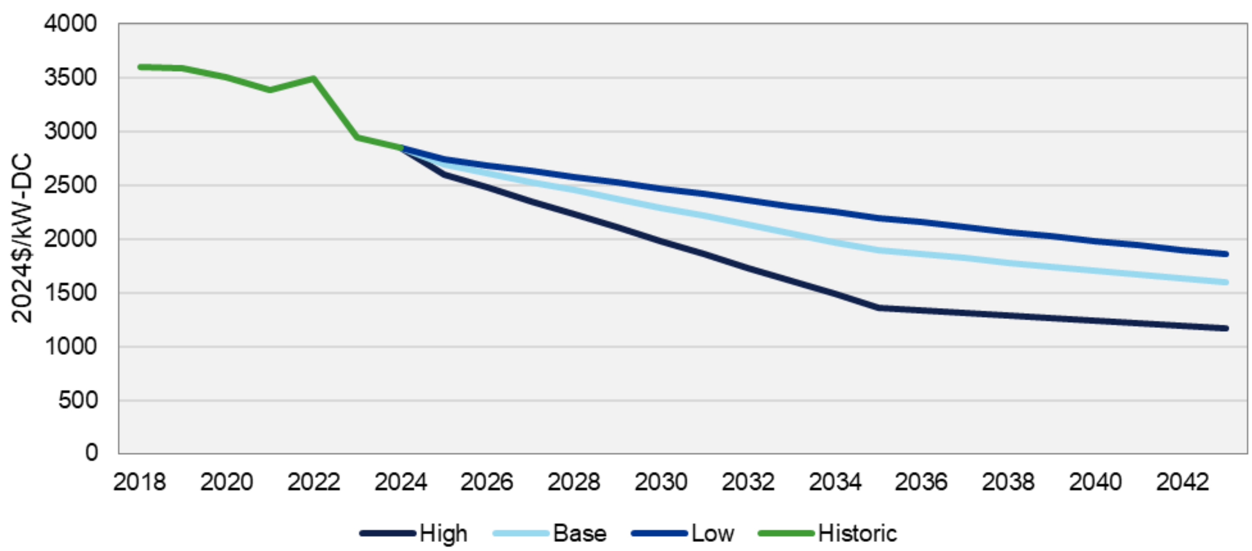


Figure 3-5. Average non-residential solar PV system costs, 2023-2043

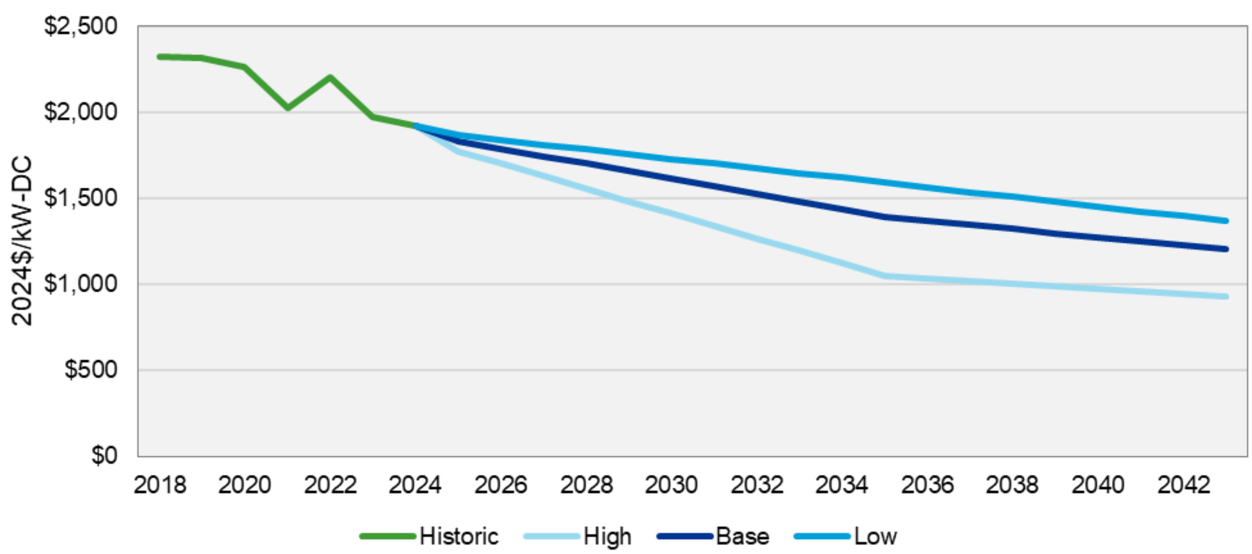


Figure 3-6. Average residential battery energy storage system (AC-coupled) costs, 2024-2043

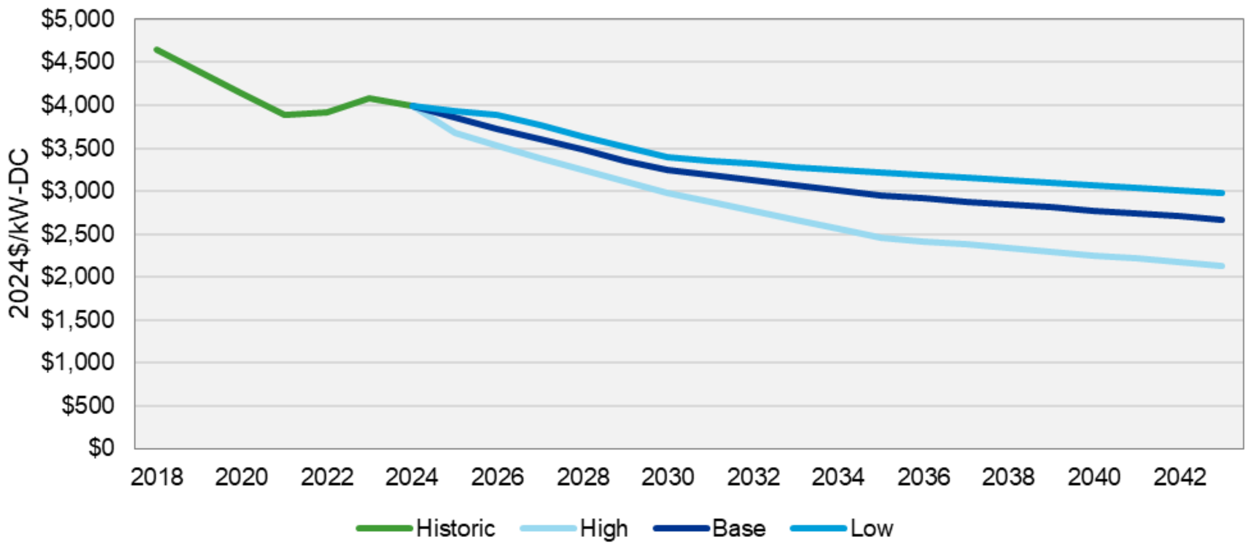
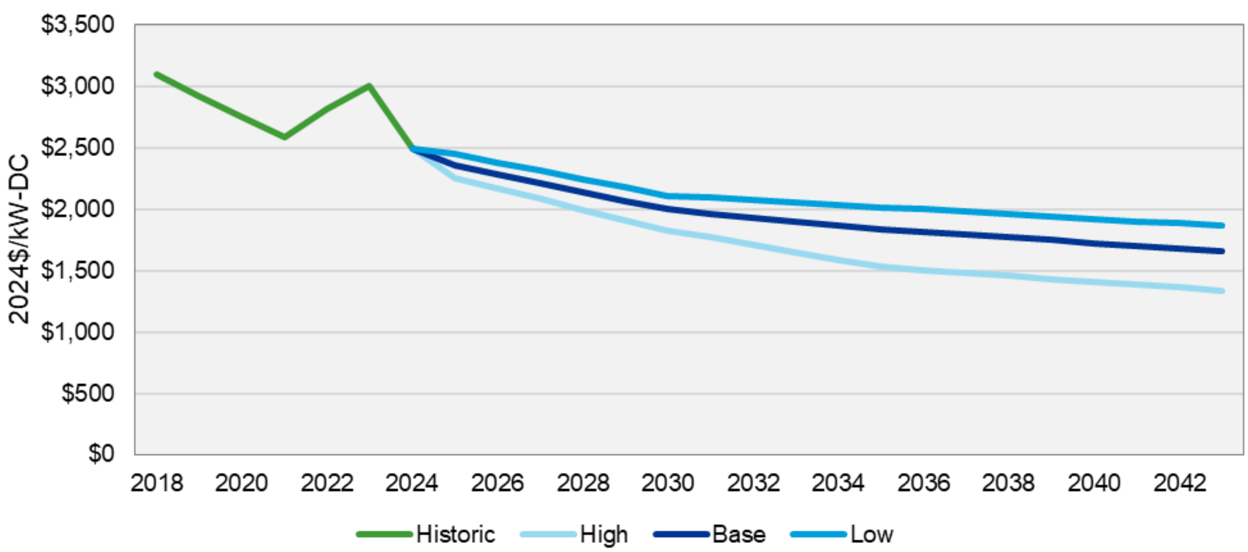


Figure 3-7. Average non-residential battery energy storage system (AC-coupled) costs, 2024-2043



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.

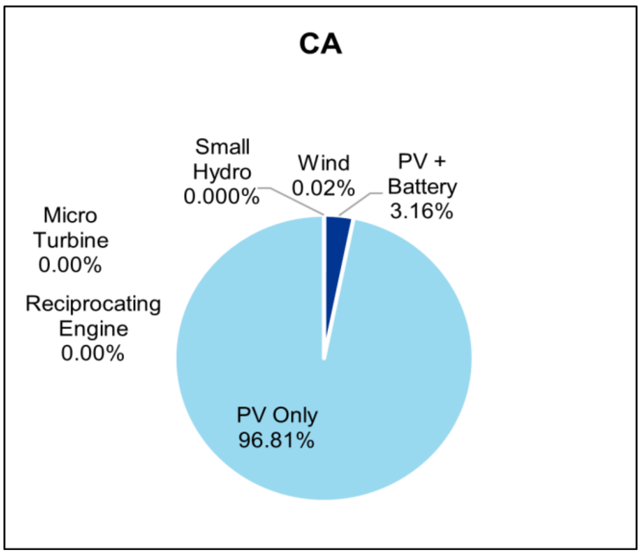
[8] Incentives are provided through the Utah Office of Energy Development Renewable Energy Systems Tax Credit. https://energy.utah.gov/tax-credits/renewable-energy-systems-tax-credit/

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

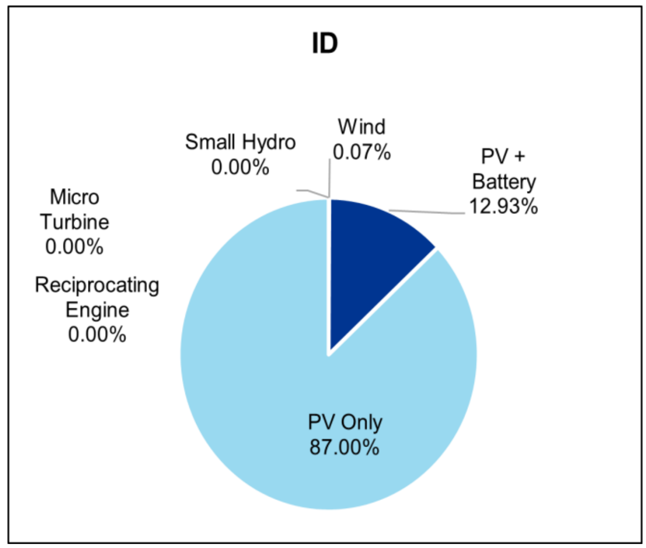
3.2 Current distributed generation market

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.

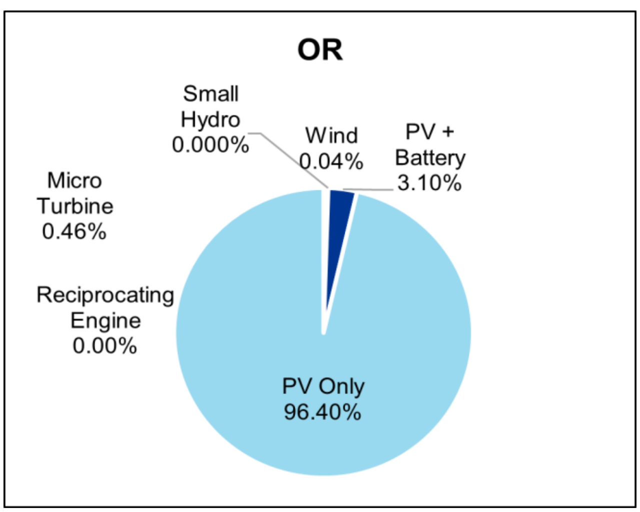
Figure 3-8. Cumulative installed distributed generation capacity by state, by technology, as of March 31, 2024



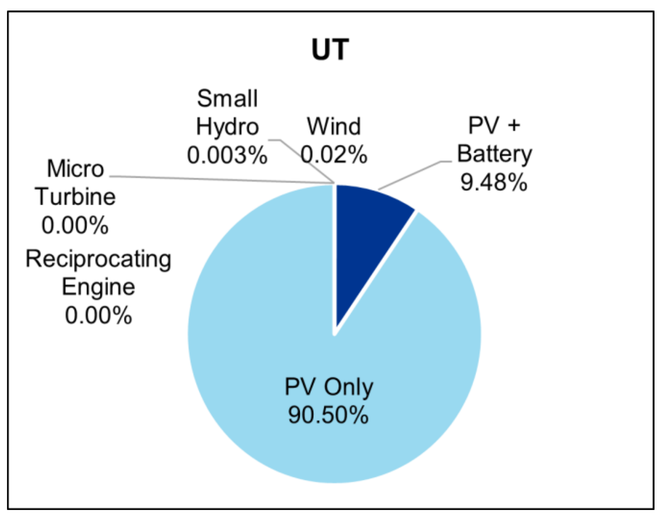
PG capacity installed: 15.8 MW-AC



PG capacity installed: 23.6 MW-AC

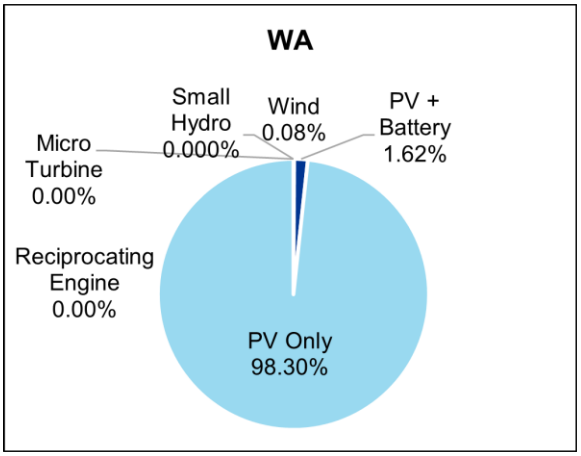


PG capacity installed: 190.1 MW-AC

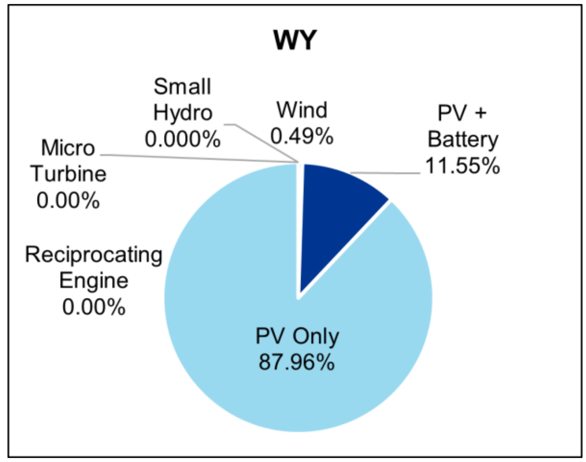


PG capacity installed: 593.5 MW-AC

[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.

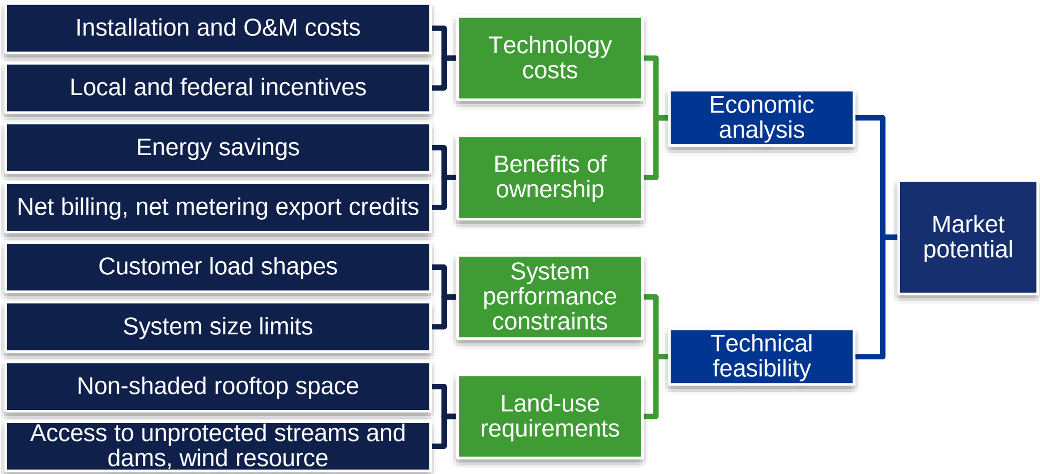


Figure 3-9. Methodology to determine market potential of distributed generation adoption

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 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]

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

Where:

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.

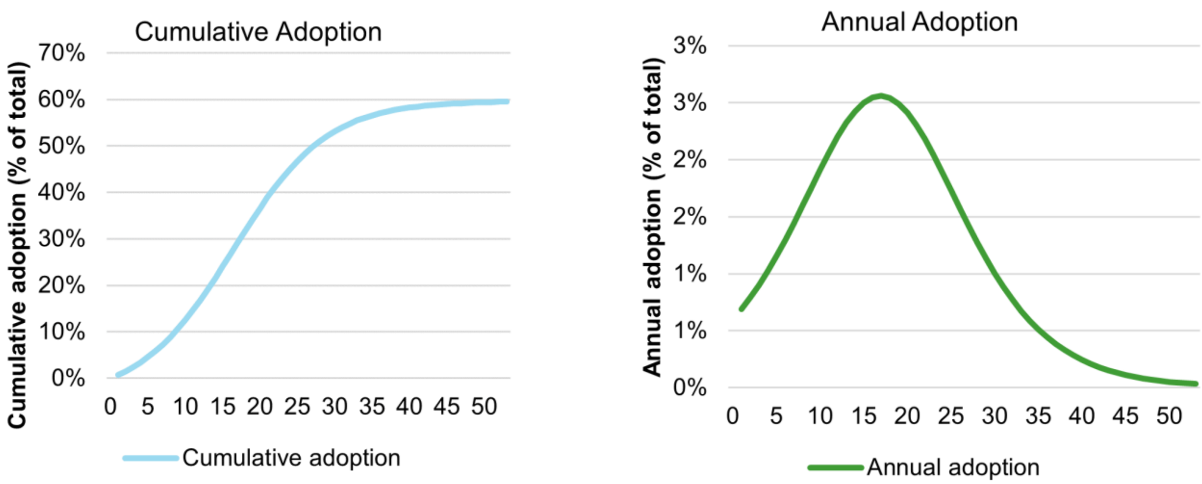
[11] Kao, Shih-Chieh, Mcmanamay, Ryan A., Stewart, Kevin M., Samu, Nicole M., Hadjerioua, Boualem, Deneale, Scott T., Yeasmin, Dilruba, Pasha, M. Fayzul K., Oubeidillah, Abdoul A., and Smith, Brennan T. New Stream-reach Development: A Comprehensive Assessment of Hydropower Energy Potential in the United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

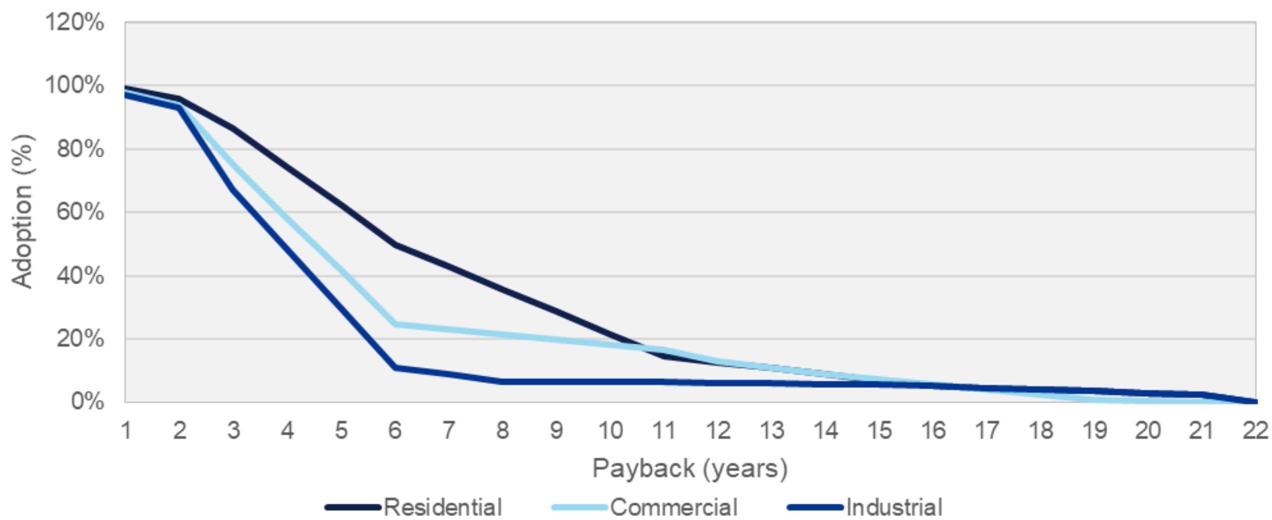
Table 3-11. Solar willingness-to-adopt curve used by state and sector

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

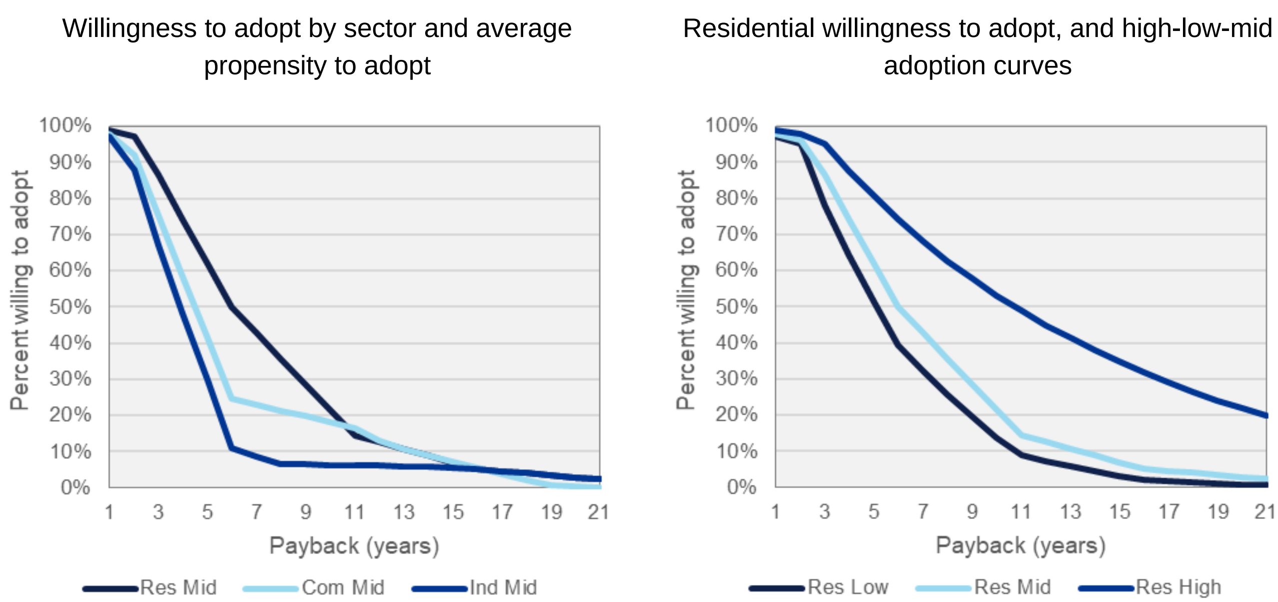
Figure 3-11 shows the willingness-to-adopt curves for residential, commercial, and industrial sectors assuming an average propensity to adopt (the “Mid” case). There was too little irrigation adoption to assess the sector independently, so we used the commercial curves for the irrigation sector.

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.

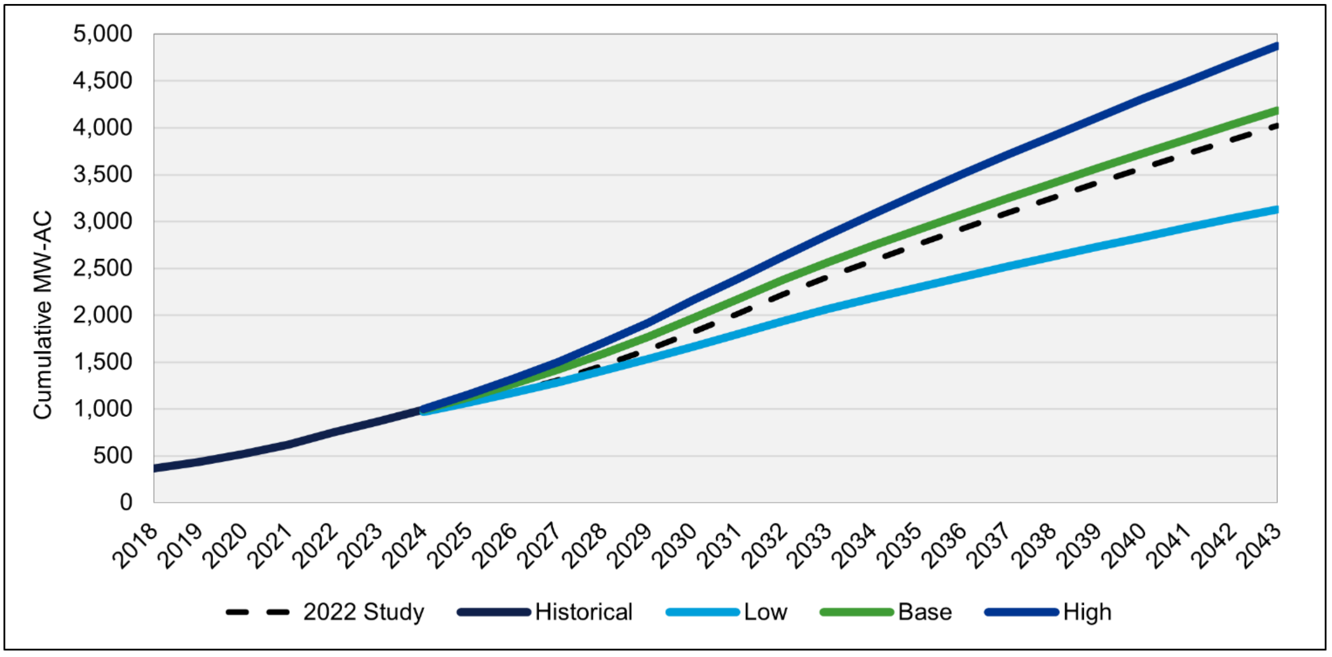
4 RESULTS

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

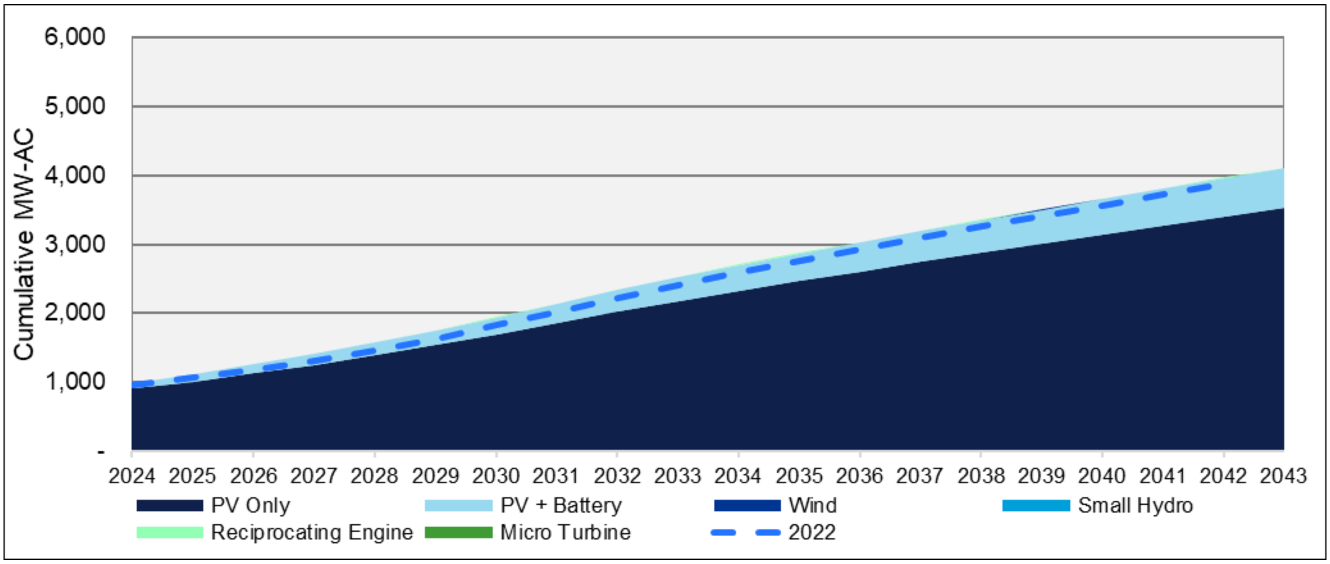


Figure 4-3. Cumulative new capacity installed by technology (MW-AC), 2024-2043, low case

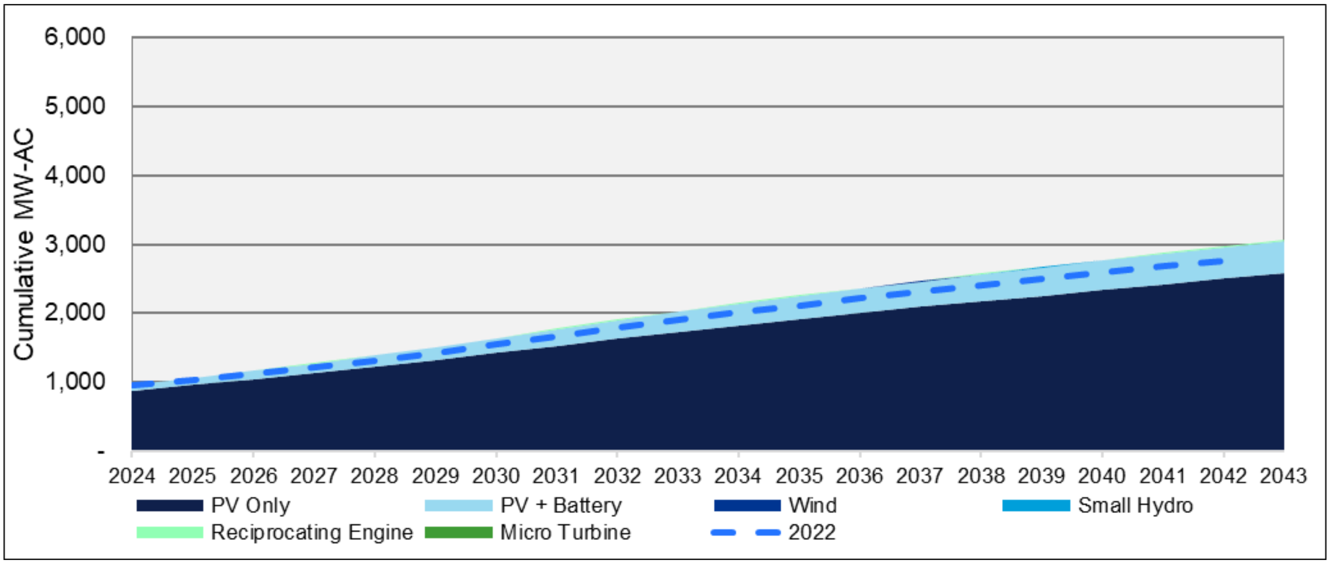
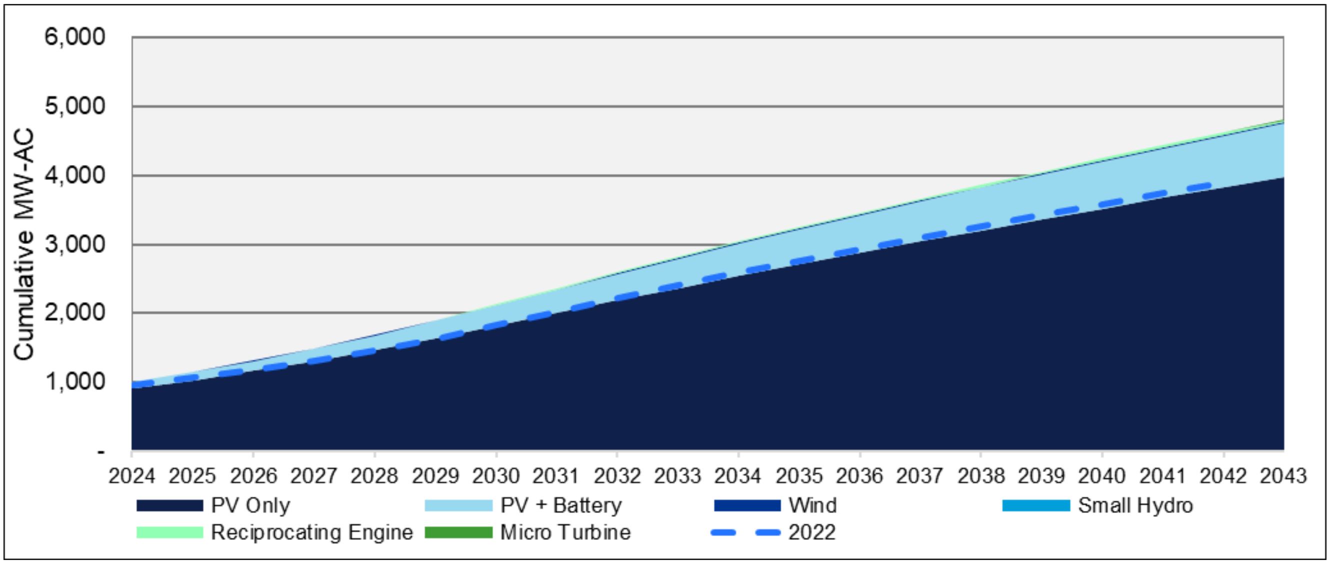


Figure 4-4. Cumulative new capacity installed by technology (MW-AC), 2024-2043, high case



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)

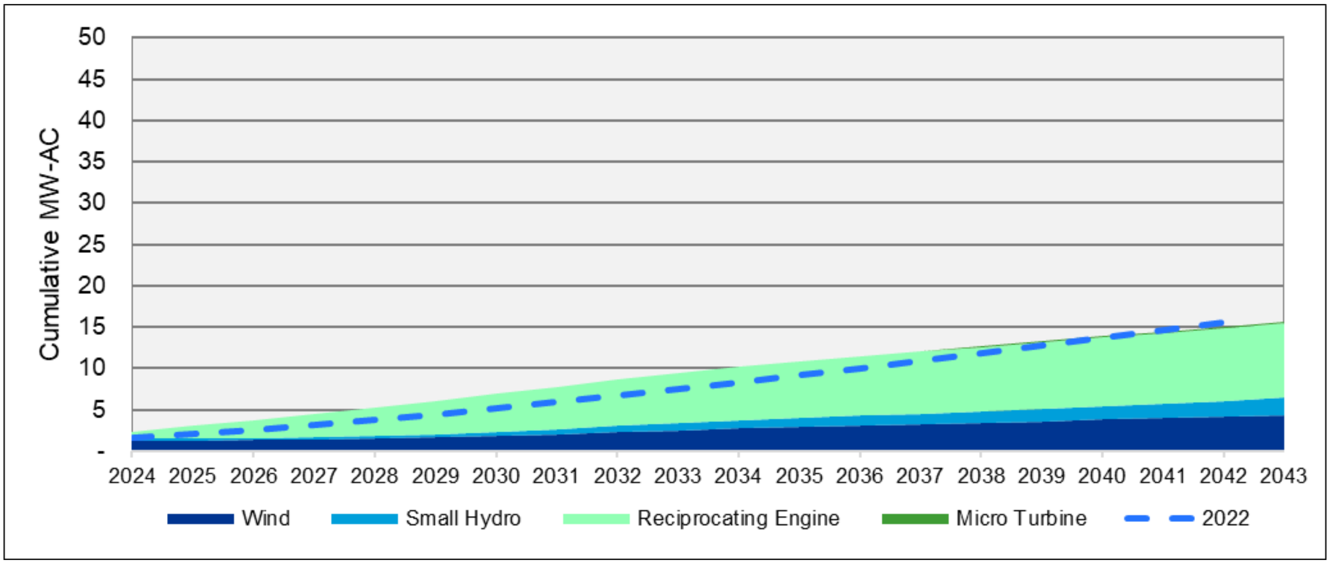


Figure 4-6. Cumulative new capacity installed by technology (MW-AC), 2024-2043, low case (Excluding PV & PV + Battery)

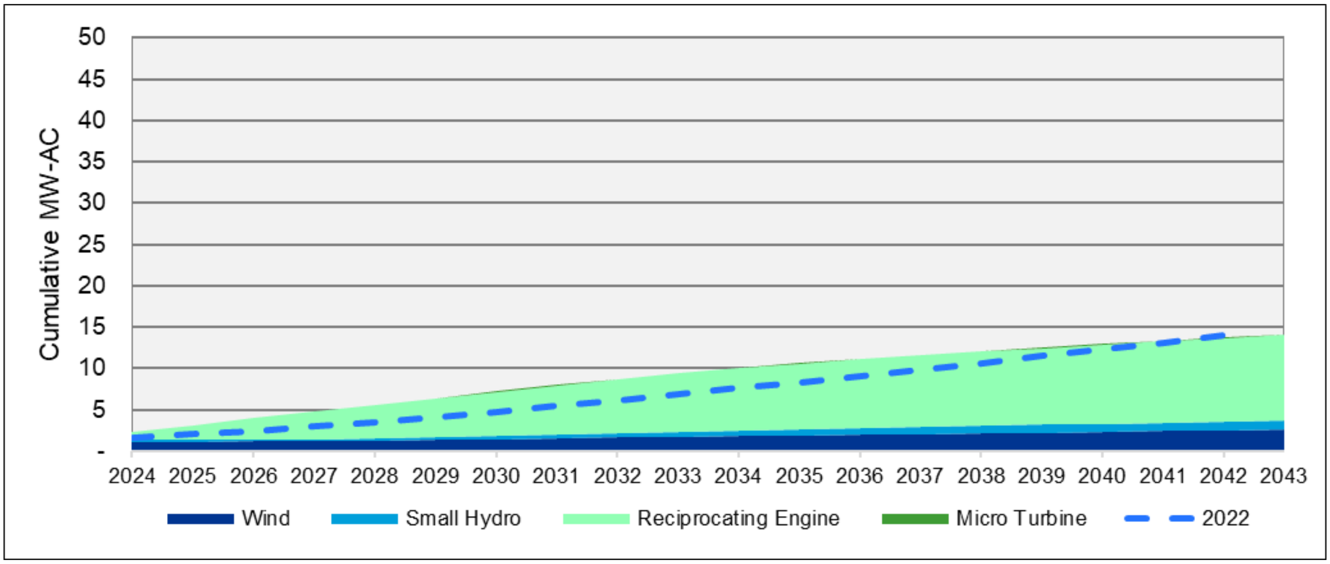
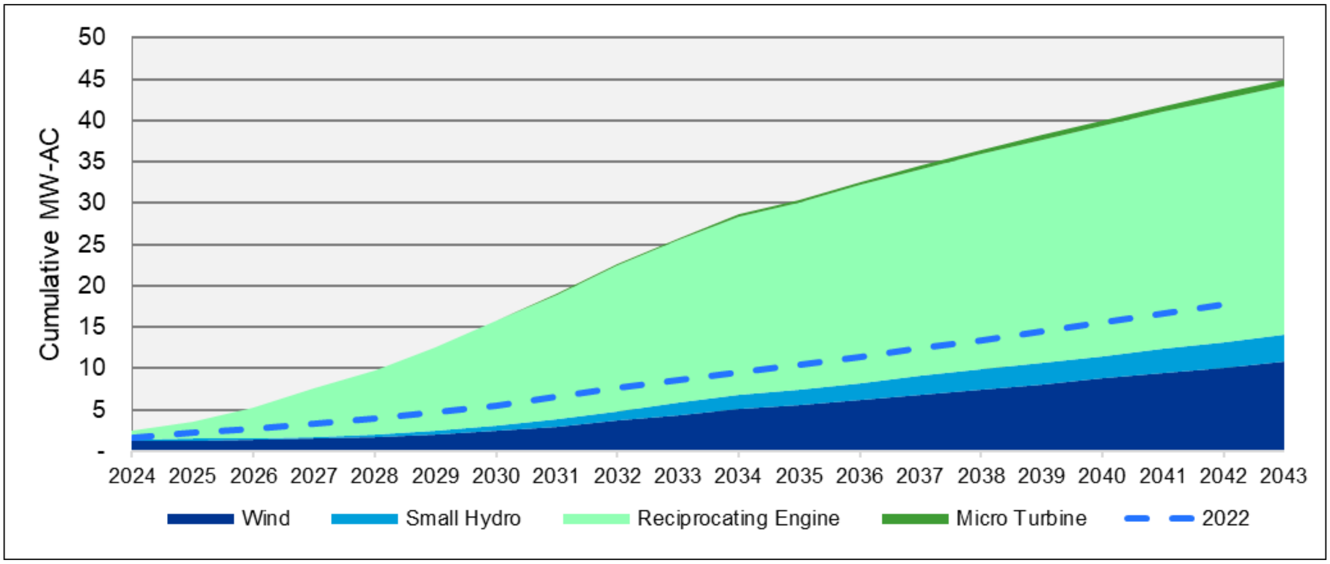


Figure 4-7. Cumulative new capacity installed by technology (MW-AC), 2024-2043, high case (Excluding PV & PV + Battery)

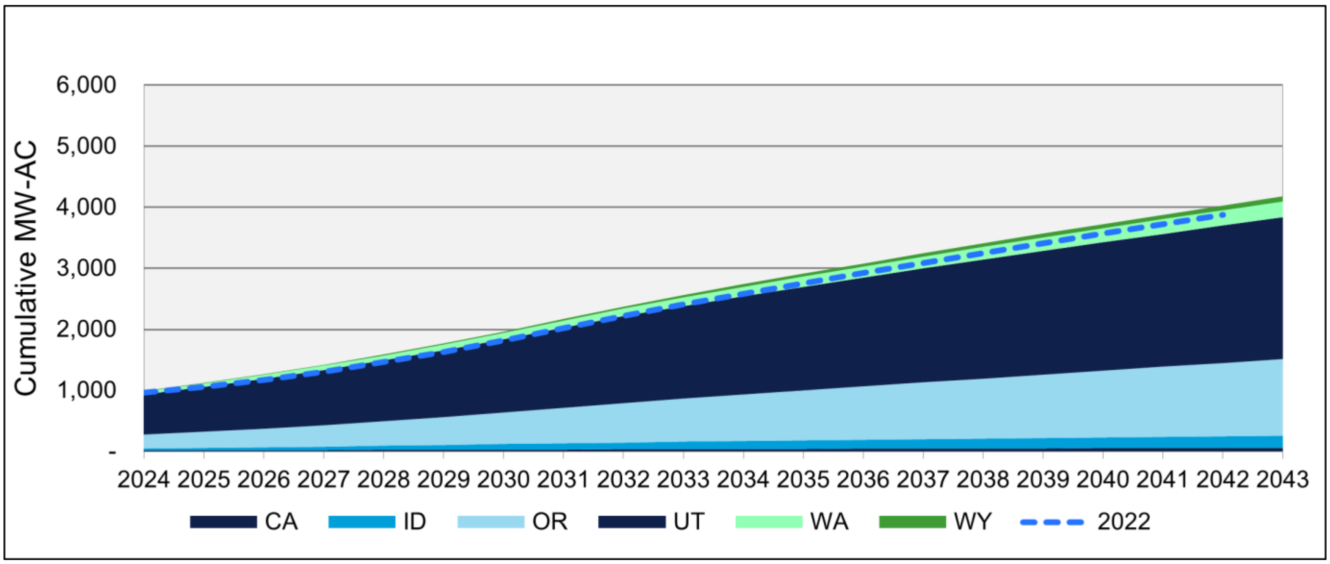


4.1 Generation capacity results by state

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

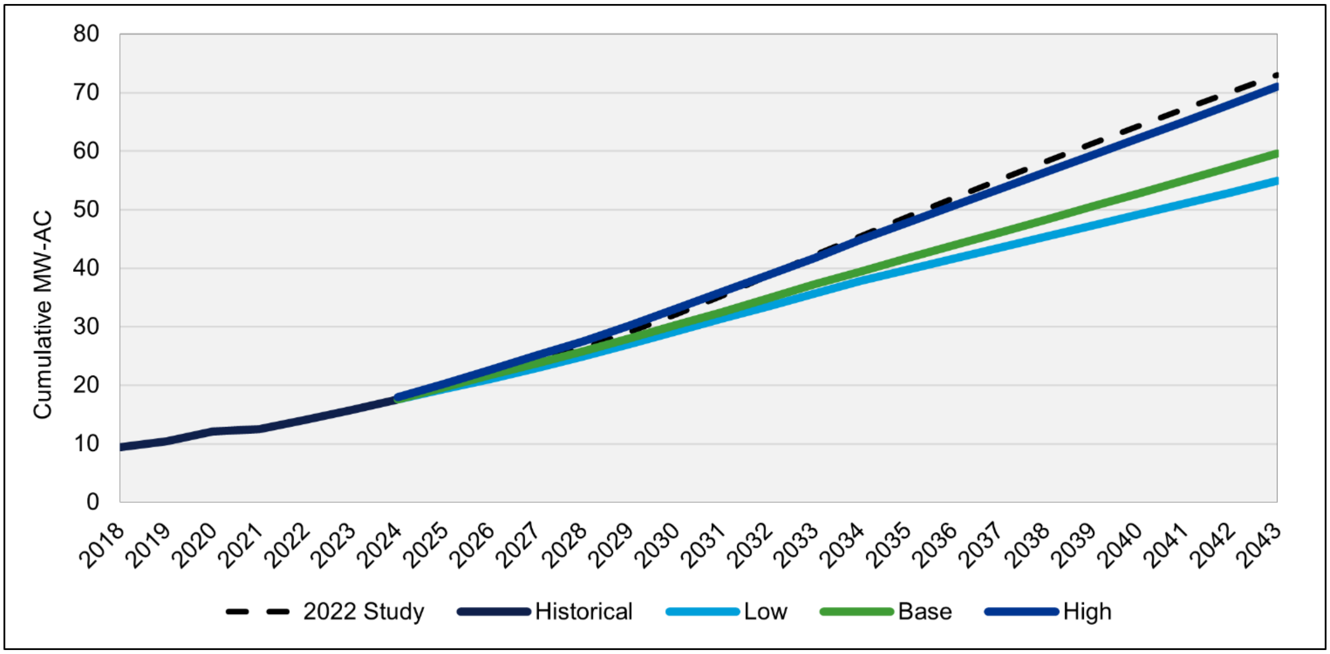


Figure 4-10. Cumulative new capacity installations by technology (MW-AC), California base case, 2024-2043

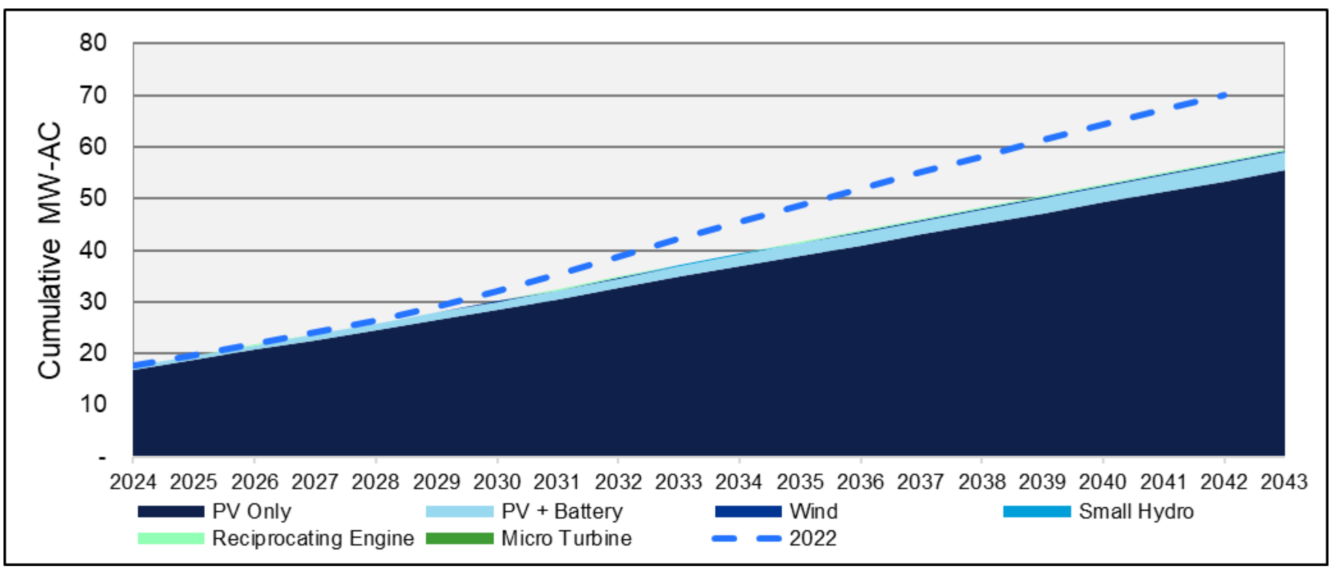


Figure 4-11. Cumulative new capacity installations by technology (MW-AC), California low case, 2024-2043

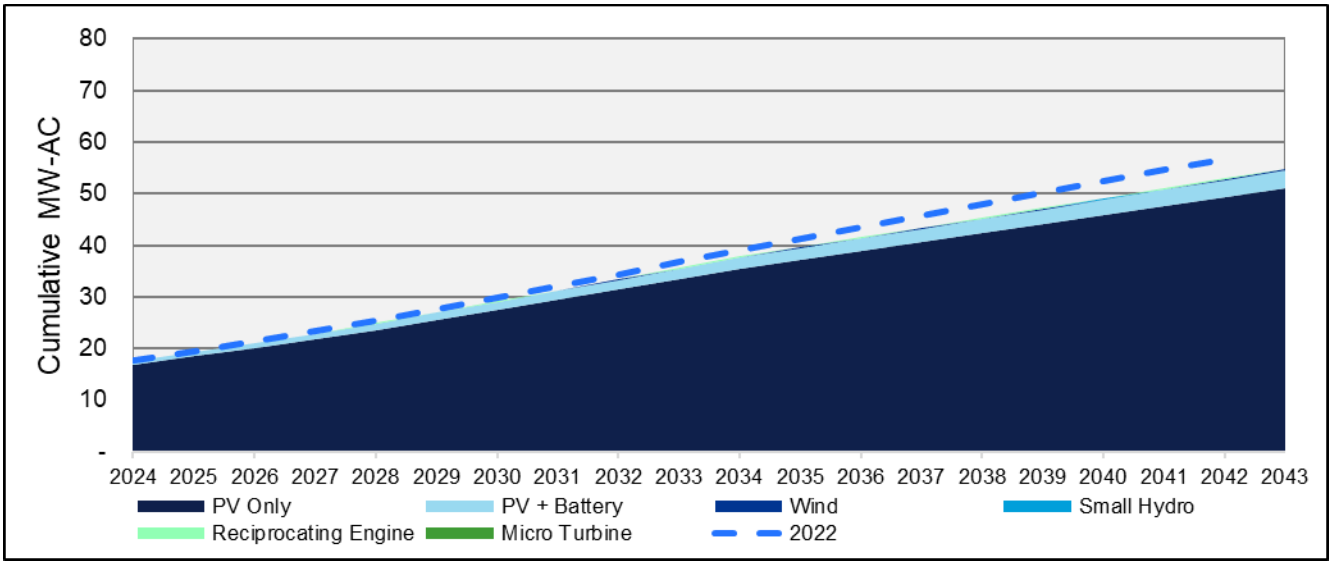
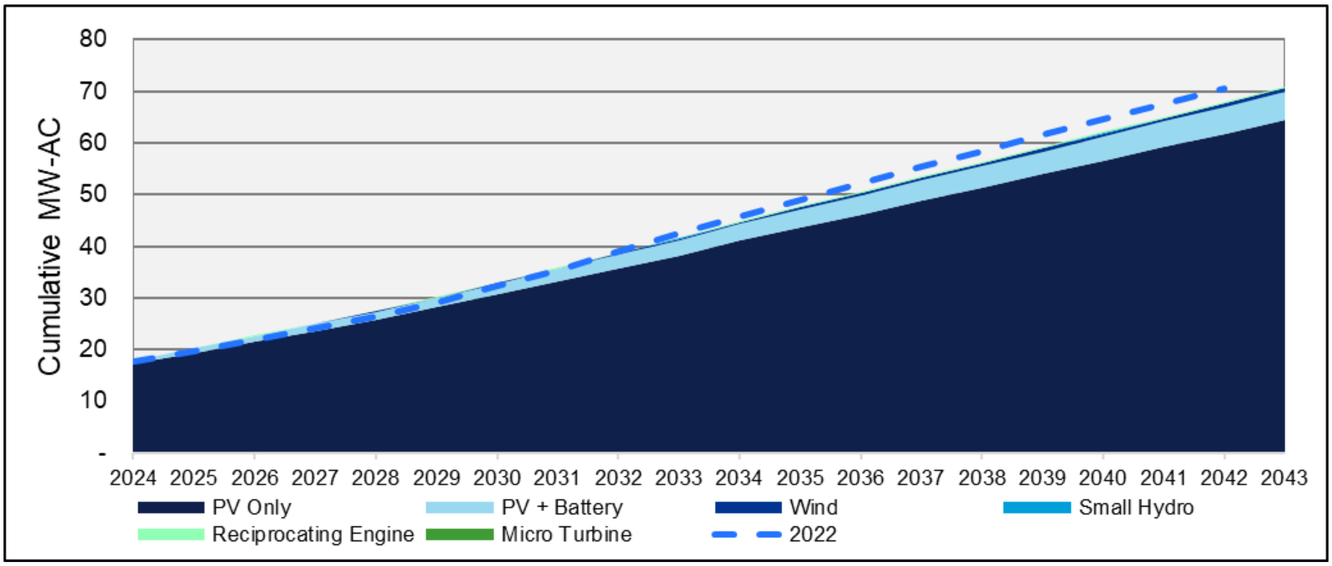


Figure 4-12. Cumulative new capacity installed by technology (MW-AC), California high case, 2024-2043

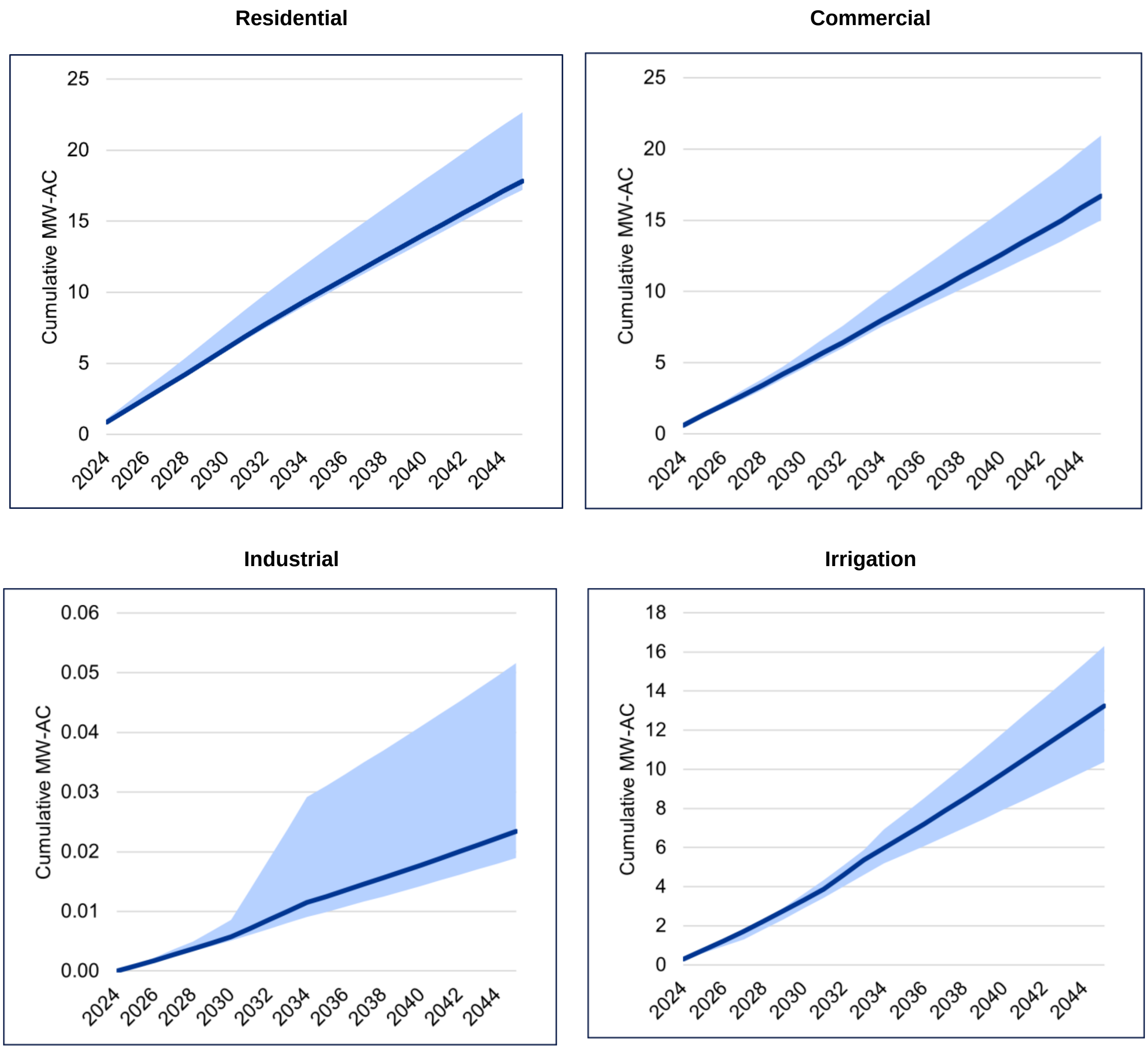


4.1.1.1 California PV adoption by sector

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

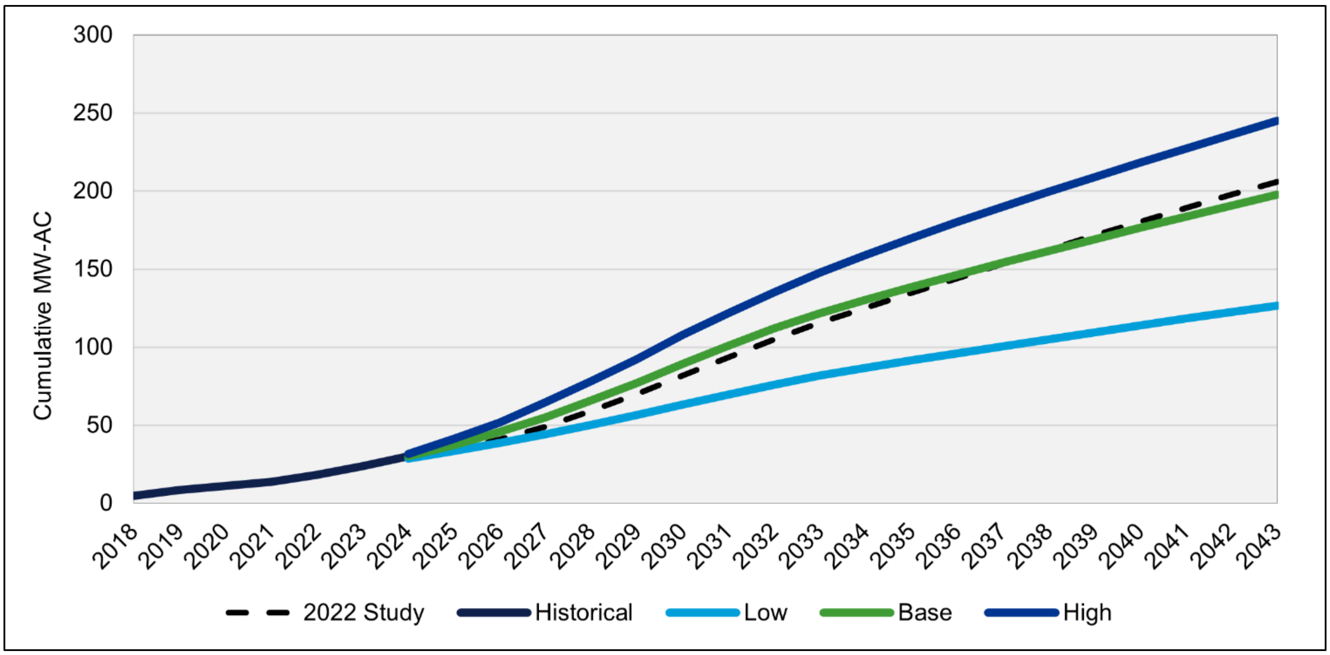


Figure 4-15. Cumulative new capacity installations by technology (MW-AC), Idaho base case, 2024-2043

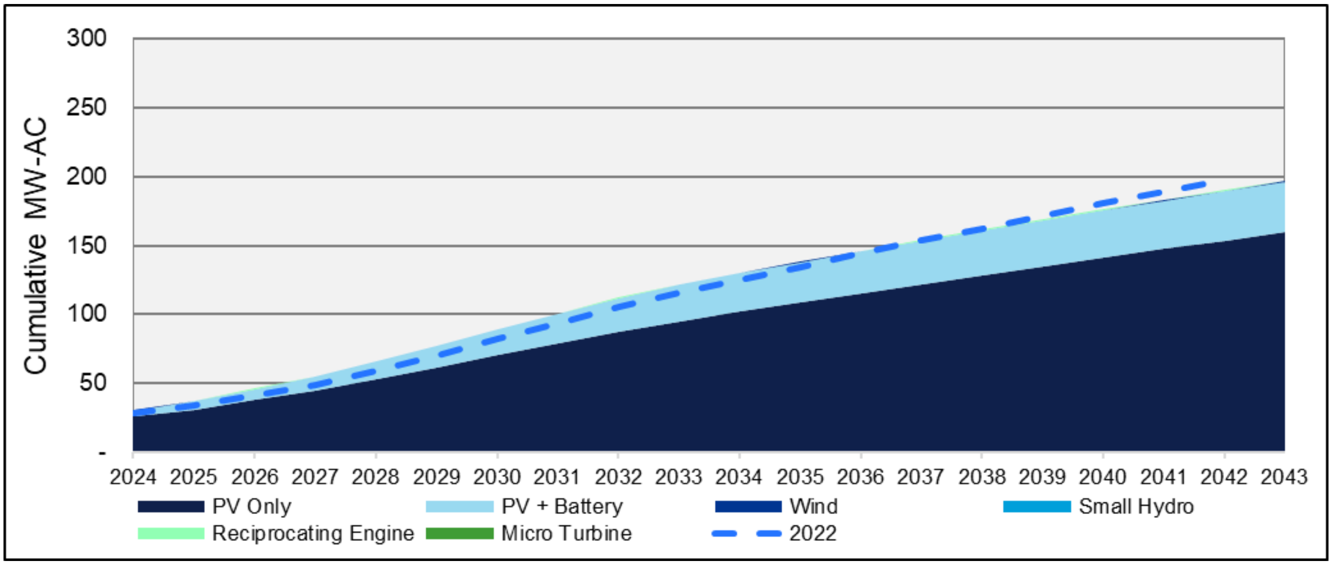


Figure 4-16. Cumulative new capacity installations by technology (MW-AC), Idaho low case, 2024-2043

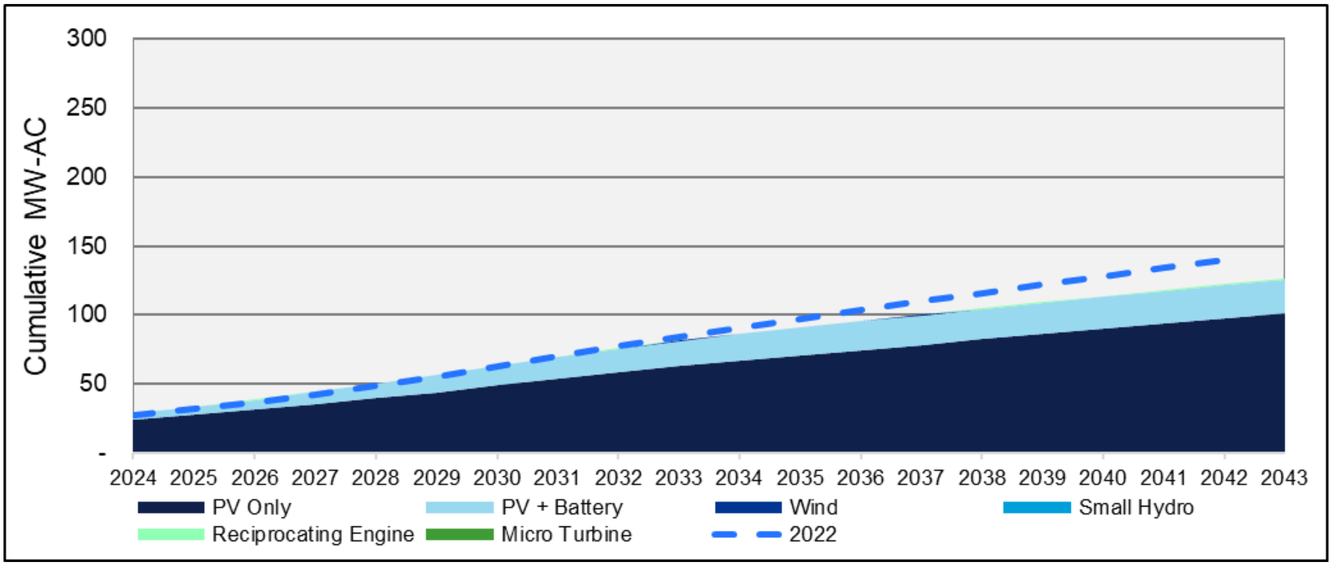
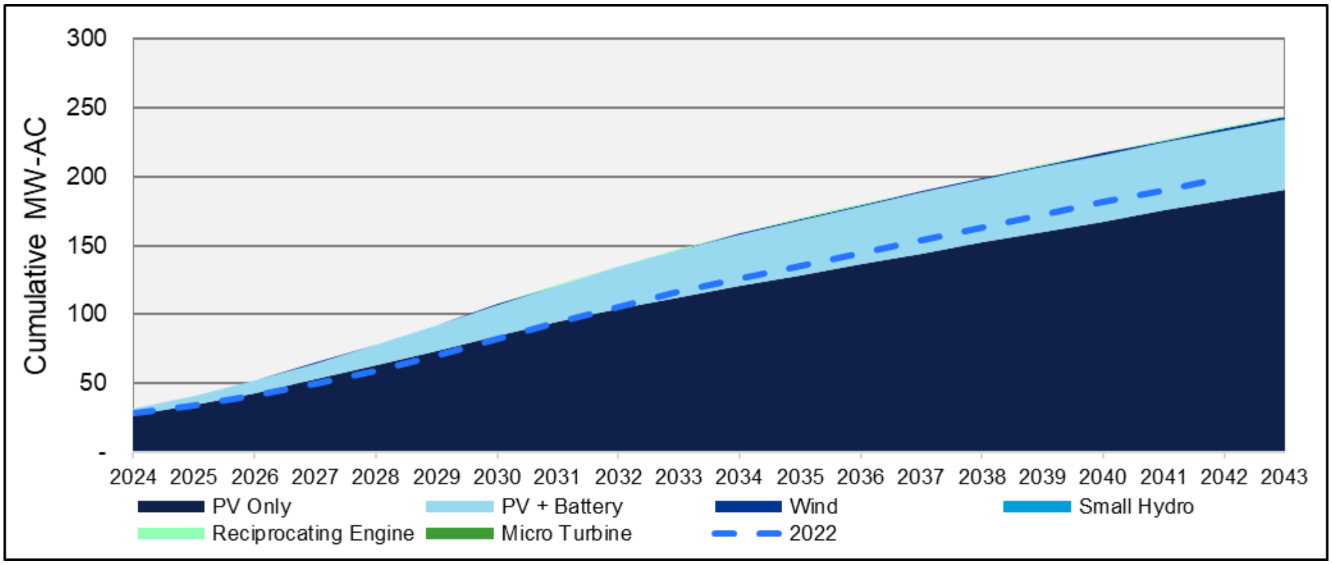


Figure 4-17. Cumulative new capacity installations by technology (MW-AC), Idaho high case, 2024-2043

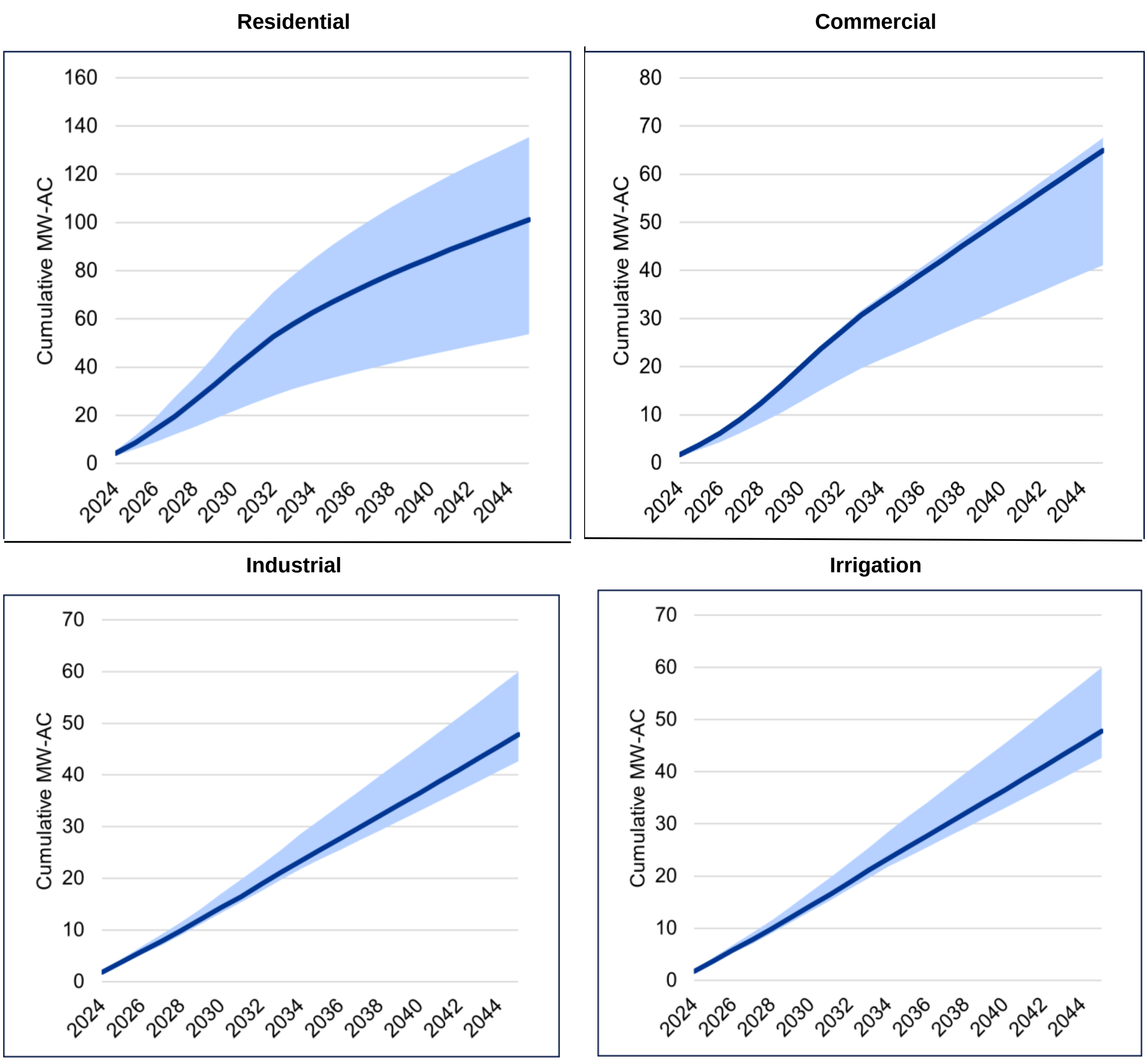


4.1.2.1 Idaho PV adoption by sector

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

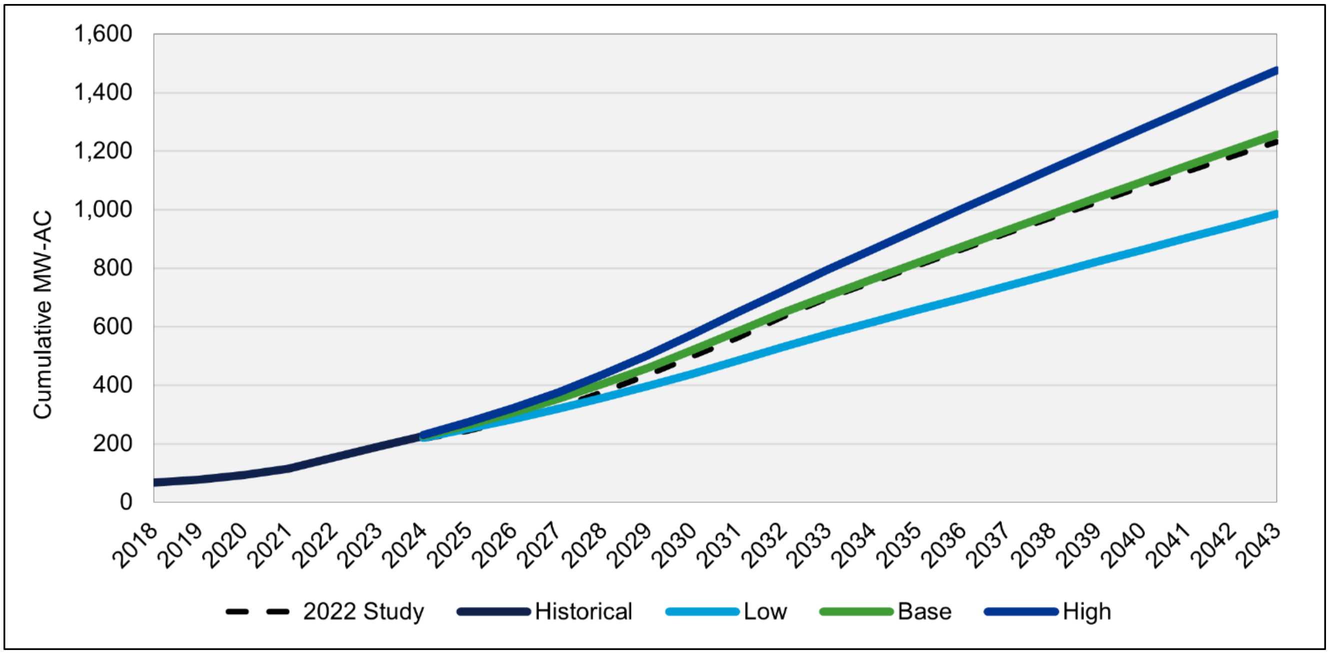


Figure 4-20. Cumulative new capacity installations by technology (MW-AC), Oregon base case, 2024-2043

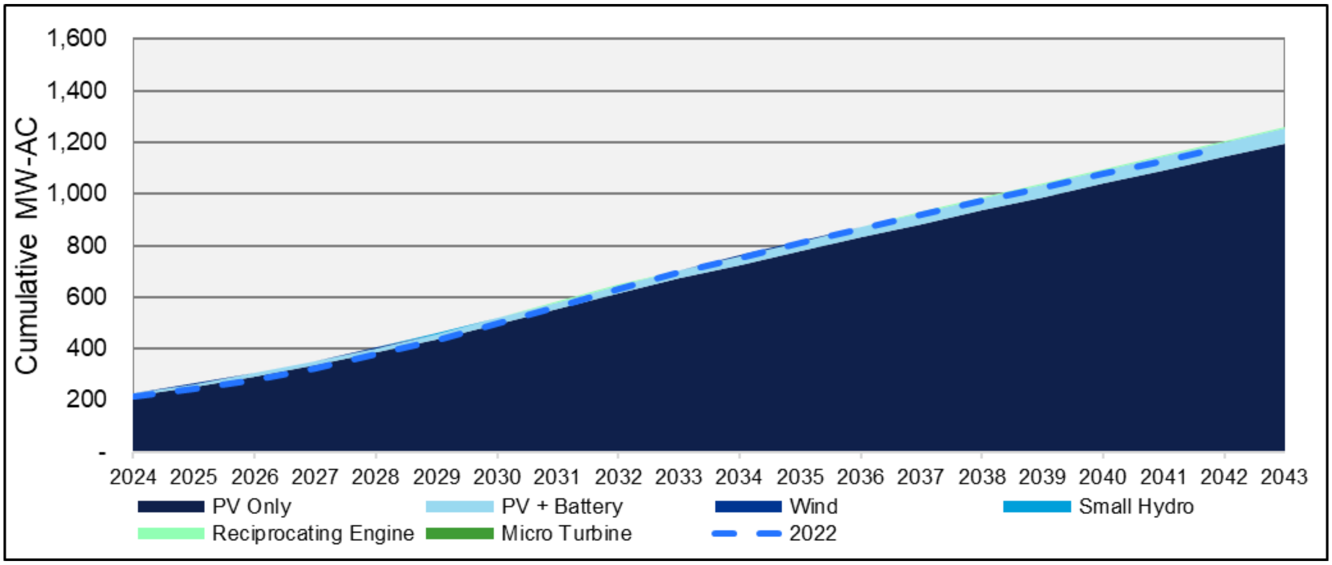


Figure 4-21. Cumulative new capacity installations by technology (MW-AC), Oregon low case, 2024-2043

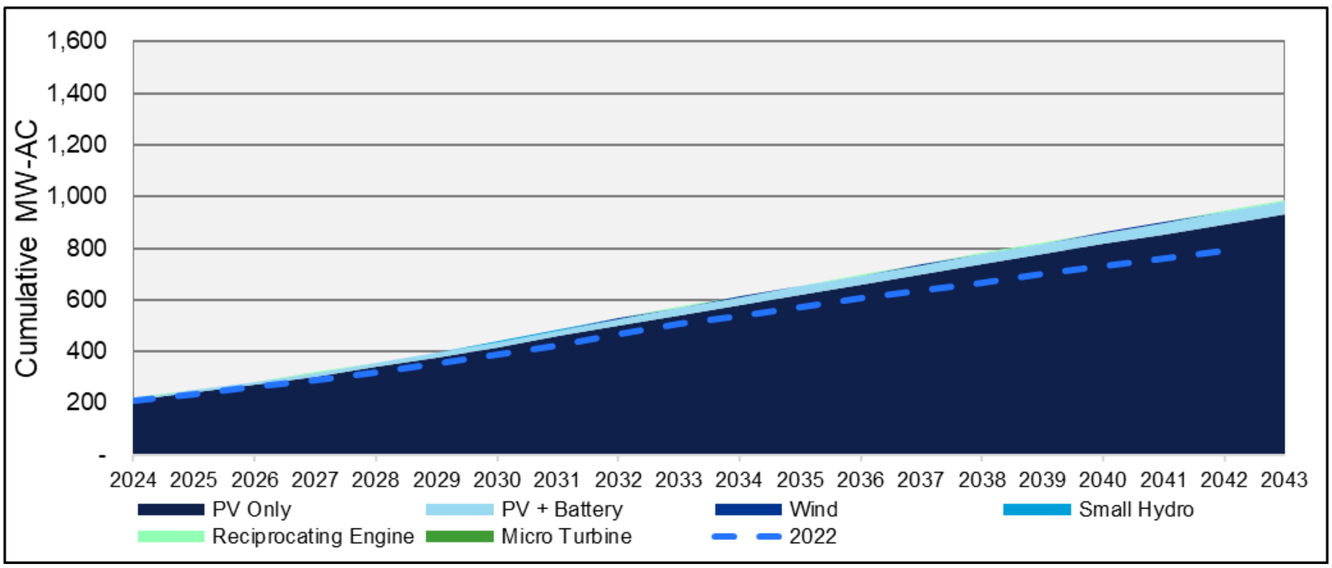
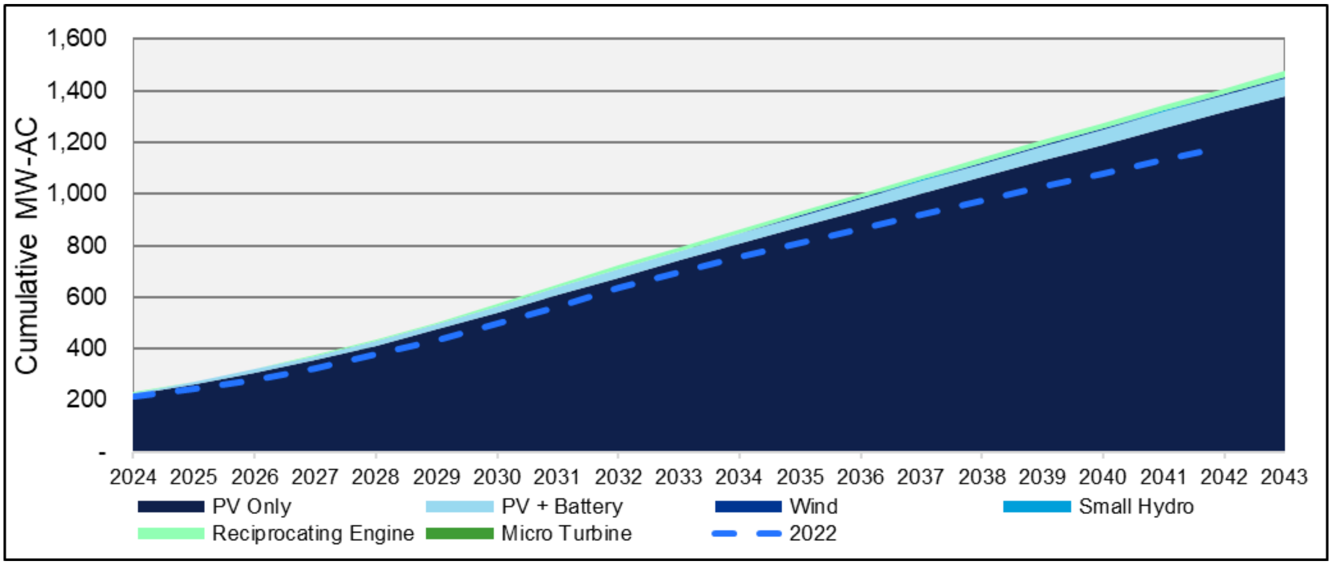


Figure 4-22. Cumulative new capacity installations by technology (MW-AC), Oregon high case, 2024-2043

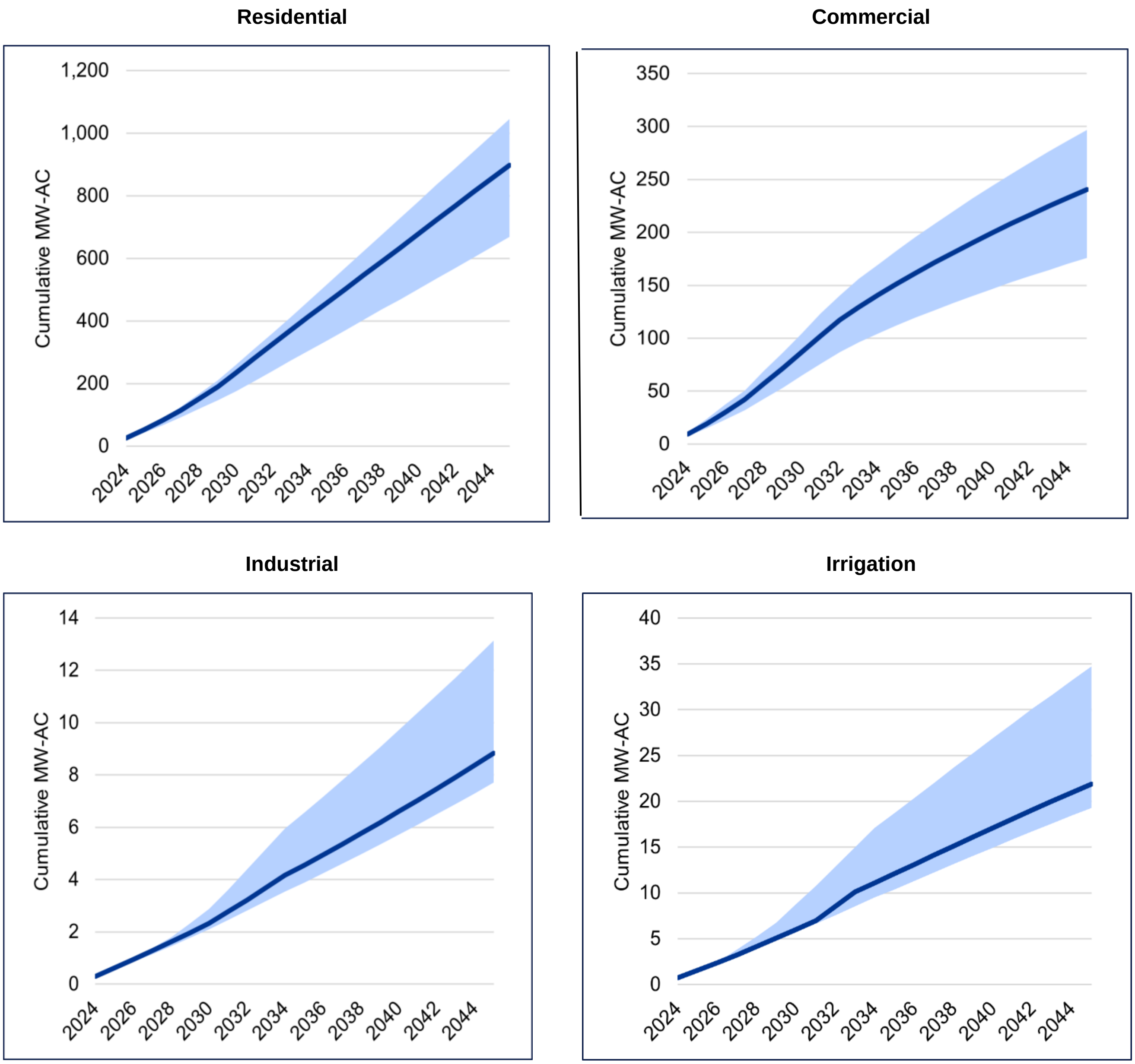


4.1.3.1 Oregon PV adoption by sector

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

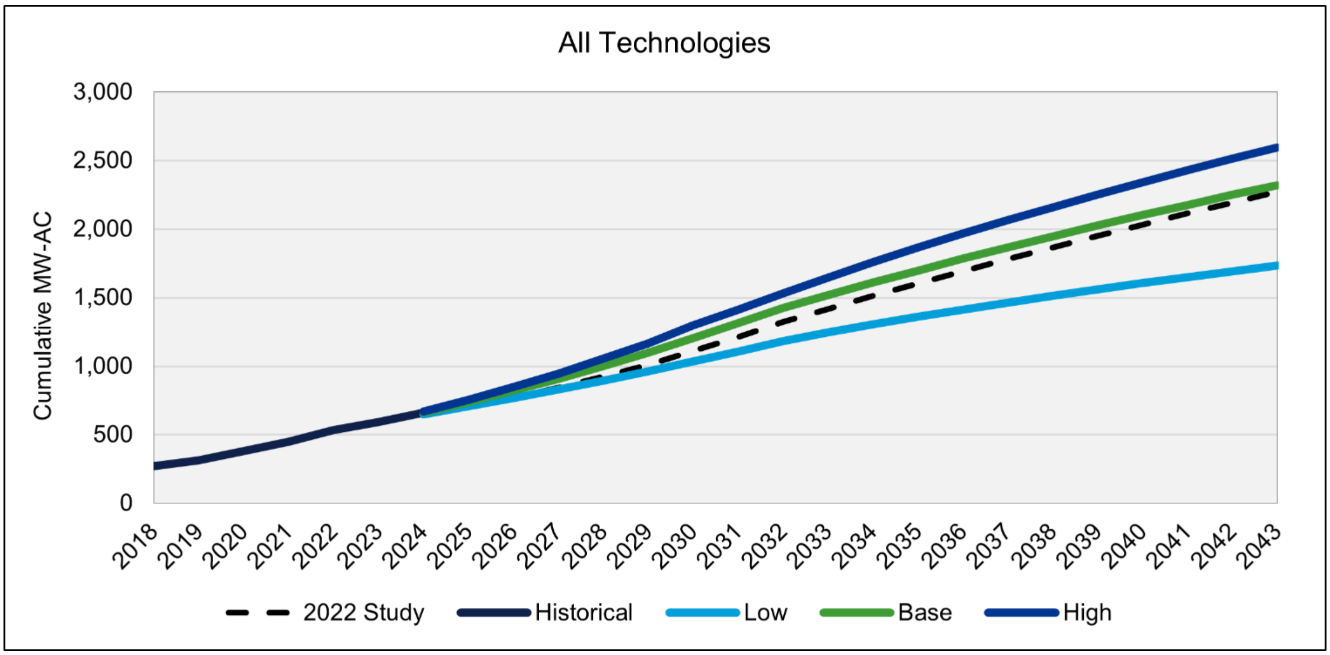


Figure 4-25. Cumulative new capacity installations by technology (MW-AC), Utah base case, 2024-2043

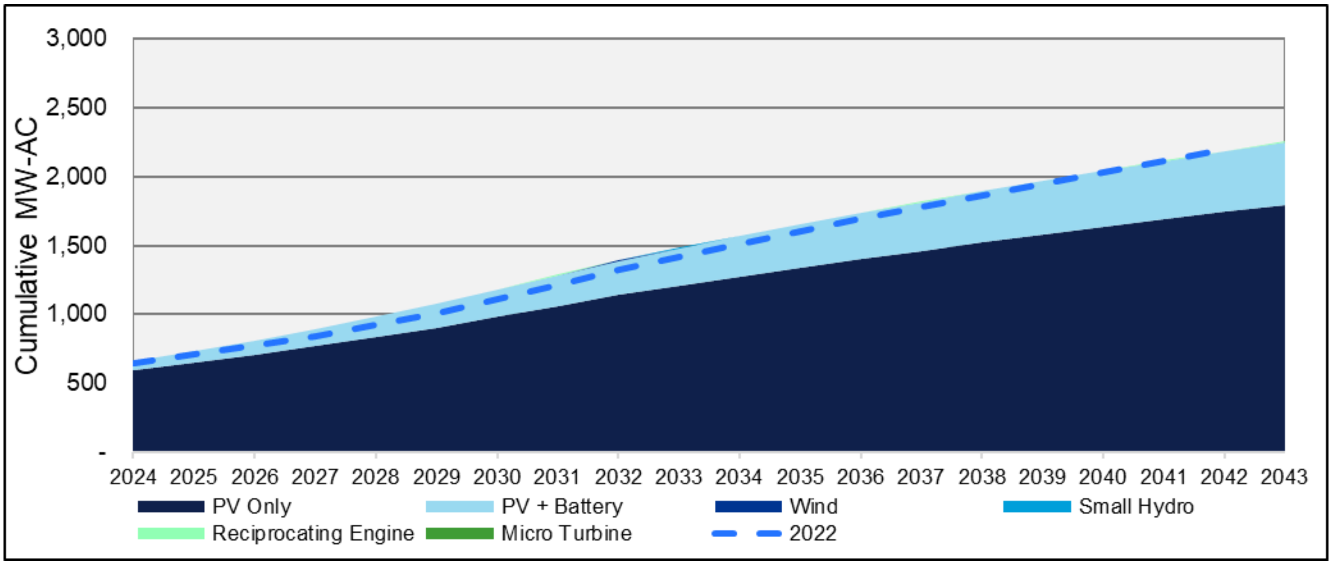


Figure 4-26. Cumulative new capacity installations by technology (MW-AC), Utah low case, 2024-2043

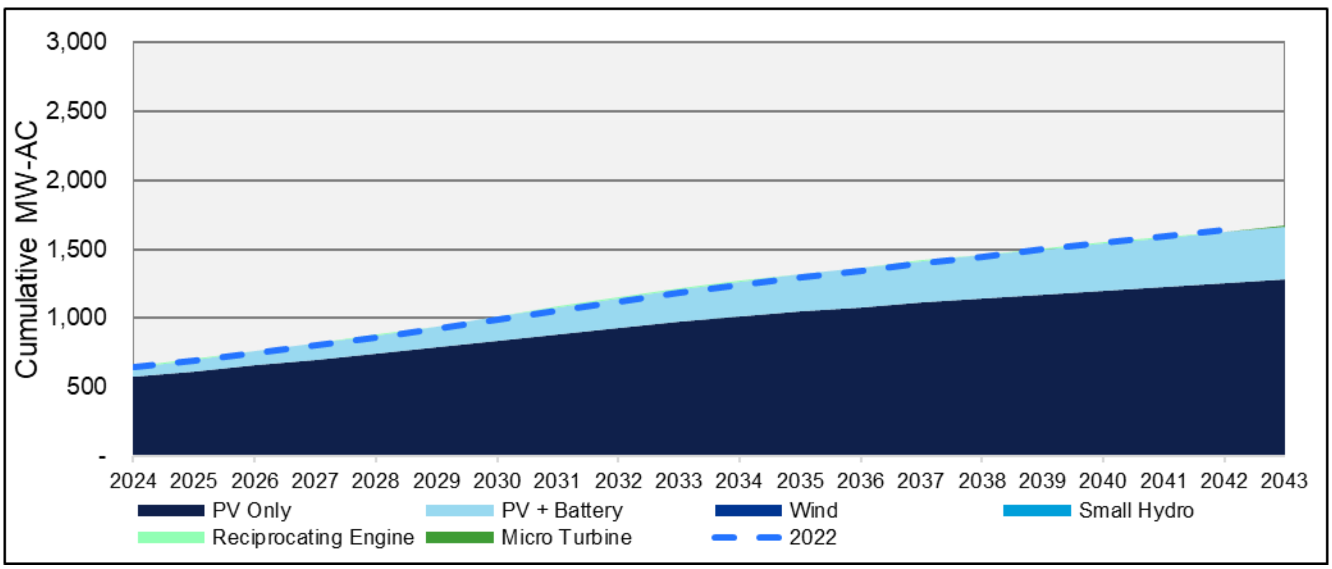
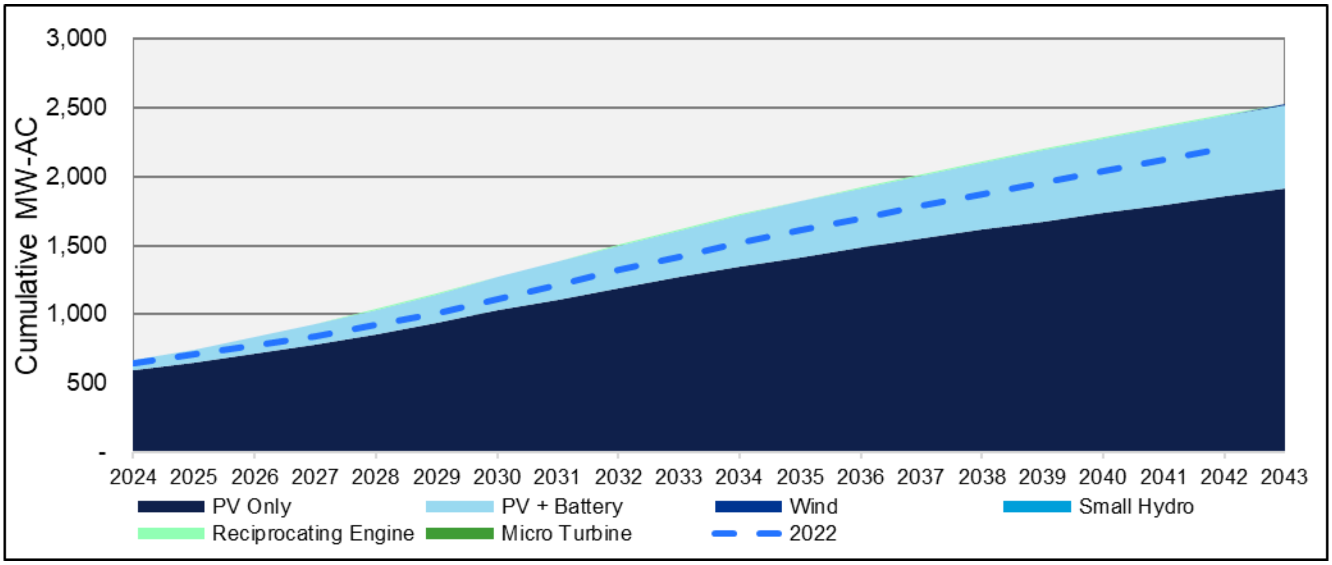


Figure 4-27. Cumulative new capacity installations by technology (MW-AC), Utah high case, 2024-2043

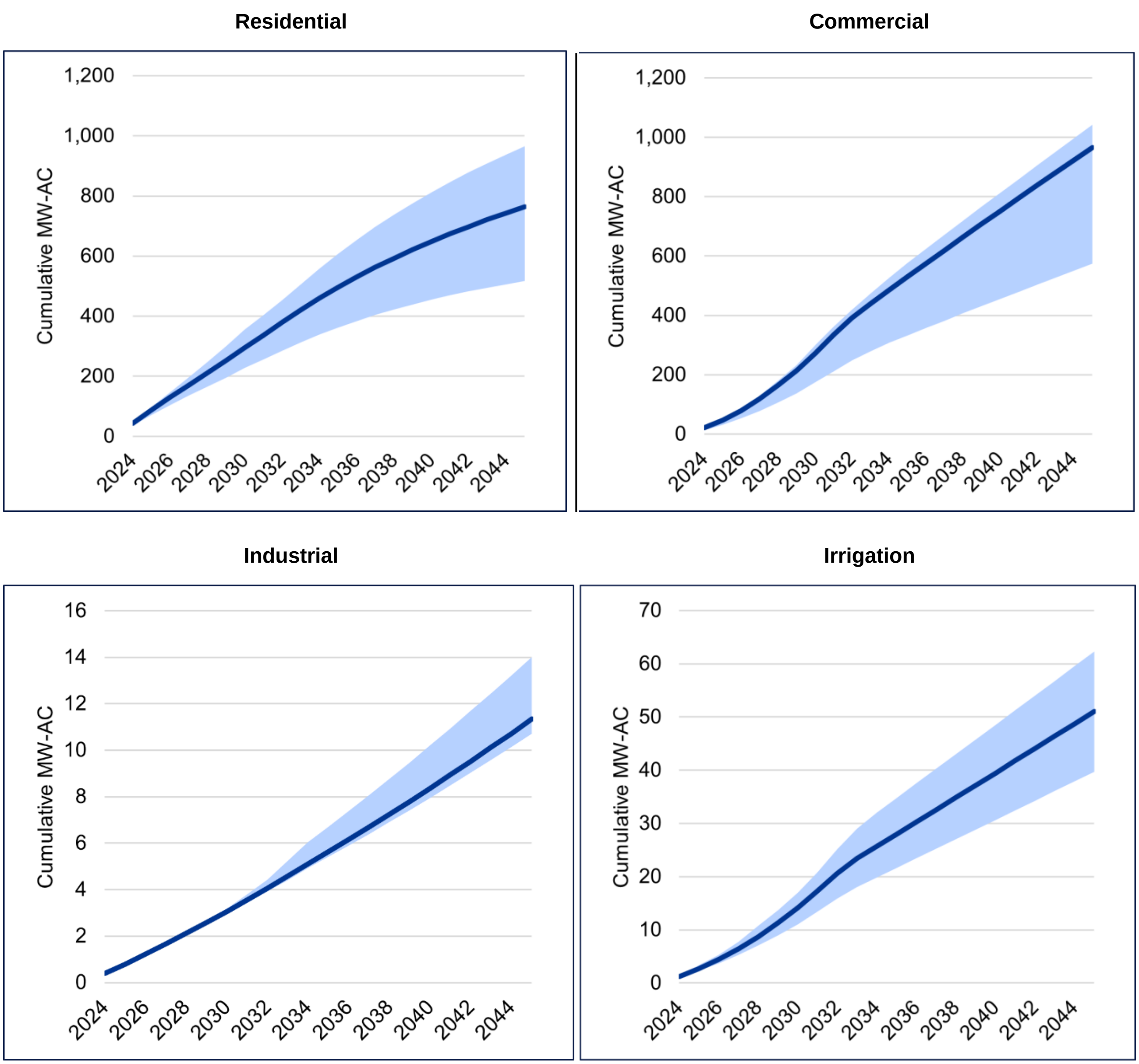


4.1.4.1 Utah PV adoption by sector

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

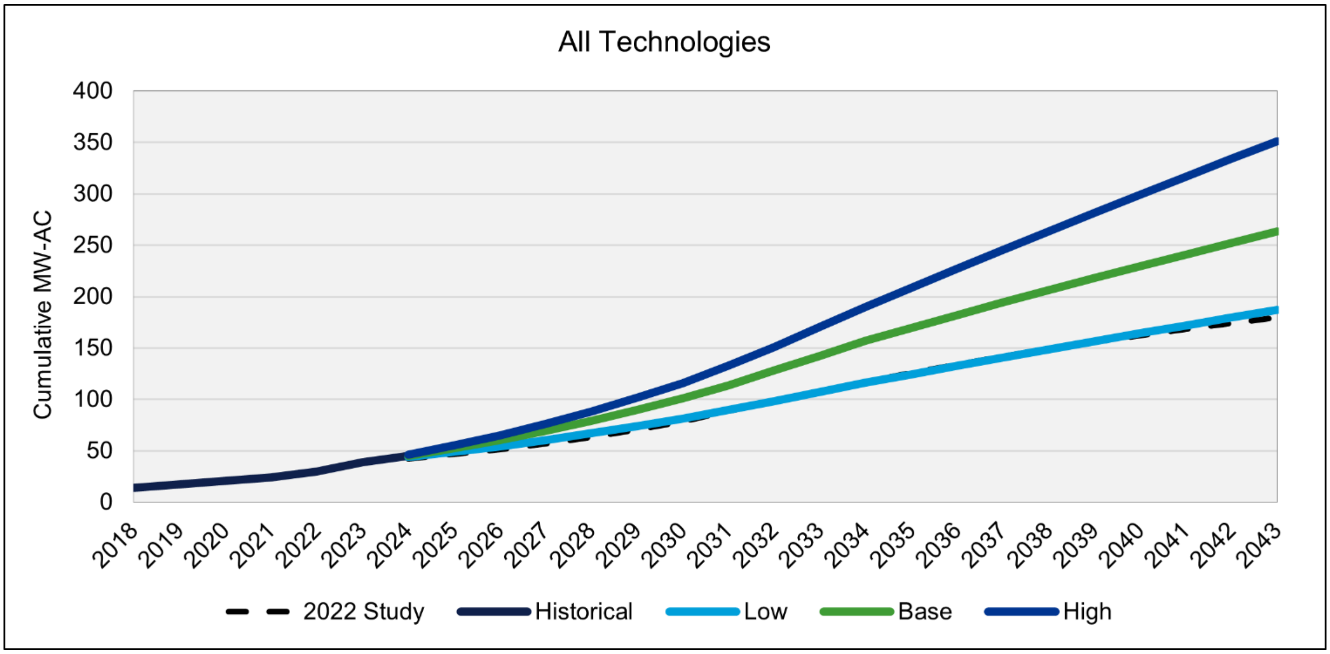


Figure 4-30. Cumulative new capacity installations by technology (MW-AC), Washington base case, 2024-2043

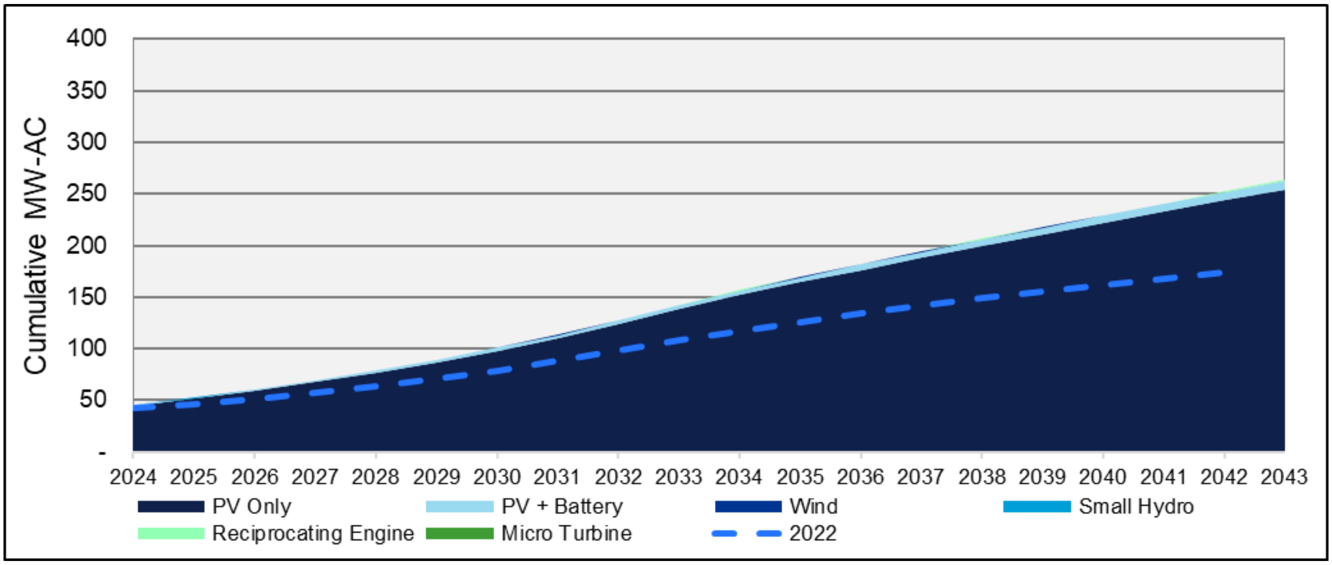


Figure 4-31. Cumulative new capacity installations by technology (MW-AC), Washington low case, 2024-2043

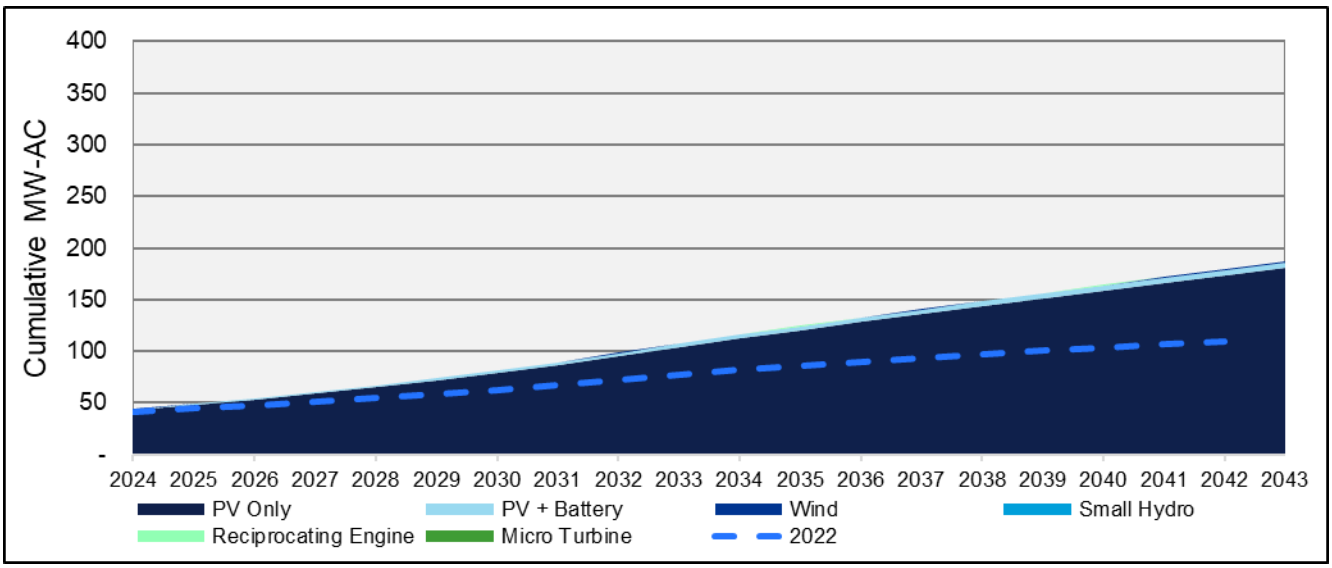
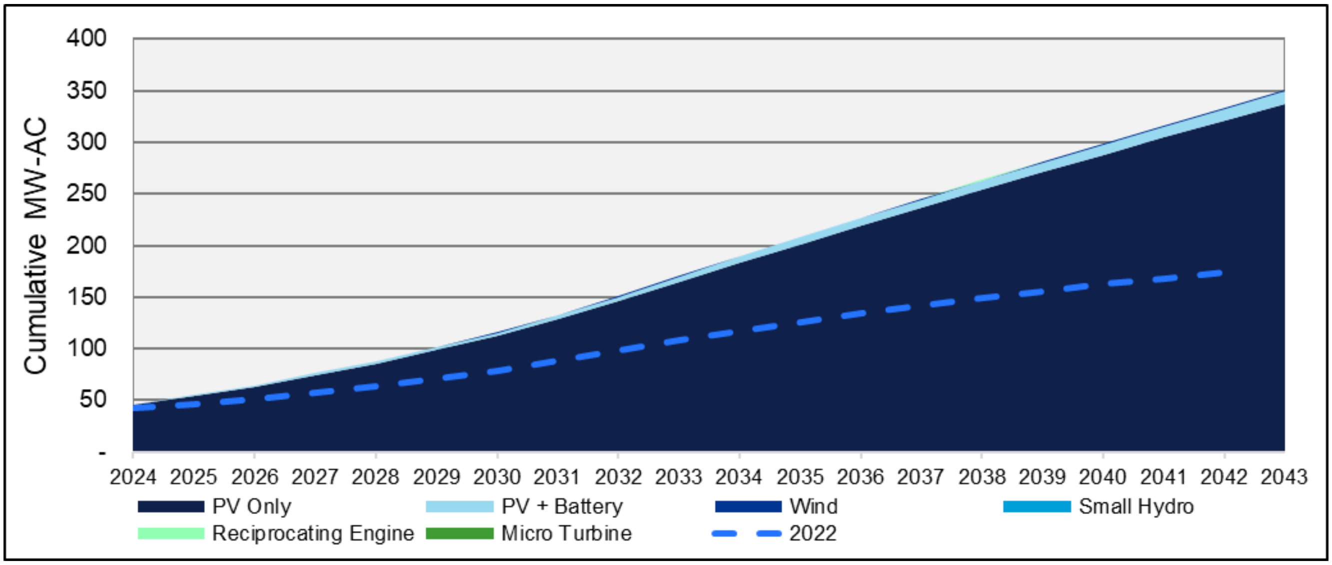


Figure 4-32. Cumulative new capacity installations by technology (MW-AC), Washington high case, 2024-2043

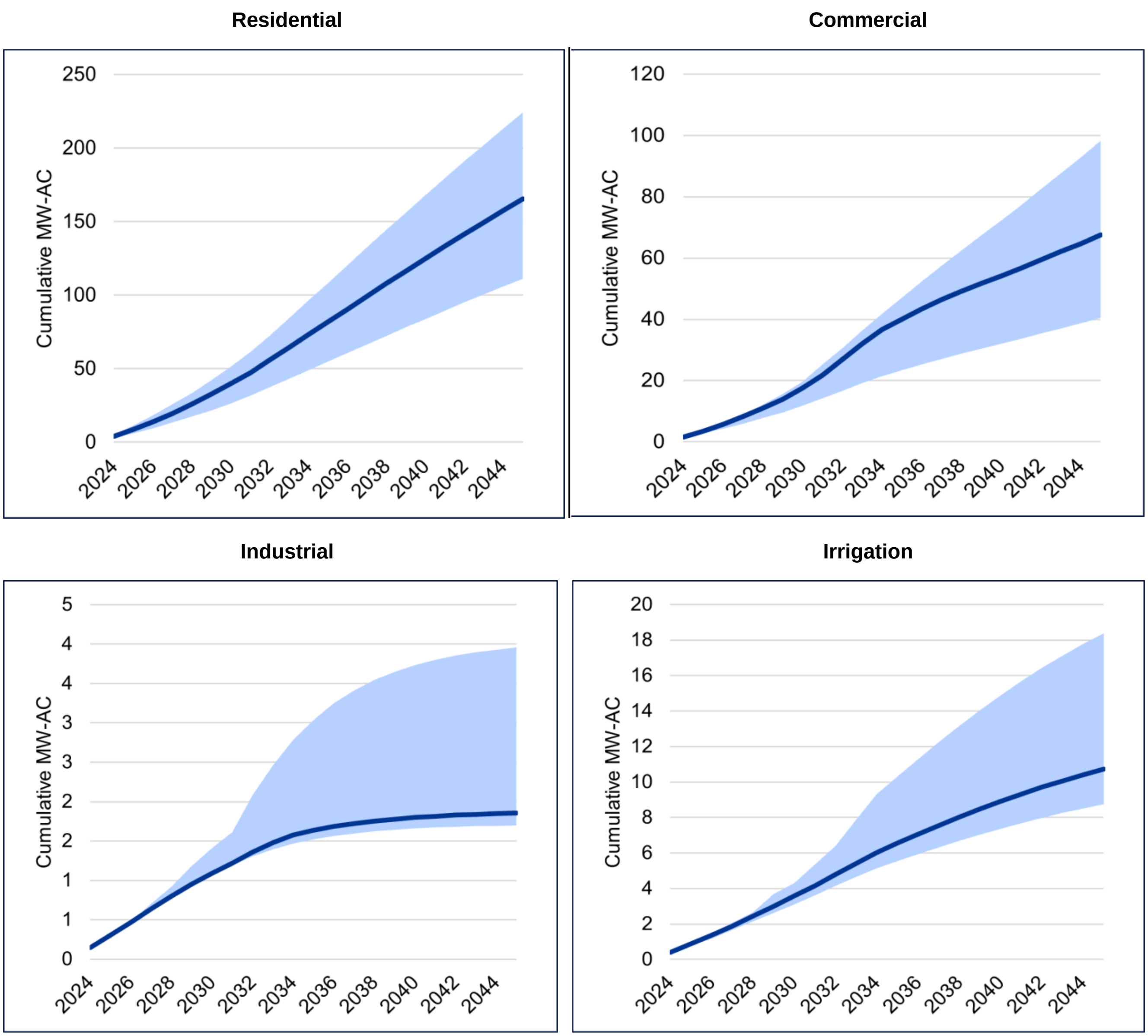


4.1.5.1 Washington PV adoption by sector

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

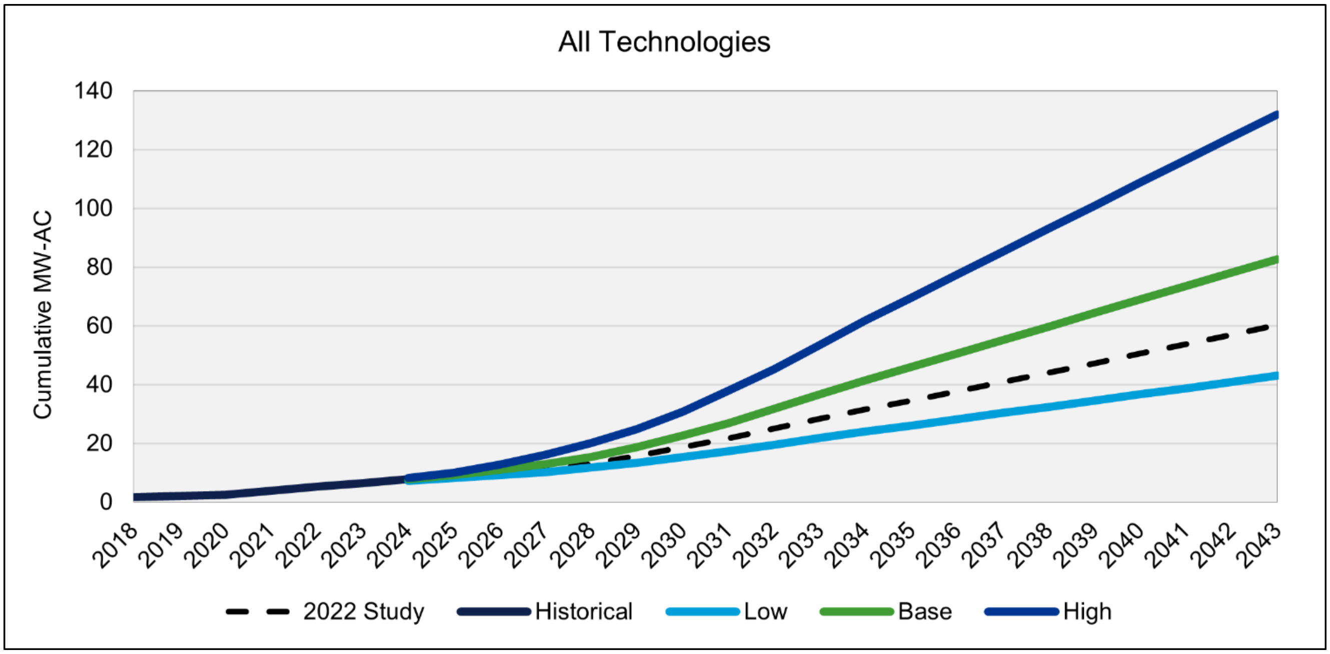


Figure 4-35. Cumulative new capacity installations by technology (MW-AC), Wyoming base case, 2024-2043

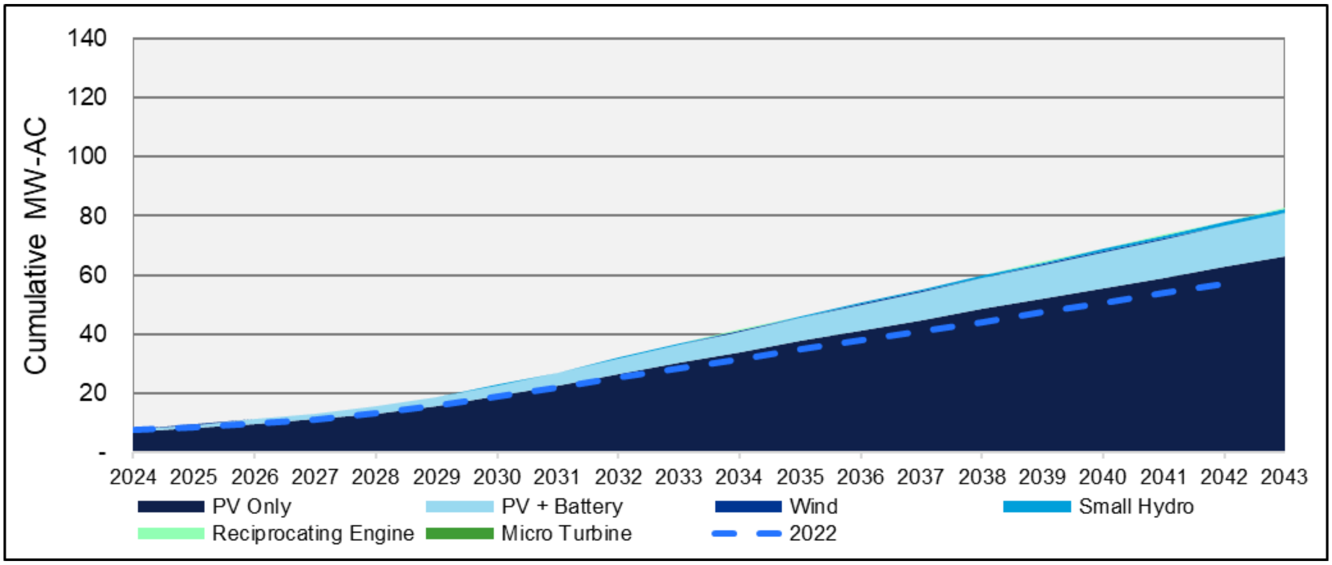


Figure 4-36. Cumulative new capacity installations by technology (MW-AC), Wyoming low case, 2024-2043

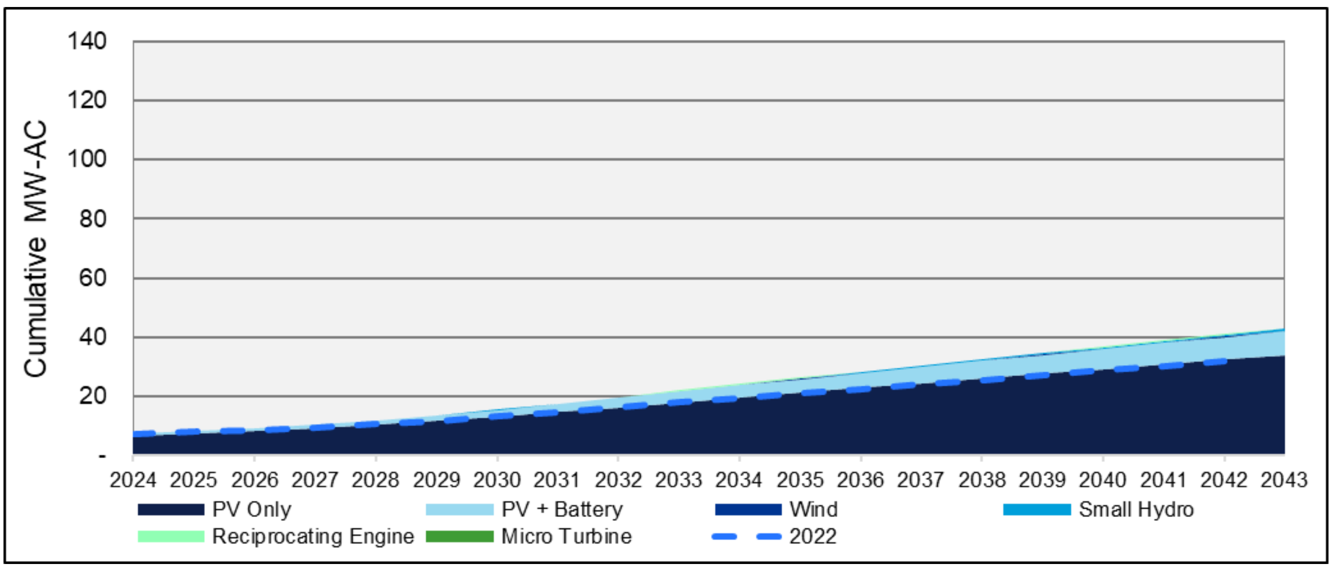
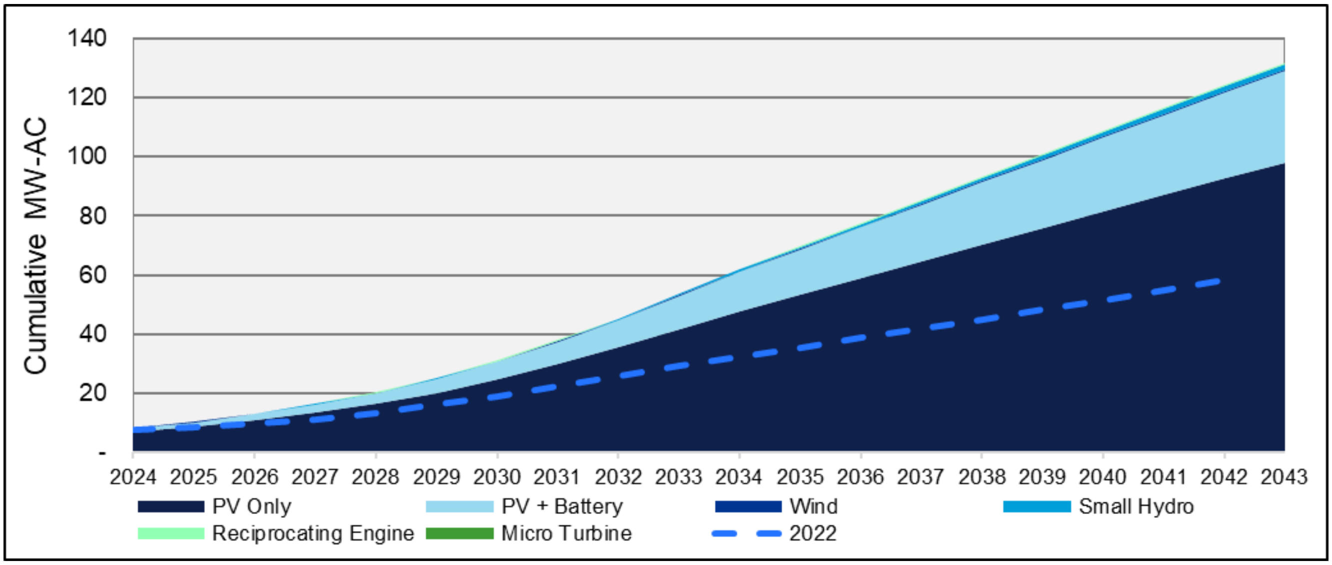


Figure 4-37. Cumulative new capacity installations by technology (MW-AC), Wyoming high case, 2024-2043

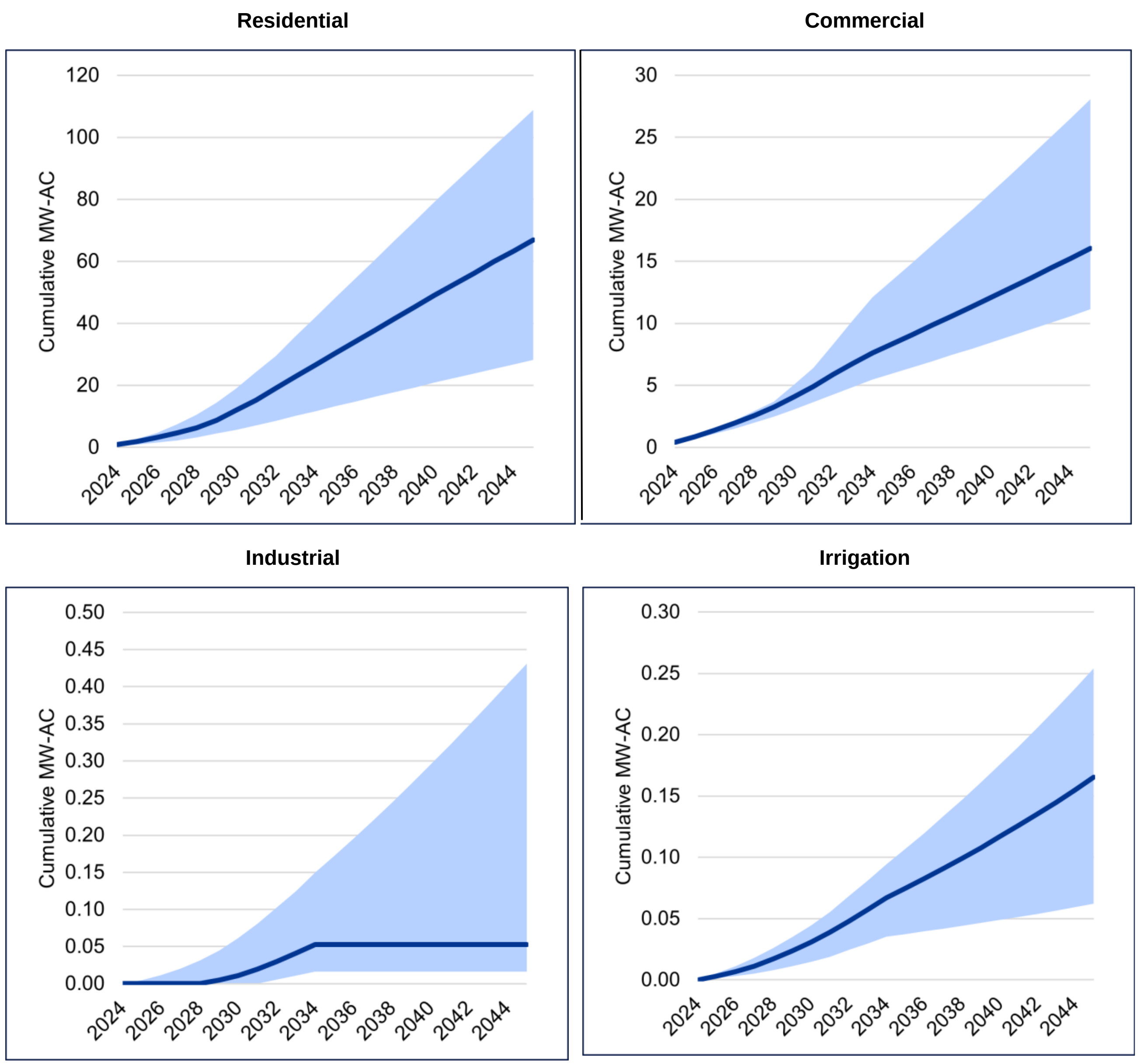


4.1.6.1 Wyoming PV adoption by sector

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

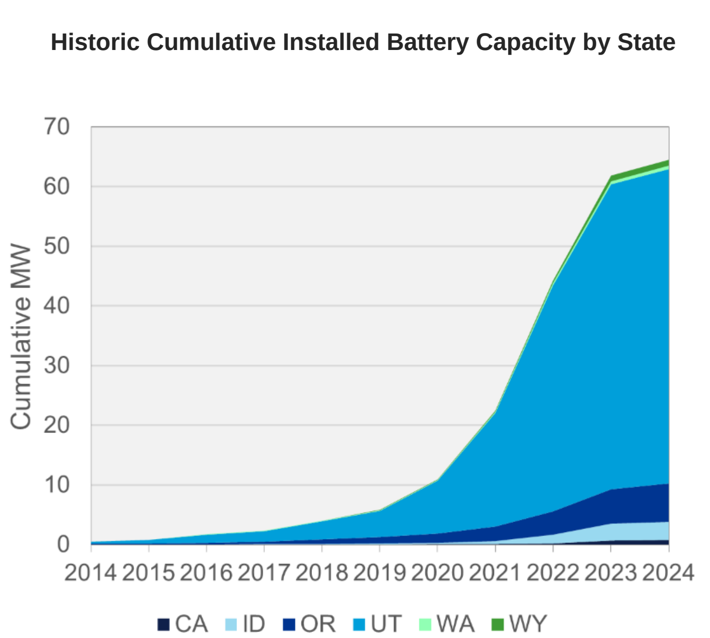
Appendix B.xlsx

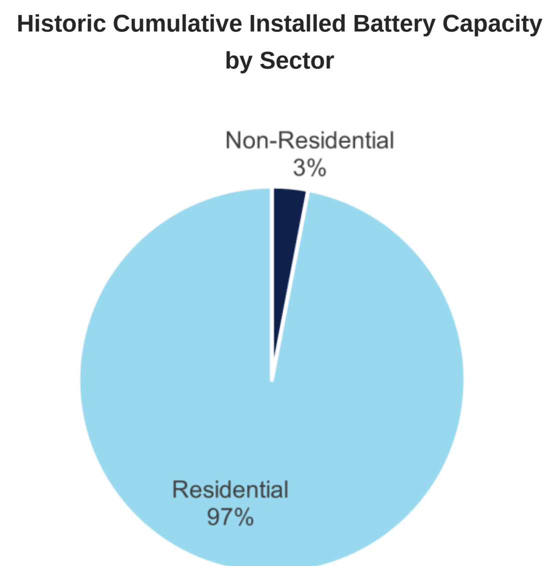
5.3 Behind-the-meter battery storage forecast

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.

[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

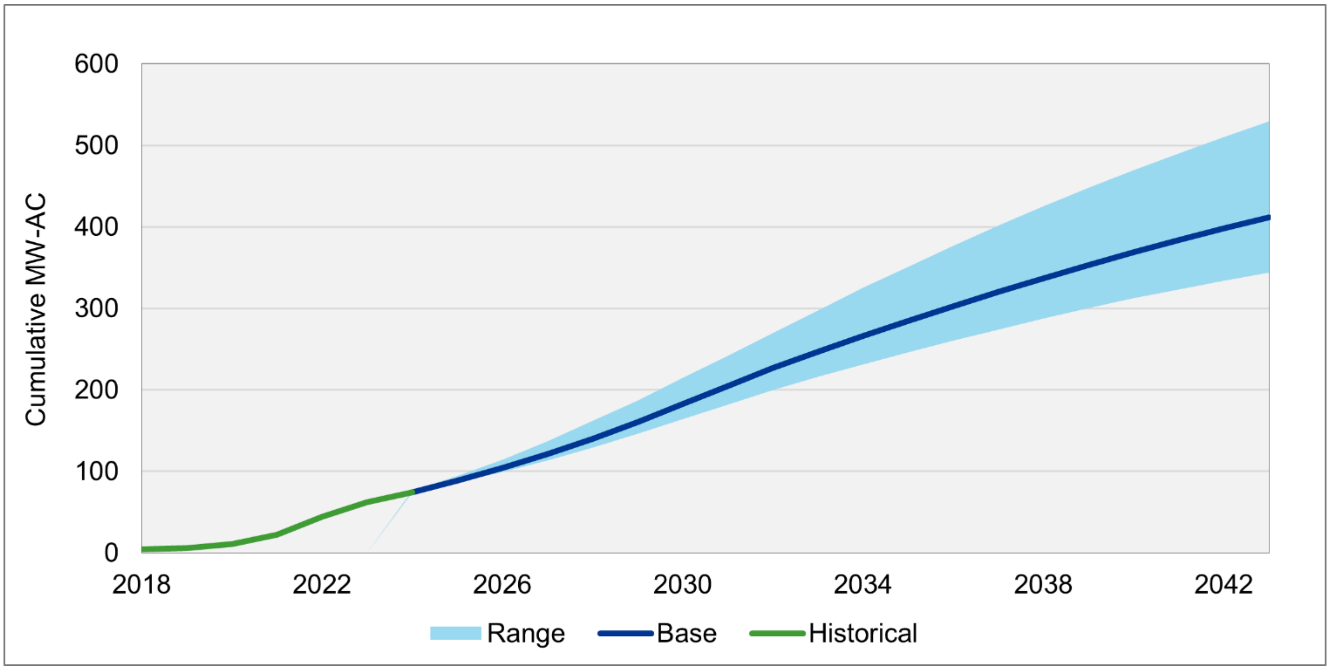


Figure 5-2 shows how the forecasts by customer sector and technology for each scenario. In all scenarios of the forecast, the residential sector represents about 90% of the new battery storage capacity forecasted to be installed over the next twenty years. The commercial, industrial, and irrigation sectors 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

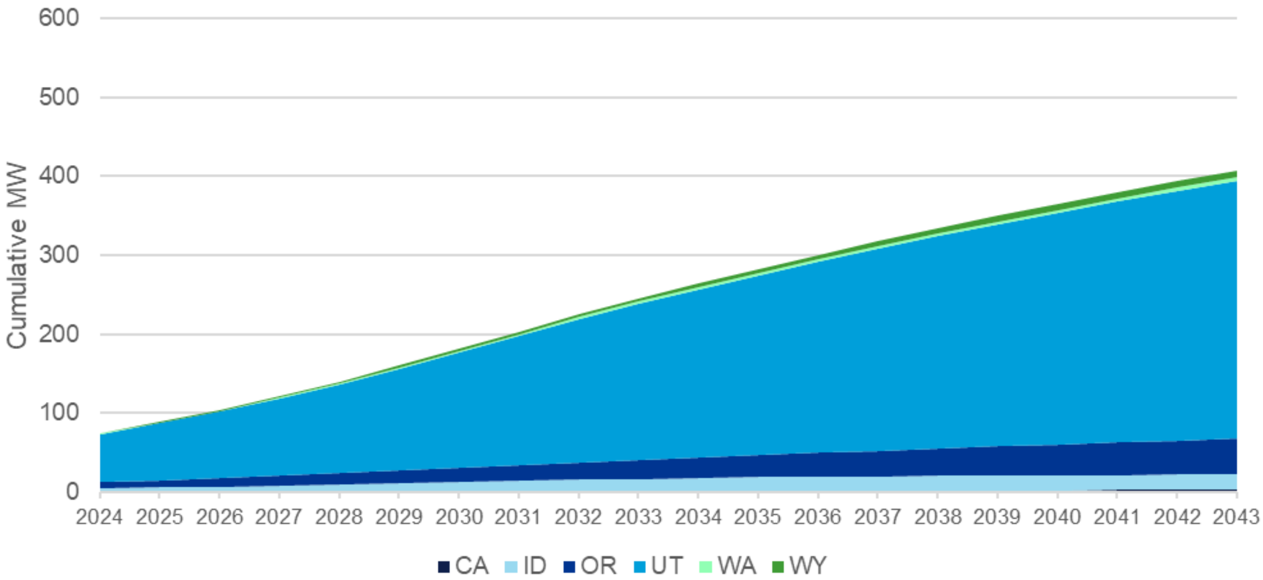


Figure 5-4. Cumulative new battery storage capacity installed by state (MW), 2024-2043, low case

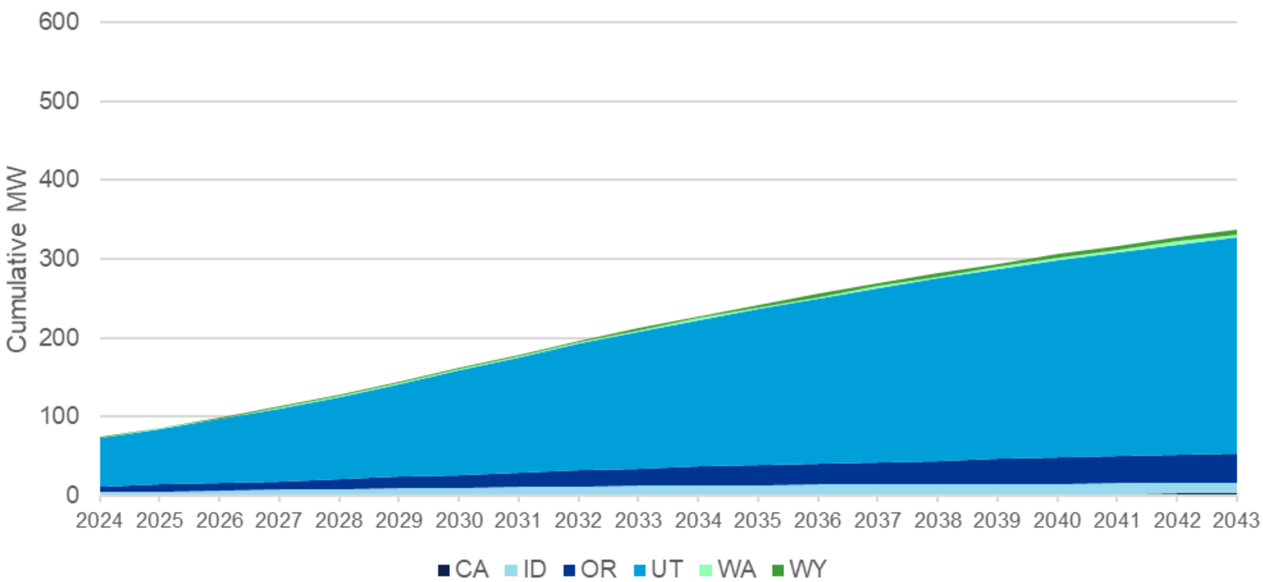
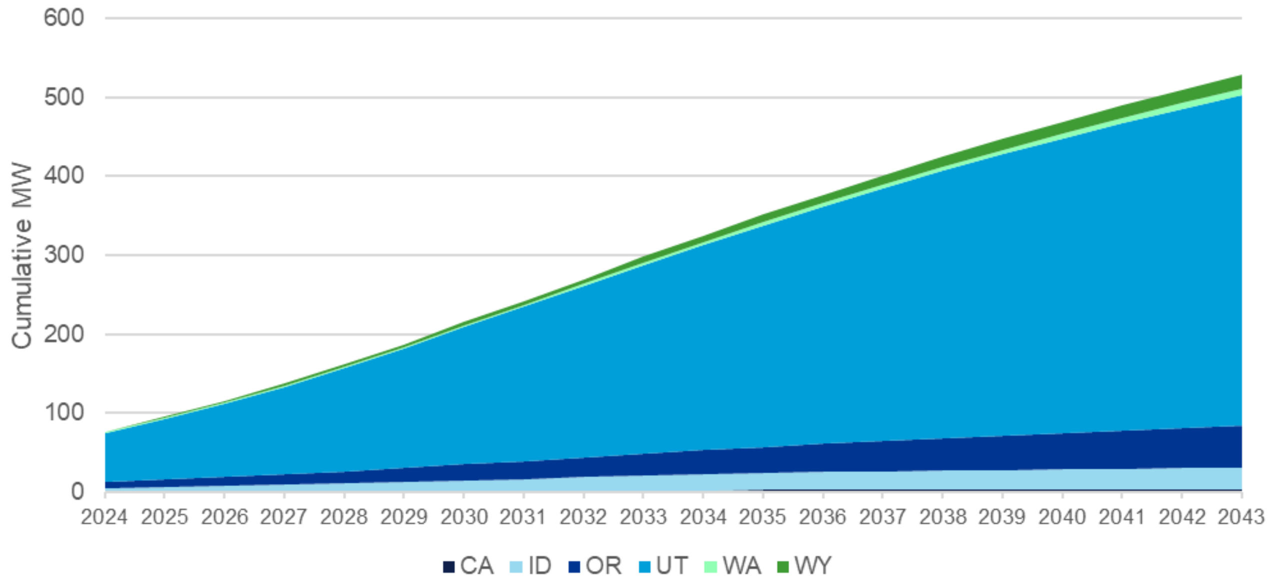


Figure 5-5. Cumulative new battery storage capacity installed by state (MW), 2024-2043, high case



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

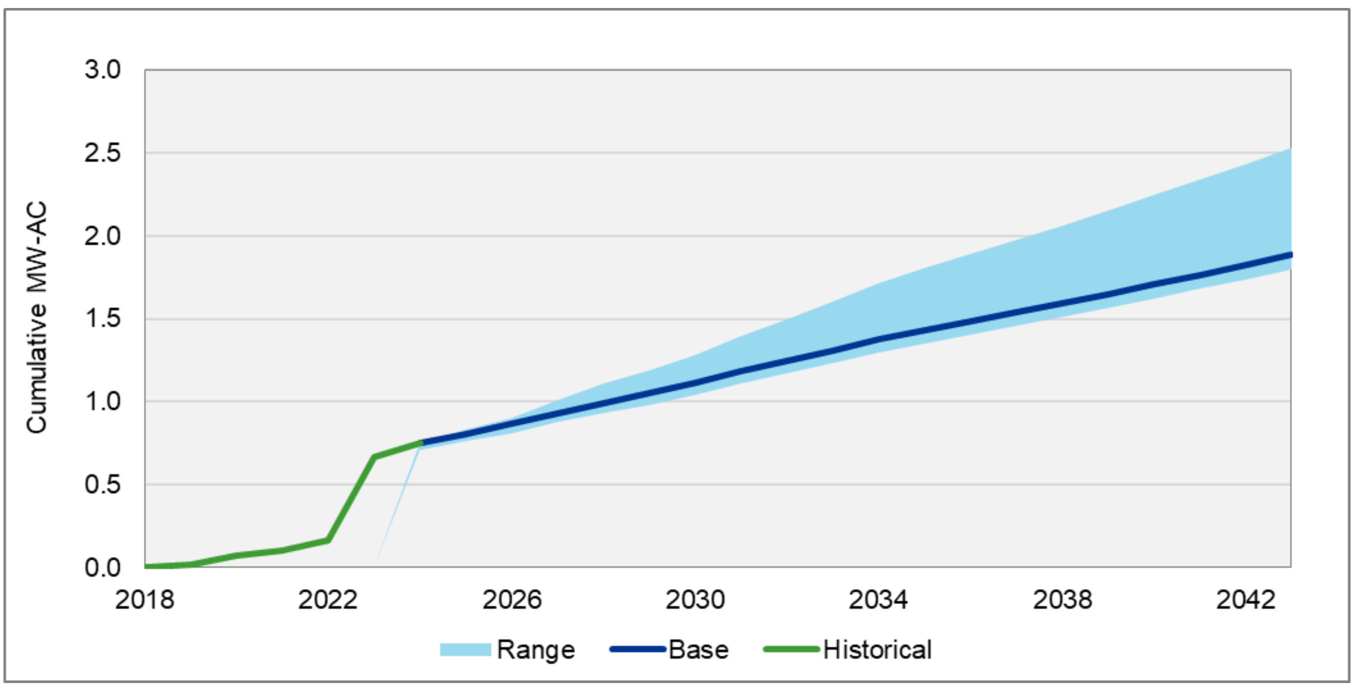
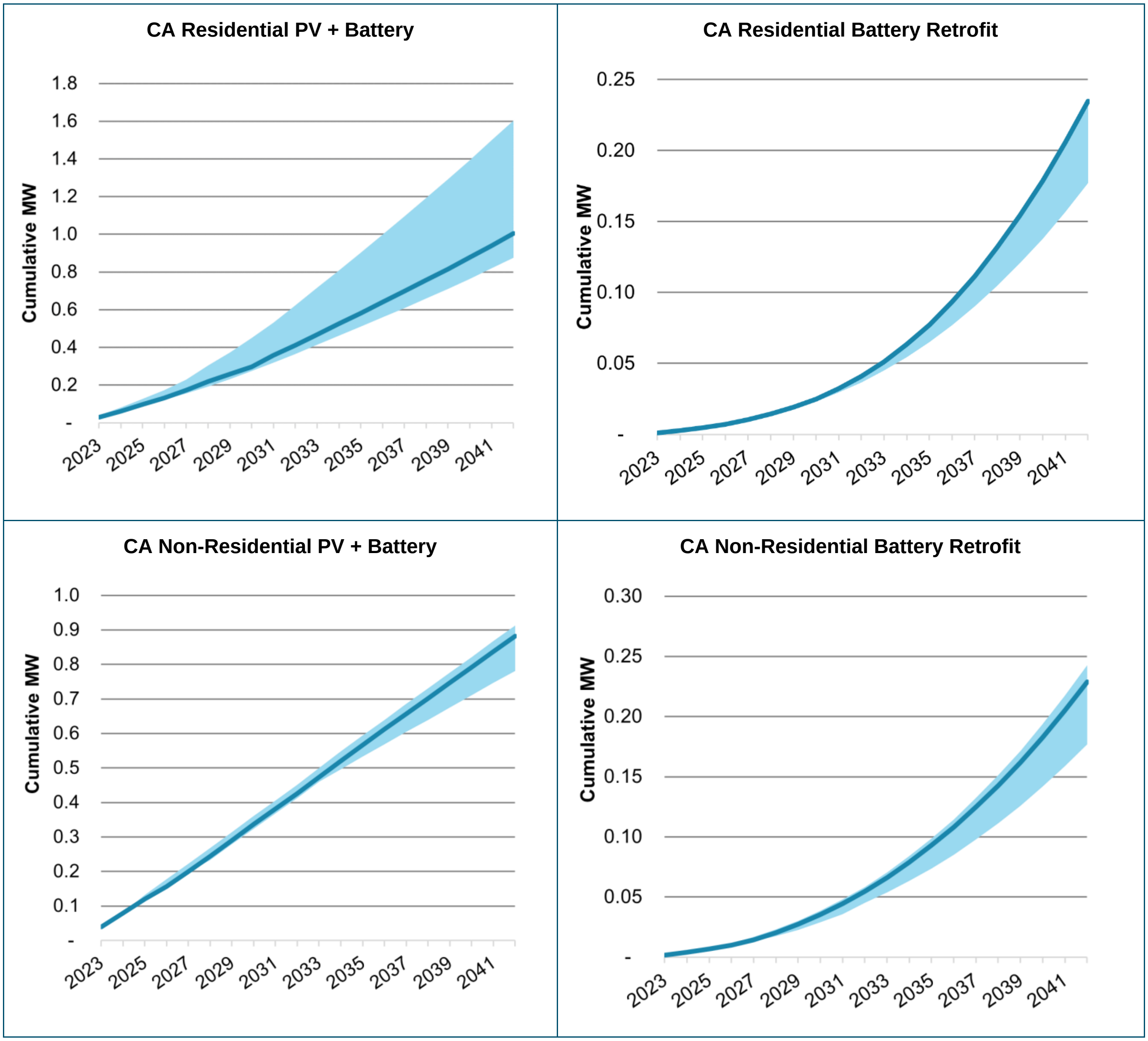


Figure 5-7. Cumulative new battery storage capacity installed by technology across all scenarios (MW), California, 2023-2042

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

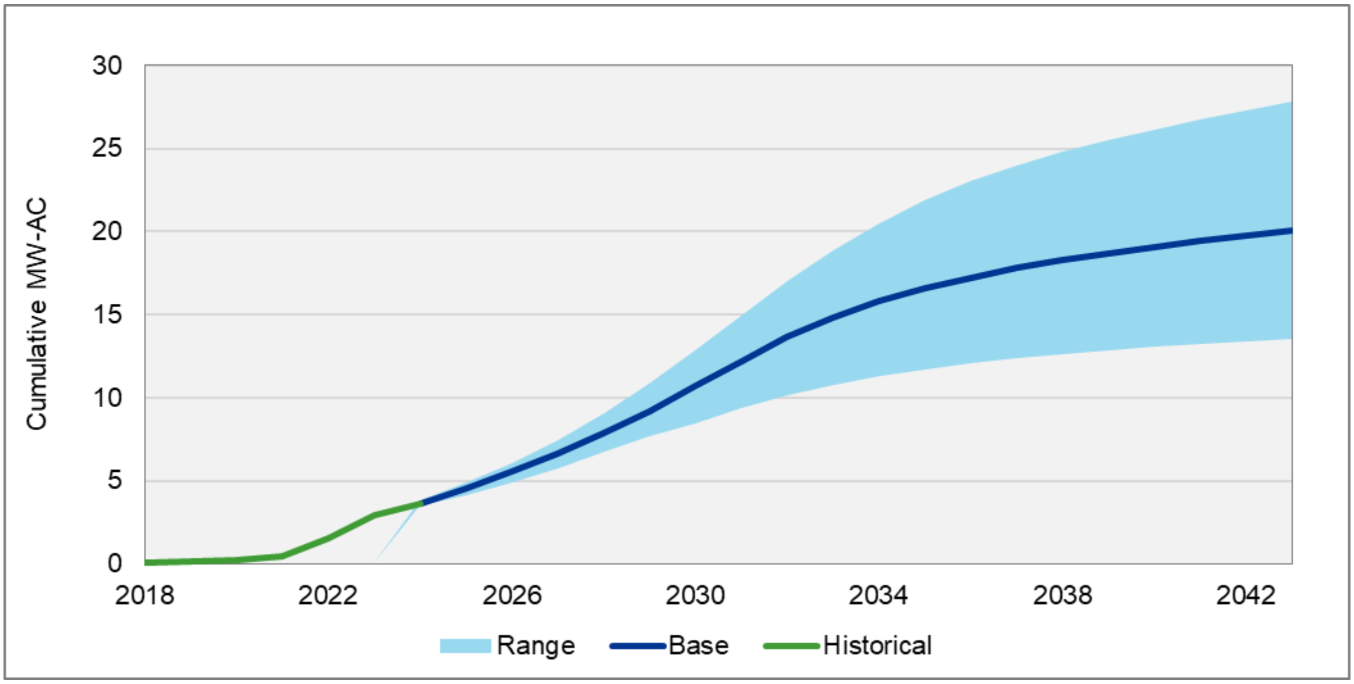
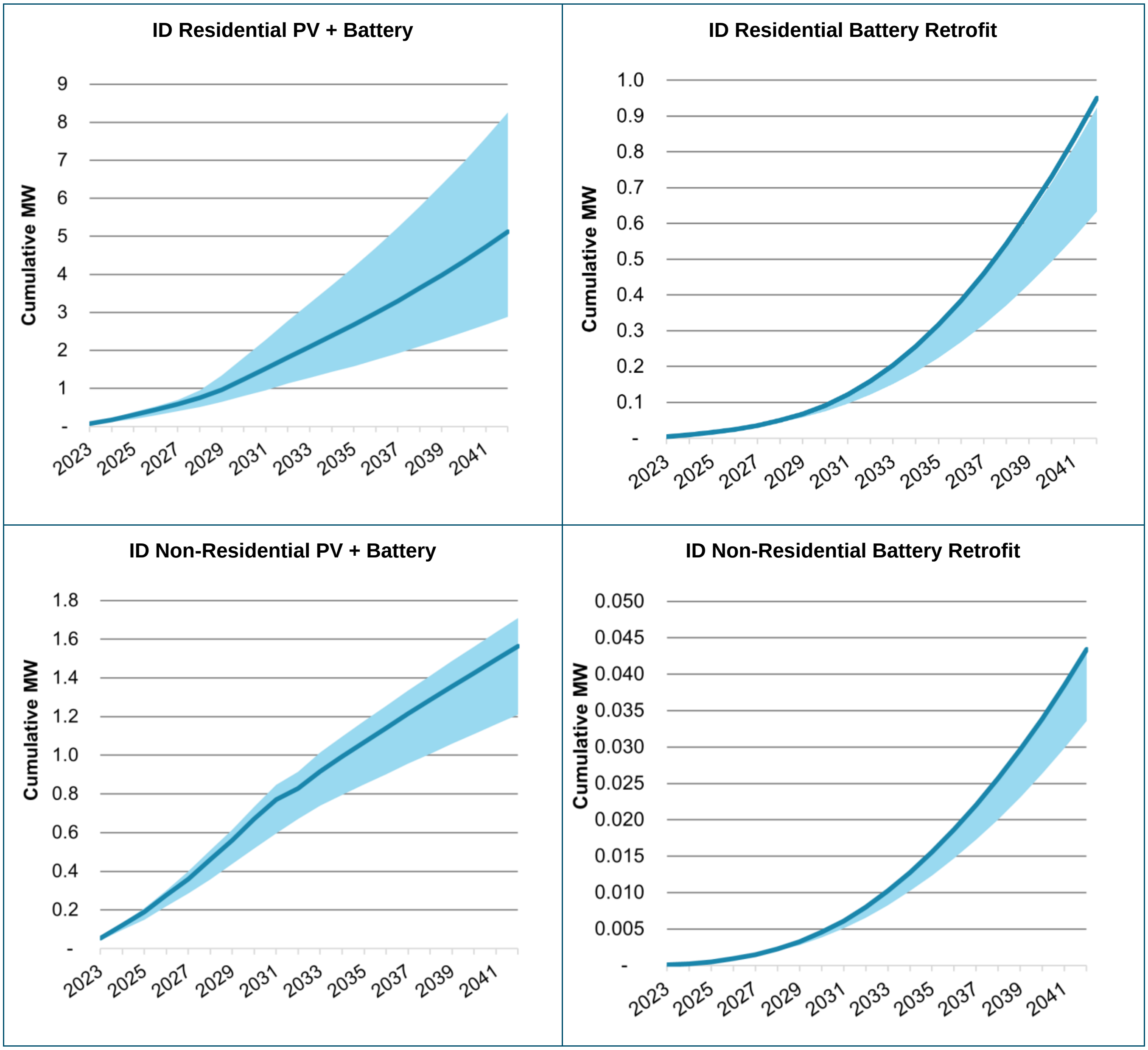


Figure 5-9. Cumulative new battery storage capacity installed by technology across all scenarios (MW), Idaho, 2023-2042

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

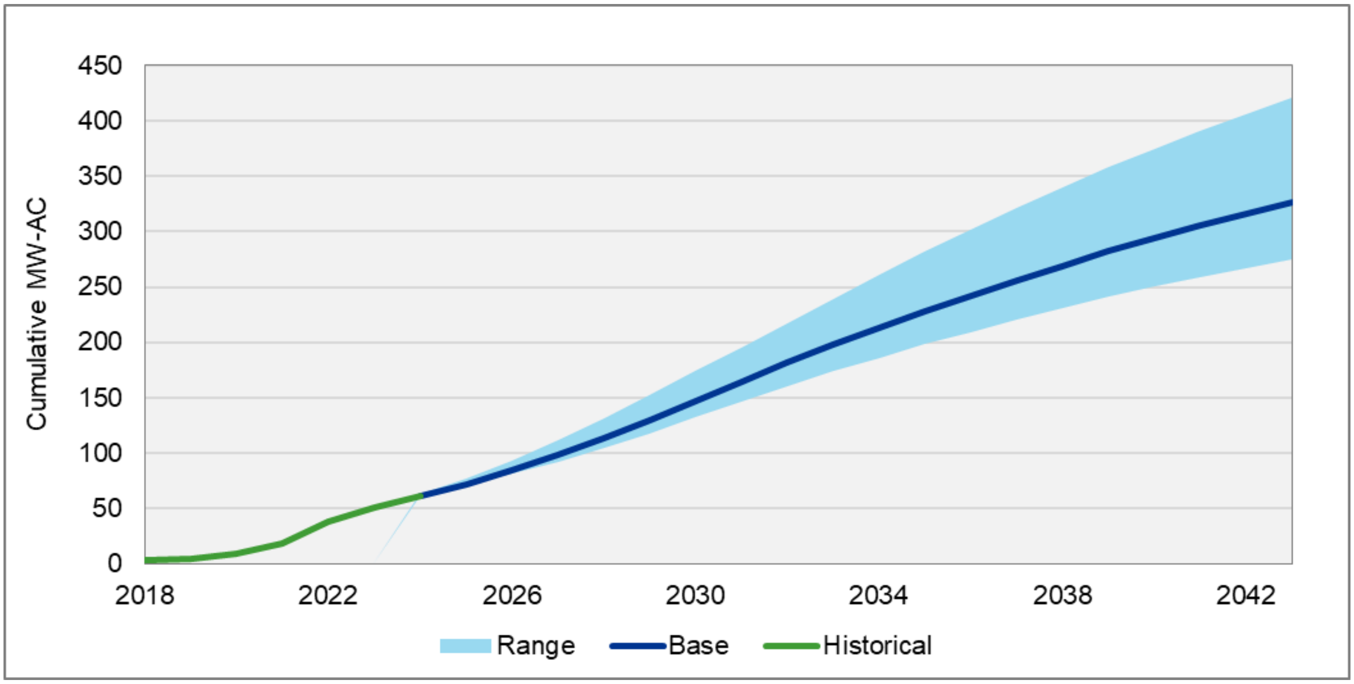
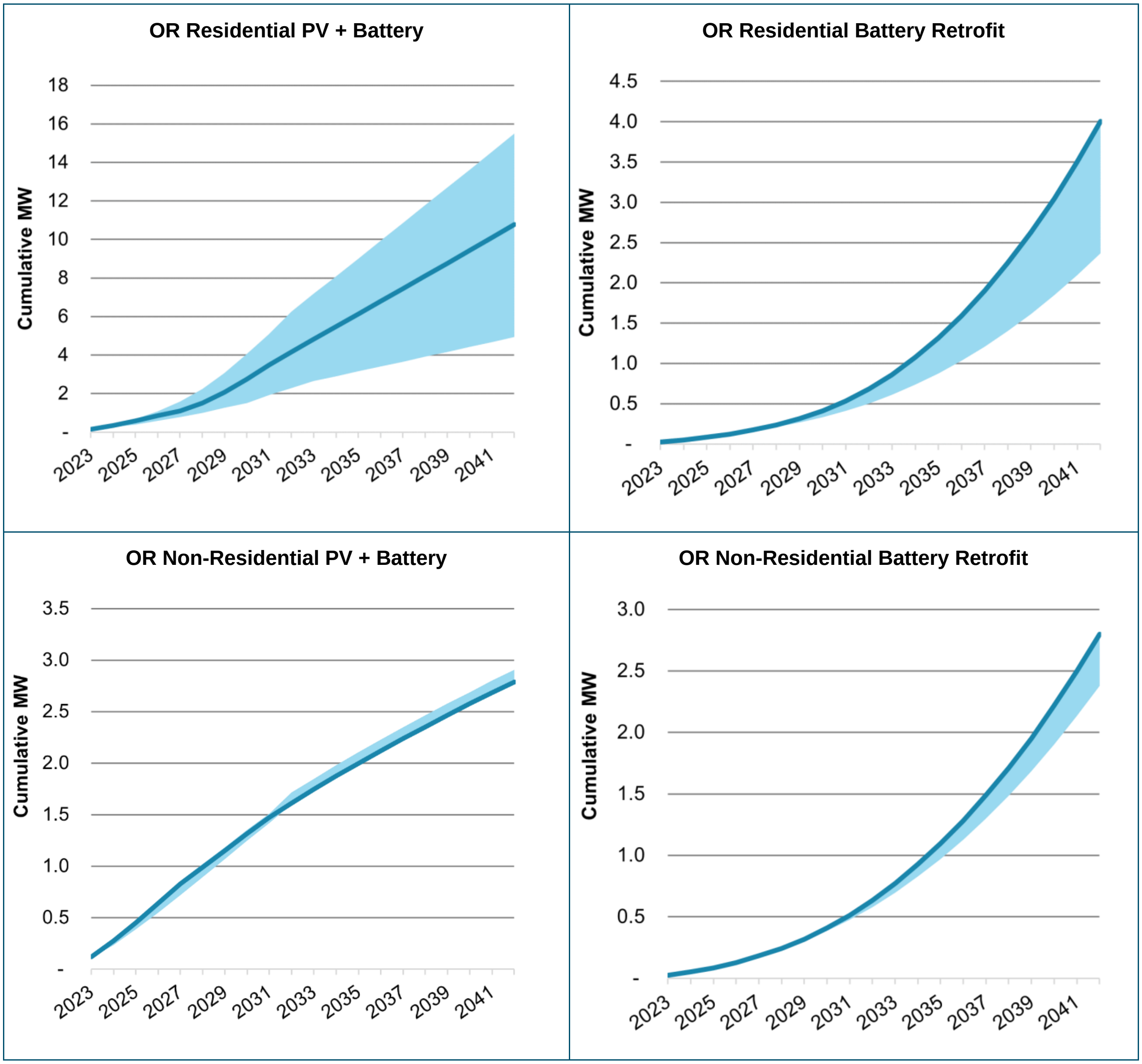


Figure 5-11. Cumulative new battery storage capacity installed by technology across all scenarios (MW), Oregon, 2023-2042

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

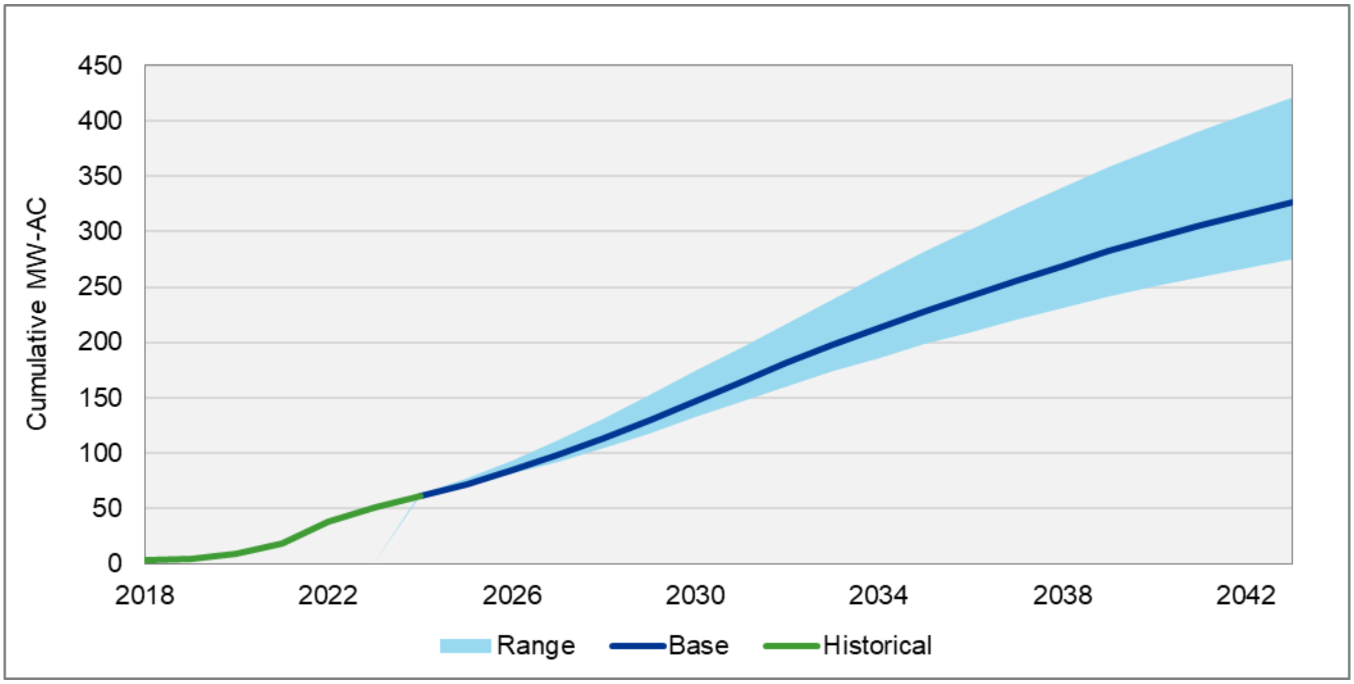
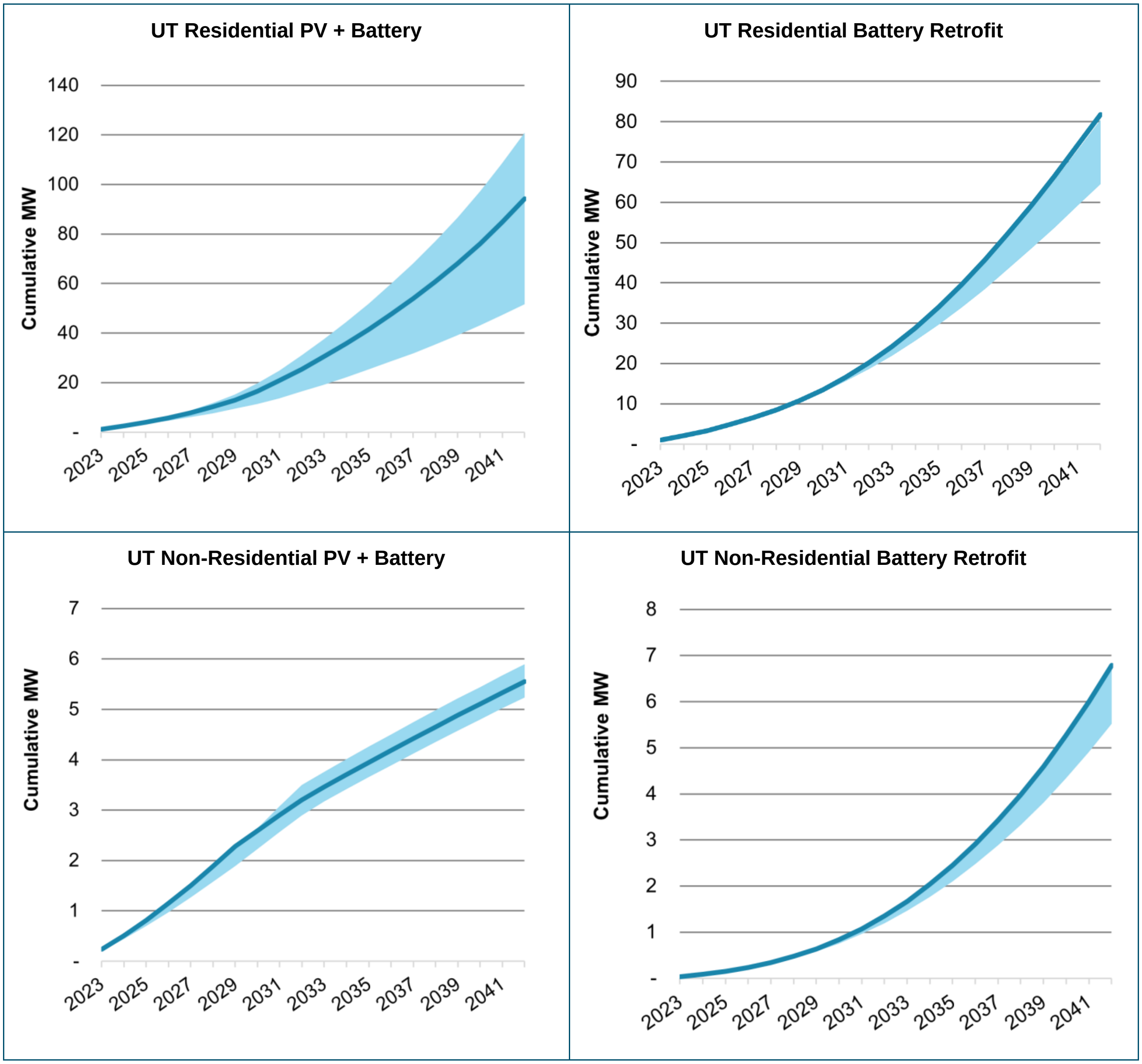


Figure 5-13. Cumulative new battery storage capacity installed by technology across all scenarios (MW), Utah, 2023-2042

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

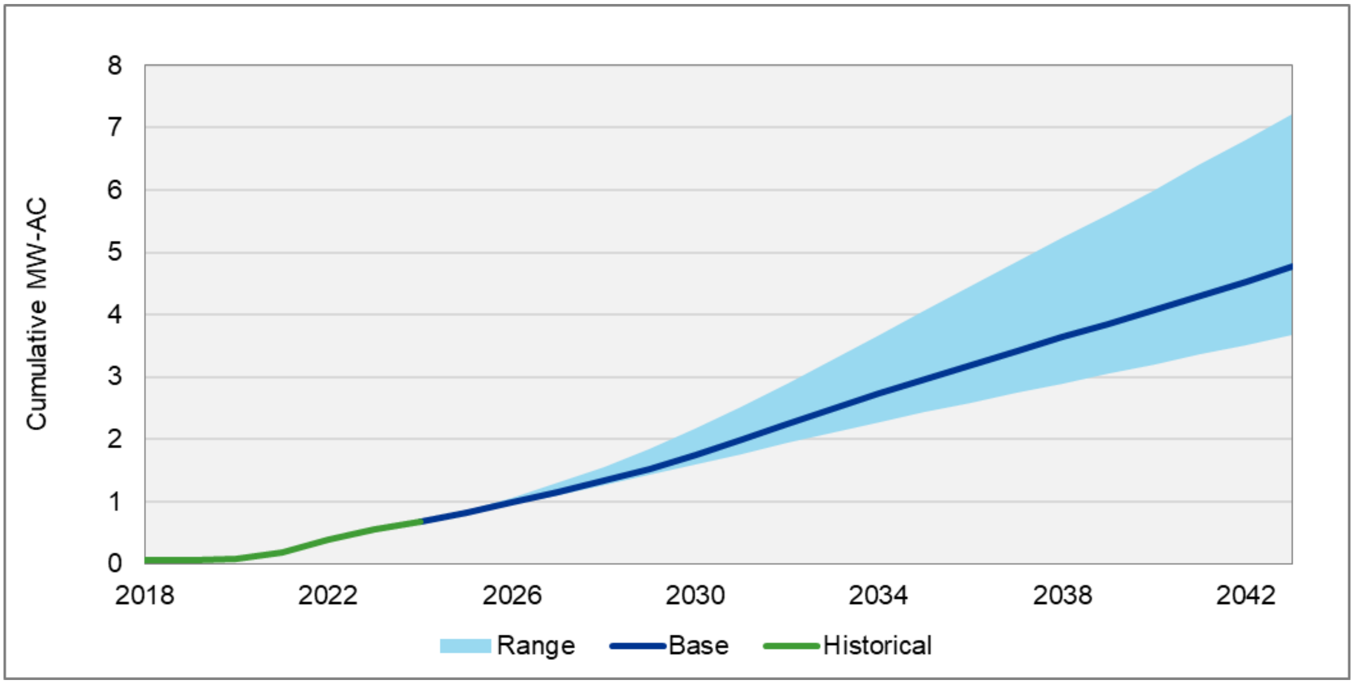
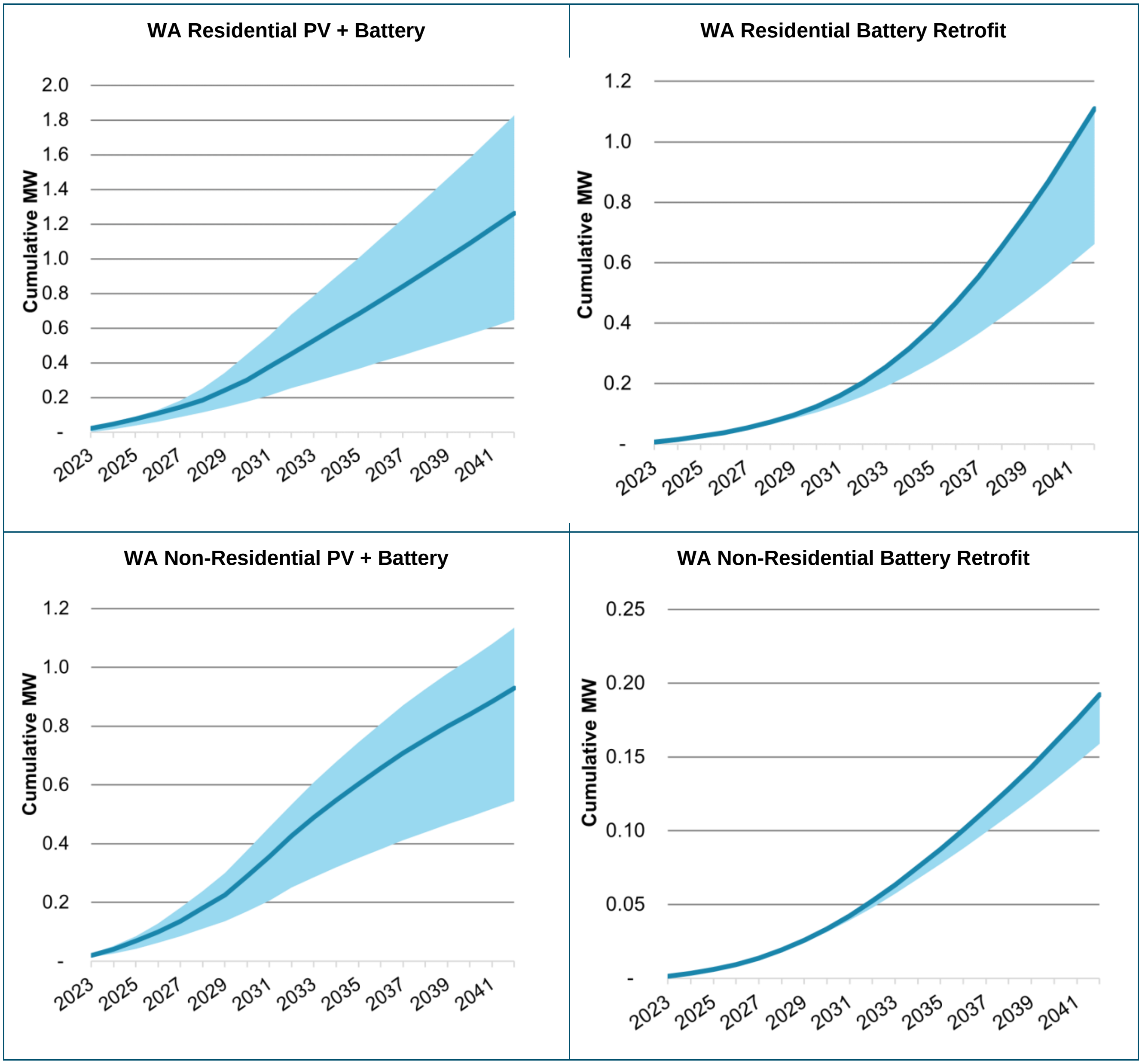


Figure 5-15. Cumulative new battery storage capacity installed by technology across all scenarios (MW), Washington, 2023-2042

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

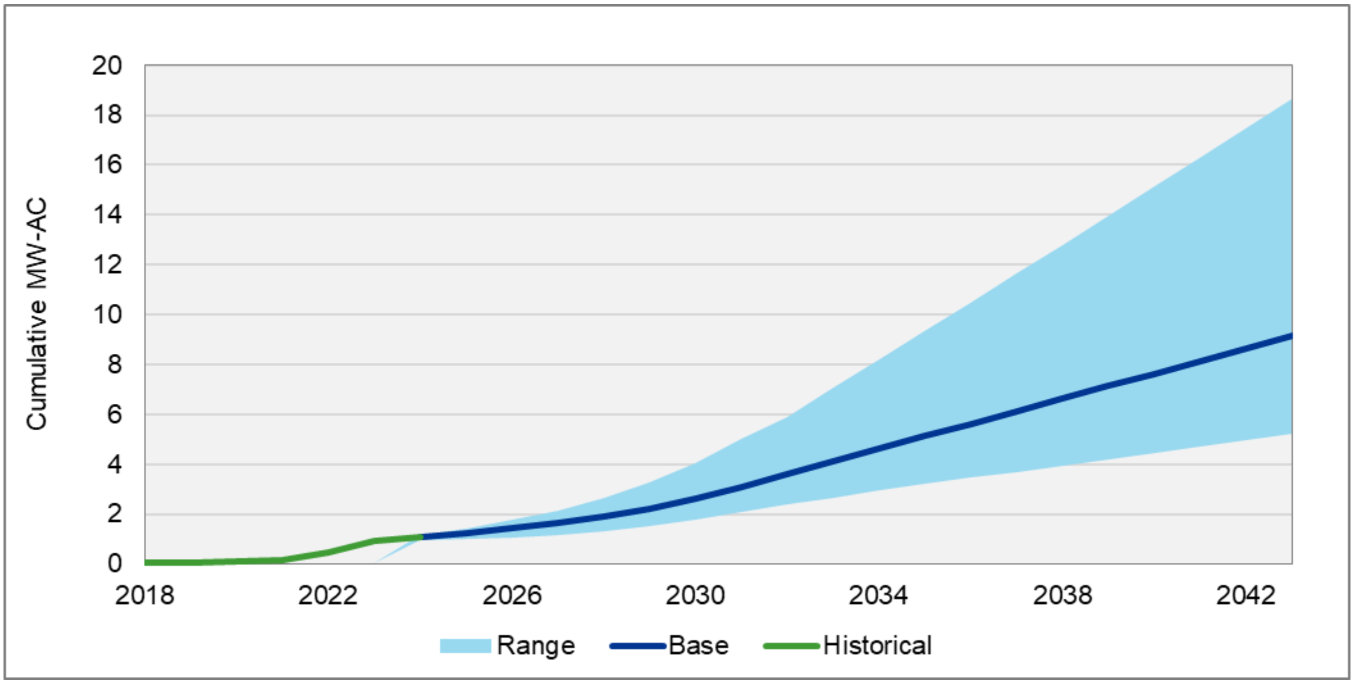
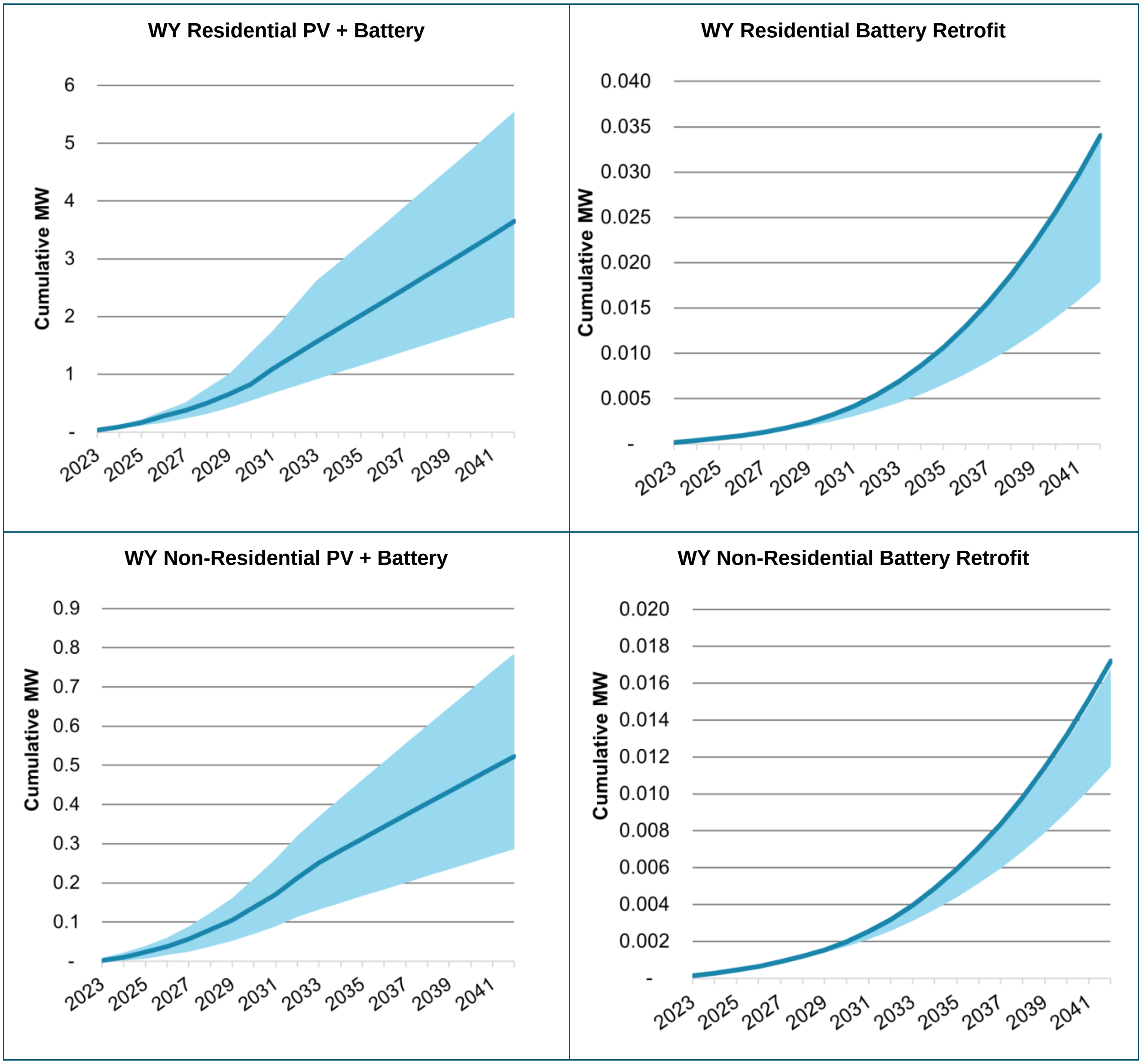


Figure 5-17. Cumulative new battery storage capacity installed by technology across all scenarios (MW), Wyoming, 2023-2042

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.

DNV

APPENDIX M – STAKEHOLDER FEEDBACK

Introduction

As of December 2024, stakeholder have submitted 46 stakeholder feedback forms, summarized below. PacifiCorp has responded to 40 of these submissions with public postings to the IRP website and six additional forms have been mailed. The stakeholder feedback forms have allowed the company to review and summarize issues by topic as well as identify specific recommendations that were provided. Information collected is 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 Draft 2025 IRP; refers to 2023 IRP and 2023 IRP Update

Requested Additional Studies

Stakeholder feedback forms provided approximately 45 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 seven request 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 seven 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 are 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 will be addressed by the study limiting access to all markets. Note also that in the 2025 IRP it is assumed that there is no market availability during peak hours.

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 will be addressed by the study limiting access to all markets.

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

* Required fields

https://en.wikipedia.org/wiki/Flamanville_Nuclear_Power_Plant#Unit_3
https://en.wikipedia.org/wiki/Olkiluoto_Nuclear_Power_Plant#Unit_3

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.

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.

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

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:

***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.
```

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.

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.

* Required fields

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?

* 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.

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.

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

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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

* Required fields

quantitative information that justifies the increased renewable resource cost estimates.
4. How does PacifiCorp plan to forecast renewable resource costs 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.

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.

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

* Required fields

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.

* Required fields

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):

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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.

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

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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).

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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.

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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.

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PacifiCorp - Stakeholder Feedback Form (014)

2023 Integrated Resource Plan

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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:

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.
2023 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 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.

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 resume the 2022 all source RFP that was proposed in 2021.

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)

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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.

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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

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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.

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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.

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Thank you for participating.

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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?

- **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?
   - **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.
      - 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.
      - 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.
      - 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.
      - 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.
   - **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?
   - **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?
   - **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.

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

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.

* Required fields

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

* Required fields

appeal the CCA. Chehalis provides capacity to the system and demonstrated cost-effectiveness in the 2023 IRP.

Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com

Thank you for participating.

* Required fields

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:**

* Required fields

- 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
- 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?
- 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.
- 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.
- 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.

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

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

* Required fields

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.
```

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

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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

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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?

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.

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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?

* Required fields

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.

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PacifiCorp - Stakeholder Feedback Form (026)
Integrated Resource Plan

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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

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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.

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

Recommendations: Provide any additional recommendations if not included above - specificity is greatly appreciated.

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?

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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

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PacifiCorp - Stakeholder Feedback Form (027)
Integrated Resource Plan

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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.

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

Thank you for participating.

* Required fields

PacifiCorp - Stakeholder Feedback Form (028)
Integrated Resource Plan

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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.

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

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.

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
Title:

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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.

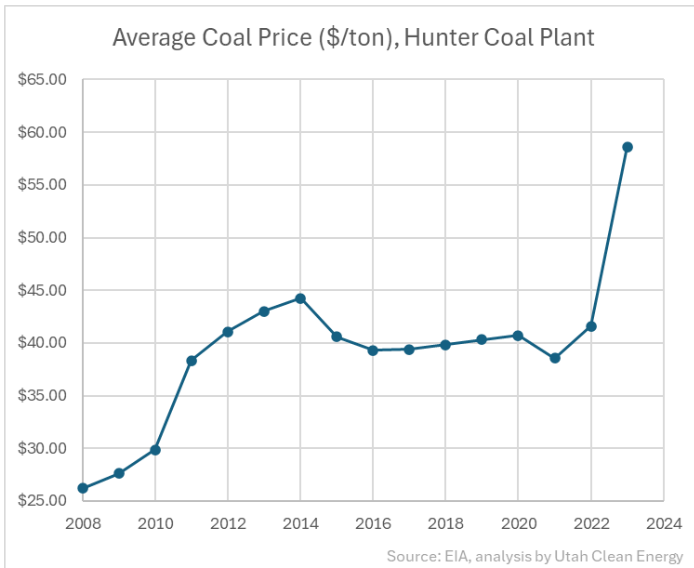
[3] See https://pscdocs.utah.gov/electric/24docs/2403504/334494RdctdDirTstmnyRamonJMitchellRMP6-28-2024.pdf.

* Required fields

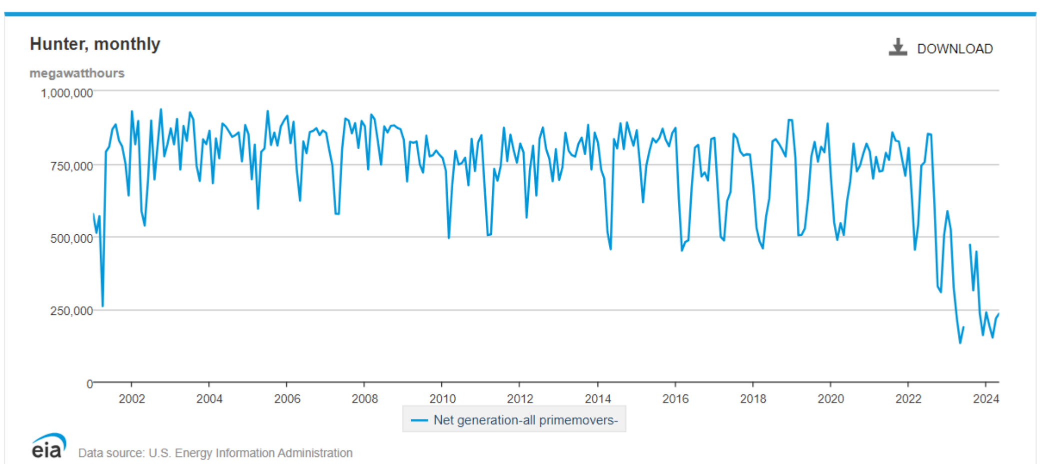
closure of Lila Canyon created a significant coal production shortfall in Utah in 2023 and will continue to have negative impacts to all large consumers, including the Company, in 2024 and potentially 2025.

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]

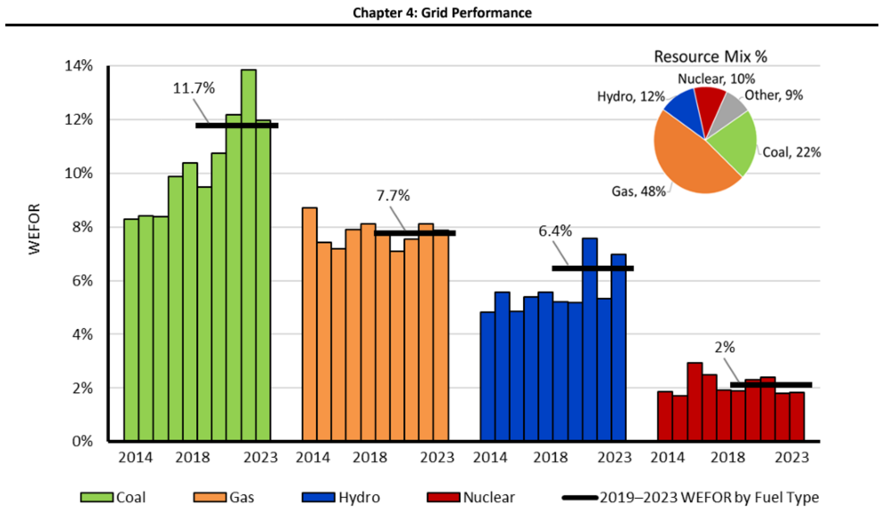


Figure 4.5: 10-Year Annual WEFOR by Fuel Type and 2023 Resource Mix by Net Maximum Capacity

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

- 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.

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.

Recommendations: Provide any additional recommendations if not included above - specificity is greatly appreciated.

- See above

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.

* Required fields

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.

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 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.

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

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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.

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 (035)

Integrated Resource Plan

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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

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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:

* Required fields

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.

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

Recommendations: Provide any additional recommendations if not included above - specificity is greatly appreciated.

Please see above

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

[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

[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.

<u>Granularity Adjustments</u>

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.

<u>Reliability Adjustments</u>

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 1^{st}, 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.

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%.

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.

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.

Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com

Thank you for participating.

PacifiCorp - Stakeholder Feedback Form (040)
Integrated Resource Plan

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Date of Submittal 2024-09-12

*Name: Jim Himelic Title:
*E-mail: jhimelic@firstprinciples.run Phone:
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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.

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 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

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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?
  - o 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?
  - o 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?
  - o 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?
  - o Are any of these costs—triggered by cluster studies from previous years—assigned to the projects listed in Table 4?
  - o 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?
  - o 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

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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.

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 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.

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 (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

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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.

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PacifiCorp - Stakeholder Feedback Form (042)

Integrated Resource Plan

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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.

***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.

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

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.

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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:

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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

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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.

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. 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.

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.

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PacifiCorp - Stakeholder Feedback Form (045)

Integrated Resource Plan

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Date of Submittal: 2024-11-18

*Name: Kevin Emerson
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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

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realistic level of energy saving potential associated with utility-sponsored new homes rebate programs.

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
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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.

APPENDIX O – WASHINGTON CLEAN ENERGY ACTION PLAN

Introduction

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 new 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 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;

[1] 2019 WA Laws Ch. 288.
[2] WAC 480-100-620.
[3] WAC 480-100-640.

(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).

The following sections describe how a long-run portfolio is optimized to meet CETA's clean energy standards at least-cost, least-risk, in accordance with the requirements defined above.

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.

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.

The company's long-term load forecasts (both energy and coincident peak load) for the system are summarized in Volume I, Chapter 6 (Load and Resource Balance) as well as for each state in Appendix A (Load Forecast Details). The summary-level system coincident peak is presented first, followed by a profile of PacifiCorp's existing resources. Finally, load and resource balances for capacity and energy are presented. These balances are composed of a year-by-year comparison of projected loads against the existing resource base, with assumed incremental new energy efficiency savings from the preferred portfolio, before adding new generating resources.

Resource Portfolio Development

As discussed in Volume I, Chapter 8, PacifiCorp uses the Plexos 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. The portfolio modeling and selection process leads to an optimized, lowest reasonable cost six-state integrated portfolio to serve PacifiCorp's customers.

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.

Resource Adequacy

As described in Volume I, 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 planning requirements within the LT model to account for shortfalls identified within the more granular ST model.

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 social cost of greenhouse (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 final draft preferred portfolio, integrates all system and state-specific resources into one final 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 clean energy targets.

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 Washington Inter-Jurisdictional Allocation Methodology (WIJAM) for existing resources and generally assumed that these assumptions hold into the future, in the absence of an agreed upon future allocation methodology.[4] All new proxy resources (renewable or non-emitting resources, only) are assumed to be either acquired for, and therefore allocated to, the system or are an incremental requirement to satisfy state-specific compliance and are therefore situs allocated to the state of origin. 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 and nuclear.[5] In summary, the resource allocation assumptions are:

1. Allocation of energy for all renewable resources (non-QFs), existing and proxy, 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 and benefits from Jim Bridger Units 1-2 after they convert to run on natural gas start 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.

[4] 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.

[5] 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".

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.
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, hydro, 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 generation (coal or gas-fueled resources) 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 Utilities Regulatory Policies Act of 1978 (PURPA).[6] 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 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.

Interim Targets

RCW 19.405.040 and 19.405.050 set the 2025, 2030, and 2045 goals for electric utilities in Washington to meet. Specifically, utilities must show that by December 31, 2025, all coal-fired generation has 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.

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

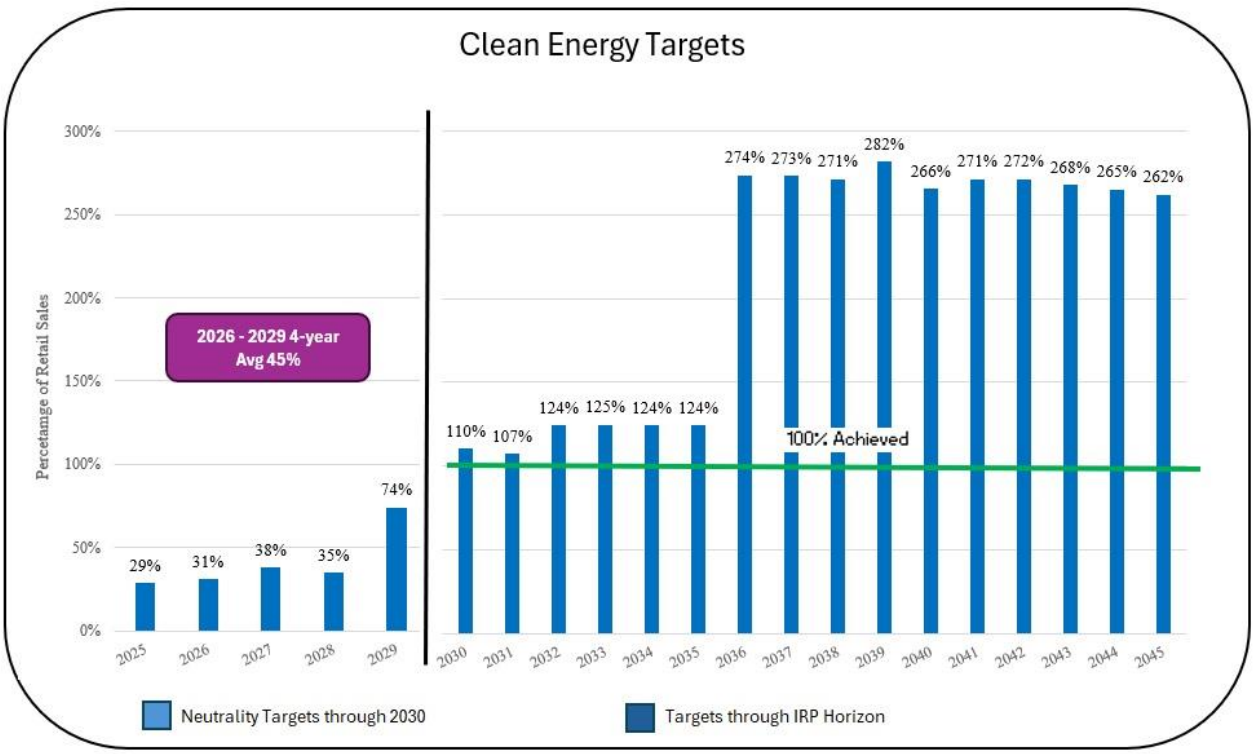
[6] RCW 19.405.020(36)(a)

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.

The Draft 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.1.

Figure O.1 -- Clean energy interim targets for Washington customers from 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. PacifiCorp is conducting stochastic analysis for inclusion in the final IRP filing that includes annual variation in hydro, wind, and solar generation based on historical weather conditions. 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.1 below reports updated interim targets for the Company's second CEIP planning period for years 2026-2029, reported as annual megawatt hours of energy rather than as percentages.

Table O.1 – Clean energy interim targets for Washington customers 2026-2029

	2026	2027	2028	2029	Total
Retail Electric Sales	4,081,072	4,250,939	4,428,652	4,437,788	17,198,451
Projected Renewable and Nonemitting Energy	1,262,556	1,608,692	1,548,245	3,284,829	7,704,322
Net Retail Sales	2,818,516	2,642,248	2,880,407	1,152,958	9,494,129
Target Percentage	31%	38%	35%	74%	
Interim Clean Energy Target	1,262,556	1,608,692	1,548,245	3,284,829	7,704,322

Specific Actions

Note – The following specific actions are anticipated for the 2025 IRP final filing on March 31, 2025, but may not be available before that time:

- ***Supply-ide resource actions***
- ***Demand-side resource actions***

Customer Benefit Indicators

Note – The discussion regarding the current customer benefit indicators framework and how it is included in the development of the CEAP is anticipated for the 2025 IRP final filing on March 31, 2025, but may not be available before that time.

APPENDIX P – 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 = supply side resource (table)

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