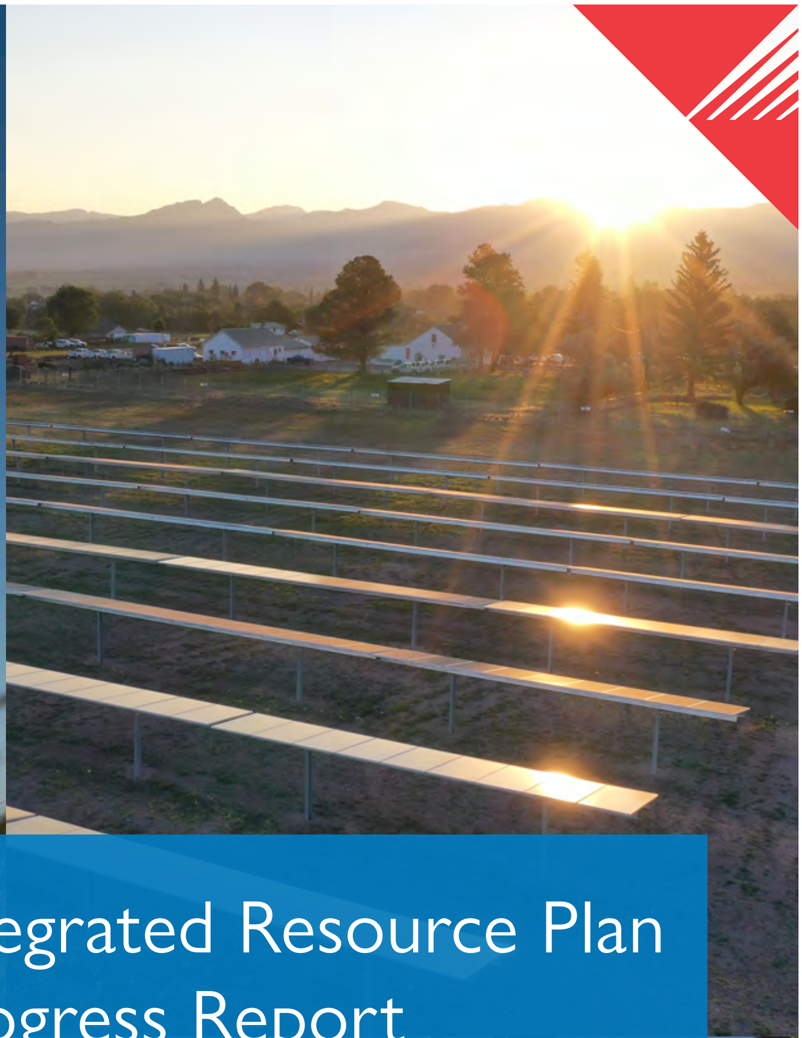

Washington 2021 Integrated Resource Plan
Two-Year Progress Report

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Also filed as "2023 Integrated Resource Plan"
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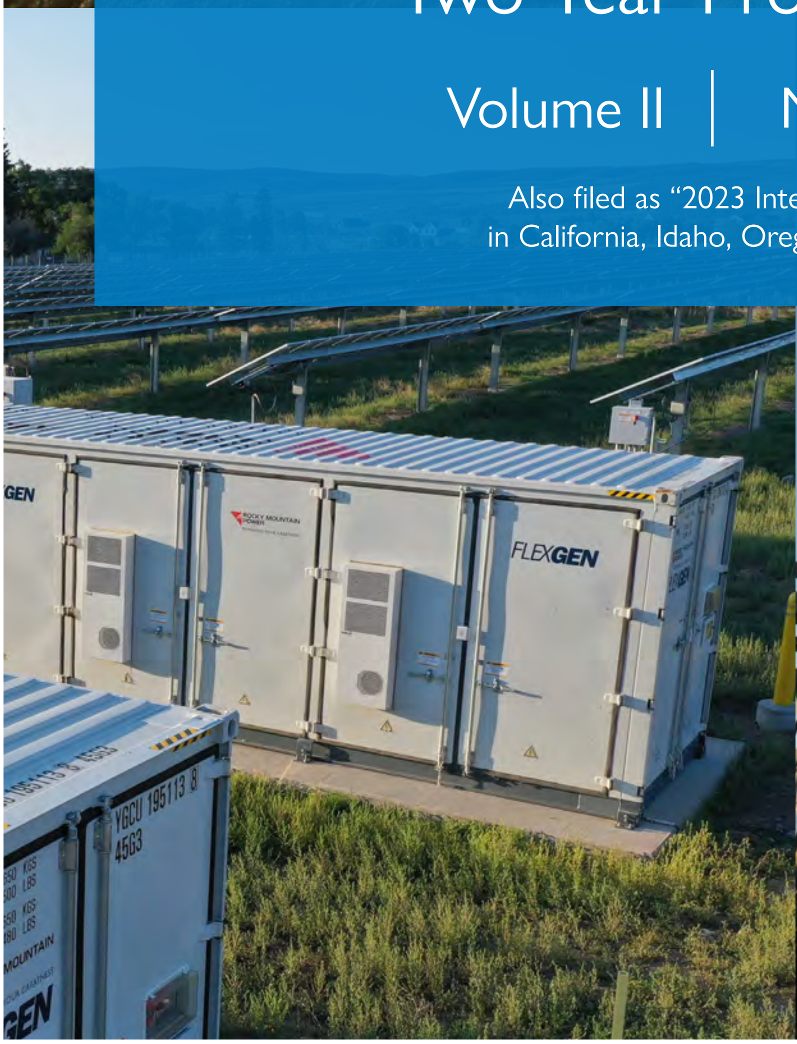
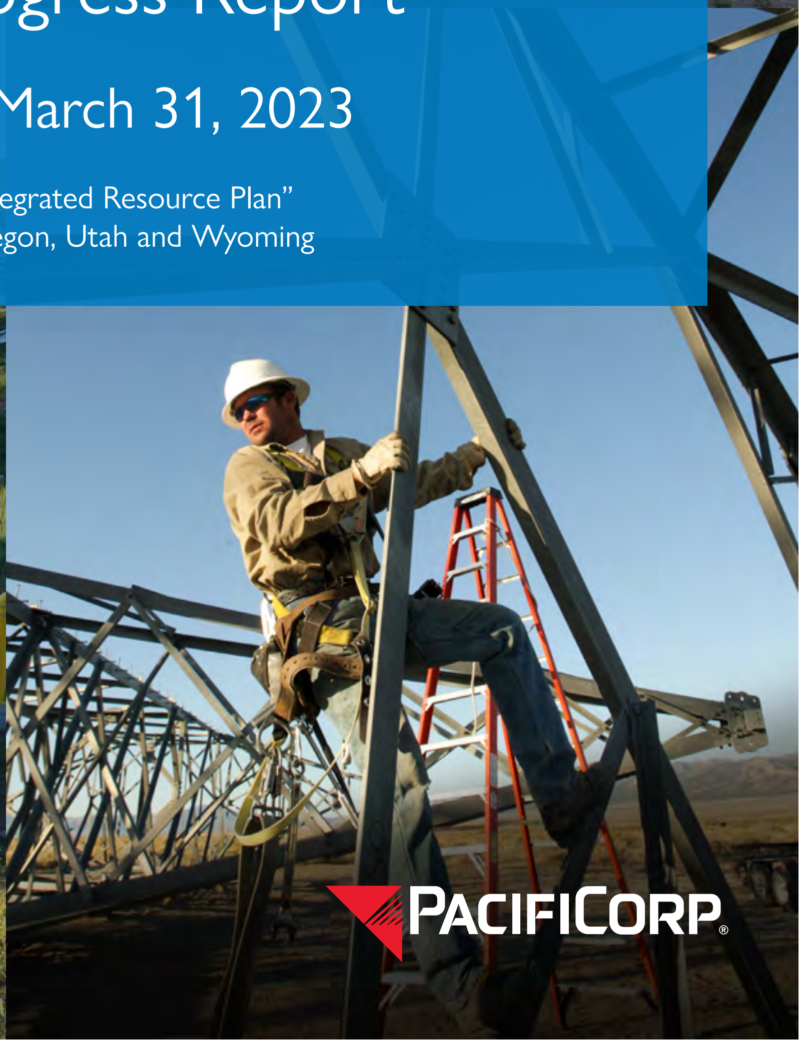




PACIFICORP

APPENDIX A – LOAD FORECAST

Introduction

This appendix reviews the load forecast used in the modeling and analysis of the 2023 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

The Company updated its load forecast in May 2022. The compound annual load growth rate for the 10-year period (2023 through 2032) is 2.69 percent. Relative to the load forecast prepared for the 2021 IRP, PacifiCorp's 2032 forecast load requirement increased in Oregon, Utah and Idaho, while PacifiCorp system load requirement increased 17.00 percent in 2032. Figure A.1 has a comparison of the load forecasts from the 2023 IRP to the 2021 IRP.

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

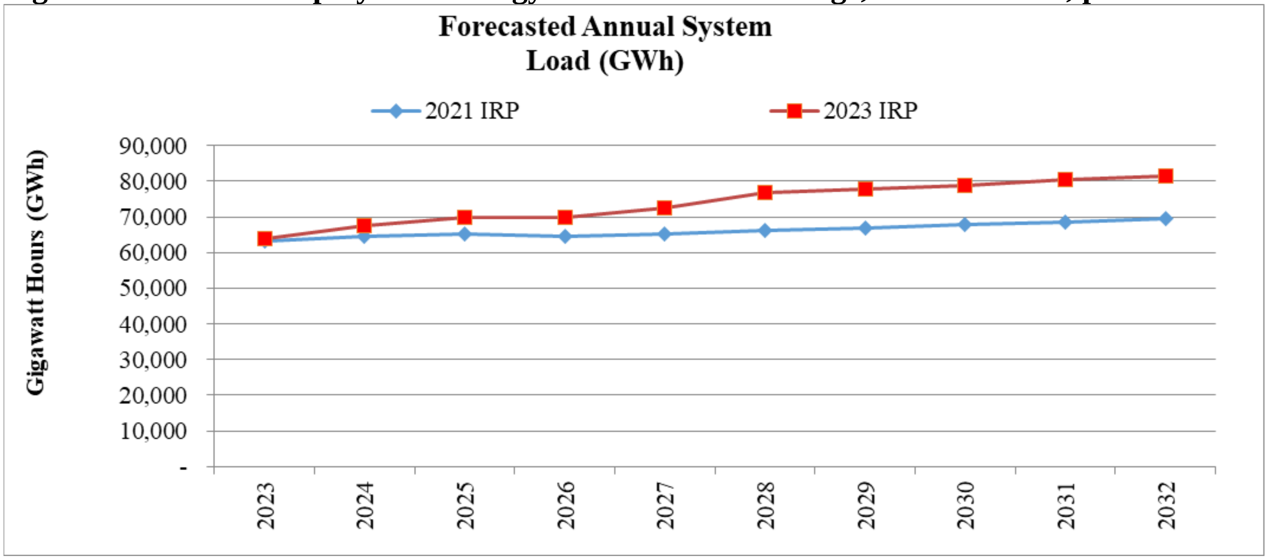


Table A.1 and Table A.2 show the annual load and coincident peak load forecast when not reducing load projections to account for new energy efficiency measures.[1] Tables A.3 and A.4 show the forecast changes relative to the 2021 IRP load forecast for loads and coincident system peak, respectively.

Table A.1 – Forecasted Annual Load, 2023 through 2032 (Megawatt-hours), at Generation, pre-DSM

Year	Total	OR	WA	CA	UT	WY	ID
2023	64,032,930	16,209,670	4,638,720	863,330	28,599,180	9,644,200	4,077,830
2024	67,499,270	18,374,450	4,692,110	861,560	29,740,030	9,763,560	4,067,560
2025	69,805,060	19,730,320	4,700,760	855,220	30,361,220	10,074,860	4,082,680
2026	69,938,420	20,457,650	4,721,760	852,970	29,687,480	10,113,240	4,105,320
2027	72,649,770	21,761,290	4,756,830	853,180	31,034,420	10,116,940	4,127,110
2028	76,681,120	23,445,960	4,811,200	856,480	33,183,740	10,229,110	4,154,630
2029	77,919,280	23,952,780	4,841,310	855,160	33,861,360	10,239,970	4,168,700
2030	78,811,840	24,066,060	4,885,350	855,790	34,483,900	10,332,550	4,188,190
2031	80,380,690	24,821,690	4,930,700	856,600	35,199,890	10,364,120	4,207,690
2032	81,321,780	25,160,880	4,990,400	859,960	35,600,350	10,476,730	4,233,460
Compound Annual Growth Rate							
2023-32	**2.69%**	**5.01%**	**0.82%**	**-0.04%**	**2.46%**	**0.92%**	**0.42%**

[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
2023	11,033	2,650	835	147	5,408	1,221	772
2024	11,427	2,833	846	147	5,537	1,295	770
2025	11,747	3,011	857	148	5,628	1,301	803
2026	11,758	3,054	871	148	5,572	1,305	808
2027	12,051	3,188	887	150	5,707	1,306	813
2028	12,485	3,323	905	151	5,993	1,317	794
2029	12,683	3,487	926	156	6,023	1,292	798
2030	12,815	3,507	946	158	6,101	1,301	803
2031	13,123	3,631	966	160	6,214	1,311	841
2032	13,209	3,632	985	161	6,268	1,316	847
Compound Annual Growth Rate							
2023-32	**2.02%**	**3.56%**	**1.86%**	**1.03%**	**1.65%**	**0.83%**	**1.03%**

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

Year	Total	OR	WA	CA	UT	WY	ID
2023	789,940	450,990	(17,310)	(19,170)	388,800	(112,270)	98,900
2024	3,047,960	2,268,330	(18,530)	(26,610)	947,850	(199,700)	76,620
2025	4,642,800	3,490,810	(29,480)	(33,670)	1,020,190	117,860	77,090
2026	5,411,390	4,038,830	(39,130)	(38,160)	1,334,560	33,730	81,560
2027	7,471,370	5,152,040	(39,360)	(39,230)	2,333,490	(23,110)	87,540
2028	10,597,700	6,589,320	(39,200)	(39,800)	3,990,880	1,290	95,210
2029	11,150,620	6,915,680	(38,590)	(40,210)	4,251,510	(38,250)	100,480
2030	11,088,630	6,798,020	(37,750)	(42,820)	4,328,150	(61,120)	104,150
2031	11,852,040	7,341,690	(27,480)	(42,960)	4,566,100	(101,550)	116,240
2032	11,814,570	7,448,410	(22,820)	(43,290)	4,388,360	(85,440)	129,350

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

Year	Total	OR	WA	CA	UT	WY	ID
2023	342	188	46	5	154	(58)	7
2024	620	353	50	6	211	(5)	5
2025	805	511	53	6	209	(2)	28
2026	891	540	61	7	264	(10)	29
2027	1,112	661	71	7	356	(15)	31
2028	1,441	784	82	8	568	(12)	12
2029	1,550	936	96	14	533	(43)	14
2030	1,577	945	108	16	538	(47)	17
2031	1,785	1,060	120	18	584	(45)	49

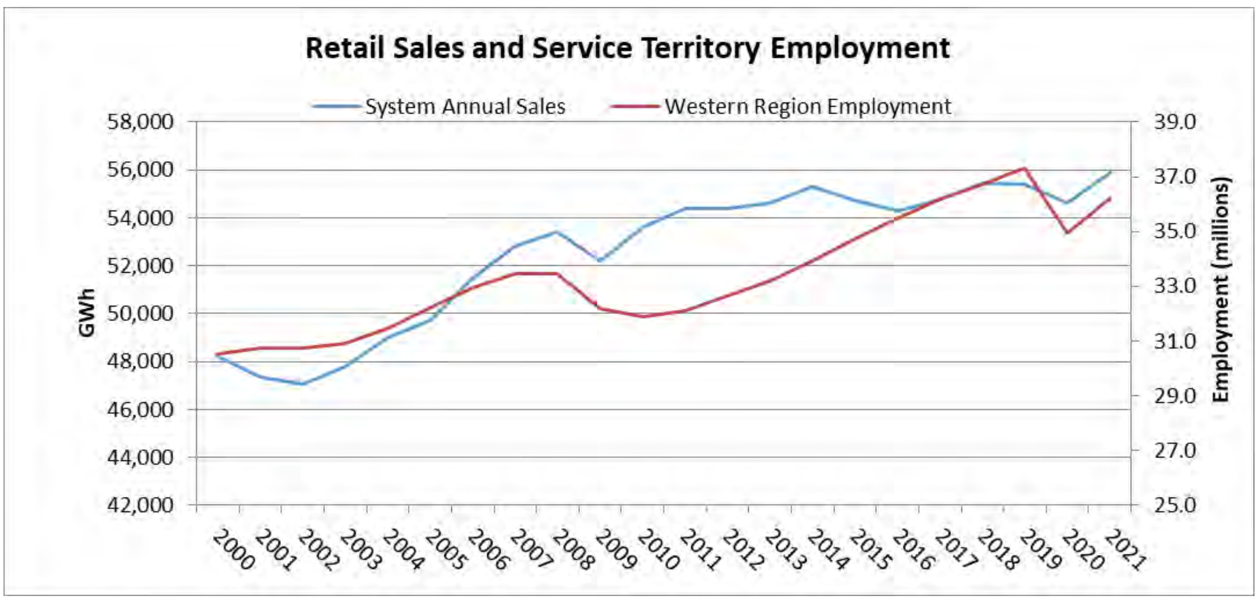
2032	1,807	1,077	133	19	572	(49)	56

Load Forecast Assumptions

Regional Economy by Jurisdiction

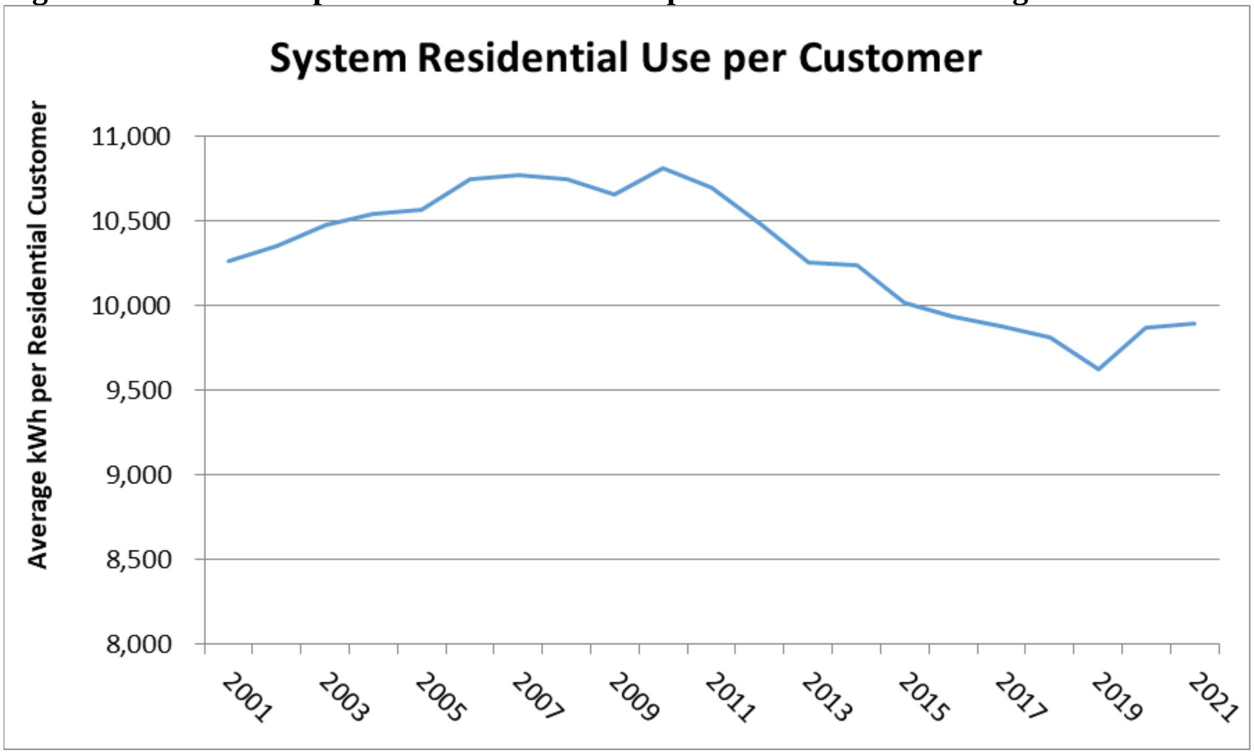
The PacifiCorp electric service territory is comprised of six states and within these states the Company serves customers in a total of 90 counties. The level of retail sales for each state and county is correlated with economic conditions and population statistics in each state. PacifiCorp uses both 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 2021, in Figure A.2, it is apparent that the Company'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 2023 IRP forecast utilizes the March 2022 release of IHS Markit economic driver forecast; whereas the 2021 IRP relied on the October 2019 release from IHS Markit. 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

The Company's load forecast is based on historical actual weather adjusted for expectations and impacts from climate change. The historical weather is defined by the 20-year period of 2002 through 2021. 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] The Company 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

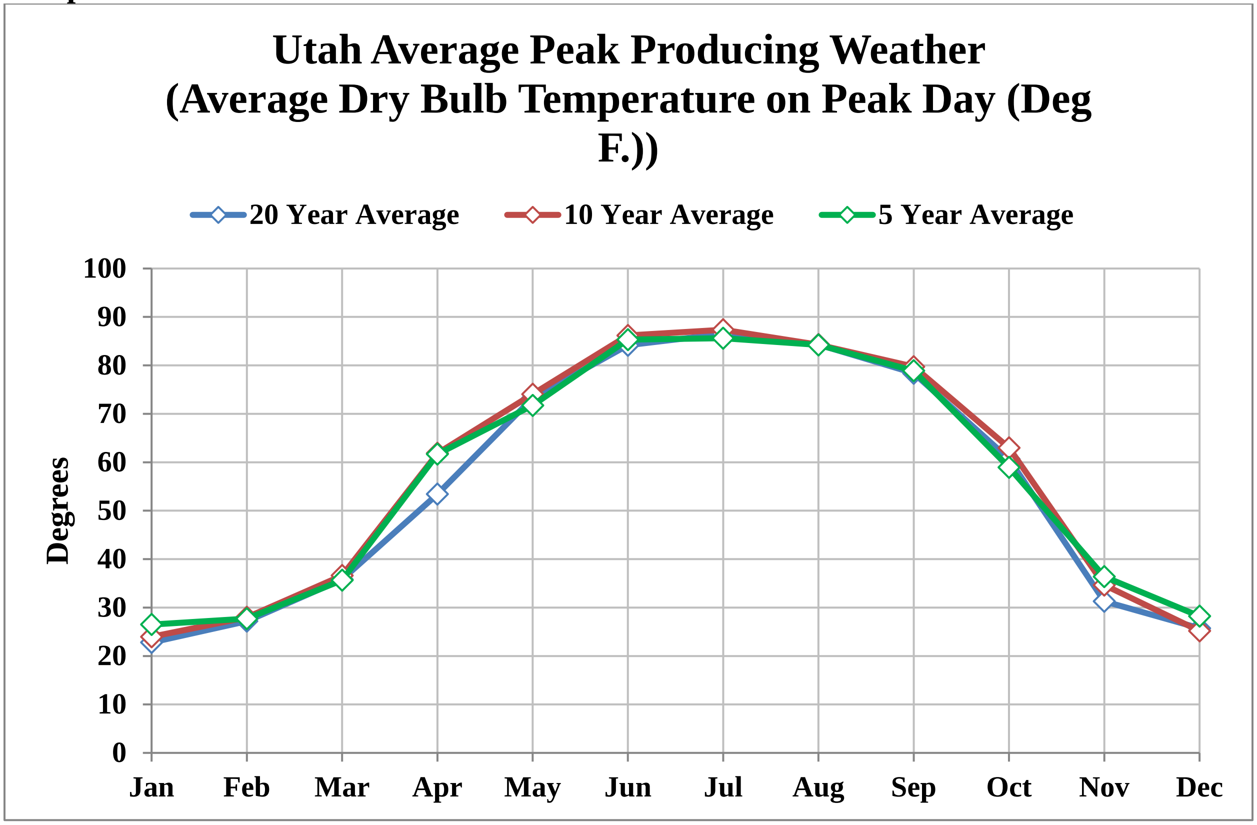
*Lower bound of temperature projections based on RCP 4.5, while upper bound based on RCP 8.5

In addition to climate change weather discussed above, the Company 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.

The Company also updated its temperature spline models to the five-year time period of October 2016 – September 2021. The Company'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")

The Company 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. The Company 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

The Company 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. Customer forecasts are provided by the customer to the Company through a regional business manager (“RBM”).

Actual Load Data

With the exception to the industrial class, the Company uses actual load data from January 2000 through February 2022. The historical data period used to develop the industrial monthly sales forecast is from January 2000 through February 2022 in Utah, Wyoming, and Washington, January 2002 through February 2022 in Idaho, and January 2003 through February 2022 in California and January 2008 through February 2022 in Oregon.

The following tables are the annual actual retail sales, non-coincident peak, and coincident peak by state used in calculating the 2023 IRP retail sales forecast.

Table A.6 – Weather Normalized Jurisdictional Retail Sales 2000 through 2021

System Retail Sales - Megawatt-hours (MWh)*							
Year	California	Idaho	Oregon	Utah	Washington	Wyoming	**System**
2000	770,820	3,116,508	13,850,006	18,970,364	4,084,537	7,411,248	**48,203,483**
2001	768,864	3,005,141	13,392,332	18,559,167	3,995,989	7,652,997	**47,374,489**
2002	791,735	3,256,168	12,957,060	18,630,359	3,992,241	7,429,503	**47,057,066**
2003	812,166	3,269,807	12,939,631	19,281,125	4,041,618	7,426,913	**47,771,259**
2004	835,515	3,333,624	13,058,719	19,892,658	4,073,666	7,793,618	**48,987,800**
2005	827,540	3,285,758	13,059,825	20,363,787	4,183,226	7,993,309	**49,713,446**
2006	848,726	3,346,052	13,774,581	21,187,643	4,108,566	8,209,339	**51,474,907**
2007	866,742	3,425,039	13,871,720	22,086,852	4,053,437	8,504,273	**52,808,062**
2008	857,500	3,444,347	13,135,644	22,715,811	4,052,529	9,203,352	**53,409,183**
2009	819,819	2,979,003	12,970,802	22,146,938	4,024,282	9,256,870	**52,197,714**
2010	835,326	3,468,573	13,046,266	22,590,597	4,023,412	9,648,267	**53,612,440**
2011	797,736	3,493,098	12,891,100	23,406,694	3,994,623	9,792,857	**54,376,107**
2012	776,608	3,543,173	12,902,817	23,692,760	4,017,534	9,469,443	**54,402,334**
2013	766,445	3,586,627	12,955,649	23,770,781	4,029,058	9,533,401	**54,641,961**
2014	763,083	3,574,849	13,044,614	24,245,893	4,074,243	9,587,020	**55,289,702**
2015	732,905	3,532,641	13,044,577	24,008,248	4,064,376	9,360,103	**54,742,851**
2016	745,142	3,495,674	13,203,510	23,655,727	4,012,667	9,191,271	**54,303,991**
2017	749,028	3,608,590	13,230,882	23,807,001	4,044,195	9,331,829	**54,771,525**
2018	733,383	3,641,048	13,190,422	24,586,138	4,030,934	9,243,563	**55,425,488**
2019	735,995	3,530,085	13,272,614	24,527,670	4,022,640	9,317,139	**55,406,143**
2020	755,926	3,596,981	13,179,949	24,703,889	4,074,386	8,317,048	**54,628,180**
2021	787,505	3,534,599	13,698,449	25,272,678	4,108,739	8,494,257	**55,896,227**
Compound Annual Growth Rate							
2000-21	**0.10%**	**0.60%**	**-0.05%**	**1.38%**	**0.03%**	**0.65%**	**0.71%**

*System retail sales do not include sales for resale

Table A.7 – Non-Coincident Jurisdictional Peak 2000 through 2021

Non-Coincident Peak - Megawatts (MW)*							
Year	California	Idaho	Oregon	Utah	Washington	Wyoming	**System**
2000	176	686	2,603	3,684	785	1,061	**8,995**
2001	162	616	2,739	3,480	755	1,124	**8,876**
2002	174	713	2,639	3,773	771	1,113	**9,184**
2003	169	722	2,451	4,004	788	1,126	**9,260**
2004	193	708	2,524	3,862	920	1,111	**9,317**
2005	189	753	2,721	4,081	844	1,224	**9,811**
2006	180	723	2,724	4,314	822	1,208	**9,970**
2007	187	789	2,856	4,571	834	1,230	**10,466**
2008	187	759	2,921	4,479	923	1,339	**10,609**
2009	193	688	3,121	4,404	917	1,383	**10,705**
2010	176	777	2,552	4,448	893	1,366	**10,213**
2011	177	770	2,686	4,596	854	1,404	**10,486**
2012	159	800	2,550	4,732	797	1,337	**10,376**
2013	182	814	2,980	5,091	886	1,398	**11,351**
2014	161	818	2,598	5,024	871	1,360	**10,831**
2015	157	843	2,598	5,226	837	1,326	**10,986**
2016	155	848	2,584	5,018	819	1,300	**10,724**
2017	177	830	2,920	4,932	943	1,354	**11,156**
2018	158	830	2,608	5,091	849	1,319	**10,854**
2019	151	793	2,632	5,158	895	1,363	**10,993**
2020	155	806	2,562	5,336	848	1,271	**10,979**
2021	149	771	2,894	5,547	938	1,299	**11,598**
Compound Annual Growth Rate							
2000-21	**-0.77%**	**0.56%**	**0.51%**	**1.97%**	**0.85%**	**0.96%**	**1.22%**

*Non-coincident peaks do not include sales for resale

Table A.8 – Jurisdictional Contribution to Coincident Peak 2000 through 2021

Coincident Peak - Megawatts (MW)*							
Year	California	Idaho	Oregon	Utah	Washington	Wyoming	**System**
2000	154	523	2,347	3,684	756	979	**8,443**
2001	124	421	2,121	3,479	627	1,091	**7,863**
2002	162	689	2,138	3,721	758	1,043	**8,511**
2003	155	573	2,359	4,004	774	1,022	**8,887**
2004	120	603	2,200	3,831	740	1,094	**8,588**
2005	171	681	2,238	4,015	708	1,081	**8,895**
2006	156	561	2,684	3,972	816	1,094	**9,283**
2007	160	701	2,604	4,381	754	1,129	**9,730**

2008	171	682	2,521	4,145	728	1,208	**9,456**
2009	153	517	2,573	4,351	795	987	**9,375**
2010	144	527	2,442	4,294	757	1,208	**9,373**
2011	143	549	2,187	4,596	707	1,204	**9,387**
2012	156	782	2,163	4,731	749	1,225	**9,806**
2013	156	674	2,407	5,091	797	1,349	**10,474**
2014	150	630	2,345	5,024	819	1,294	**10,263**
2015	152	805	2,472	5,081	833	1,259	**10,601**
2016	139	575	2,462	4,940	817	1,201	**10,135**
2017	152	593	2,547	4,911	787	1,306	**10,296**
2018	126	741	2,526	5,037	790	1,295	**10,514**
2019	122	731	2,276	5,158	761	1,248	**10,297**
2020	127	603	2,428	5,336	839	1,180	**10,515**
2021	145	767	2,543	5,319	839	1,214	**10,827**
Compound Annual Growth Rate							
2000-21	**-0.29%**	**1.84%**	**0.38%**	**1.76%**	**0.50%**	**1.03%**	**1.19%**

*Coincident peaks do not include sales for resale

System Losses

Line loss factors are derived using the five-year average of the percent difference between the annual system load by jurisdiction and the retail sales by jurisdiction. System line losses were updated to reflect actual losses for the five-year period ending December 31, 2021.

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 Company's 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 2000 to February 2022. For the residential class, the Company forecasts the number of customers using IHS Markit's forecast of each state's population or number of households as the major driver.

The Company 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.

The Company 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, the Company 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 the Company'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, in which an Industrial Production Index is used. For a small number of the very largest industrial customers, the Company prepares individual forecasts based on input from the customer and information provided by the RBM's.

After the Company 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 peak loads 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, the Company 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 2002 through 2021, 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 2023 IRP portfolio development includes the Company'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.

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, the Company 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. The Company 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.

The load forecast also incorporates the Company'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. The Company's building electrification forecast is based on expected fuel shares for space heating and water heating equipment at the end of its useful life and future new construction shares of electric fuel for these end-uses over time. Adoption curves are calibrated to expected equipment turnover and new construction rates in alignment with assumptions used in the Conservation Potential Assessment. Adoption curves and timing of building electrification is estimated based on the state specific policies or known market trends supporting advancement of building electrification.

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

Sales Forecast at the Customer Meter

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

Table A.9 – System Annual Retail Sales Forecast 2021 through 2032, post-DSM

System Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2023	17,361,583	20,978,789	18,760,385	1,472,103	98,858	**58,671,719**
2024	17,561,027	23,333,643	18,912,628	1,463,717	95,519	**61,366,533**
2025	17,663,790	24,565,976	19,192,595	1,455,086	92,615	**62,970,063**
2026	17,860,209	25,344,020	17,755,233	1,449,220	90,685	**62,499,366**
2027	18,075,462	27,203,257	17,720,663	1,442,125	89,172	**64,530,679**
2028	18,386,033	30,063,031	17,769,947	1,434,670	88,119	**67,741,799**
2029	18,633,432	30,372,554	17,700,916	1,426,506	86,618	**68,220,026**
2030	18,972,662	30,145,257	17,751,969	1,419,207	85,392	**68,374,488**
2031	19,332,679	30,522,754	17,739,953	1,412,108	84,220	**69,091,714**
2032	19,852,639	30,155,847	17,782,332	1,403,445	83,419	**69,277,682**
Compound Annual Growth Rate						
2023-32	1.50%	4.11%	-0.59%	-0.53%	-1.87%	1.86%

Residential

The average annual growth of the residential class sales forecast increased from 0.80 percent in the 2021 IRP to 1.50 percent in the 2023 IRP. The number of residential customers across PacifiCorp's system is expected to grow at an annual average rate of 1.48 percent, reaching approximately 2.06 million customers in 2032, with Rocky Mountain Power states adding 1.82 percent per year and Pacific Power states adding 0.92 percent per year.

Commercial

Average annual growth of the commercial class sales forecast increased from 1.04 percent annual average growth in the 2021 IRP to 4.11 percent in the 2023 IRP. The number of commercial customers across PacifiCorp's system is expected to grow at an annual average rate of 0.90 percent, reaching approximately 246,000 customers in 2032, with Rocky Mountain Power states adding 1.18 percent per year and Pacific Power states adding 0.52 percent per year.

Industrial

Average annual growth of the industrial class sales forecast decreased from -0.11 percent annual average growth in the 2021 IRP to -0.59 percent expected annual growth in the 2023 IRP. A portion of the Company's industrial load is in the extractive industry in Utah and Wyoming; therefore, changes in commodity prices can impact the Company's load forecast.

State Summaries

Oregon

Table A.10 – Forecasted Retail Sales Growth in Oregon, post-DSM summarizes Oregon state forecasted retail sales growth by customer class.

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

Oregon Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2023	5,776,140	6,971,569	1,458,214	270,754	29,920	14,506,597
2024	5,813,544	8,727,403	1,466,594	270,264	29,236	16,307,041
2025	5,806,005	9,761,216	1,495,283	269,413	28,514	17,360,433
2026	5,840,308	10,246,092	1,489,796	269,210	28,009	17,873,416
2027	5,887,124	11,251,088	1,475,161	268,963	27,619	18,909,955
2028	5,974,783	12,561,821	1,461,575	268,836	27,405	20,294,420
2029	6,054,951	12,820,090	1,455,444	268,381	27,108	20,625,973
2030	6,172,566	12,677,326	1,453,566	268,029	26,950	20,598,436
2031	6,314,070	13,084,453	1,459,414	267,642	26,835	21,152,414
2032	6,495,531	13,089,511	1,476,758	267,370	26,832	21,356,002
Compound Annual Growth Rate						
2023-32	**1.31%**	**7.25%**	**0.14%**	**-0.14%**	**-1.20%**	**4.39%**

Washington

Table A.11 – Forecasted Retail Sales Growth in Washington, post-DSM summarizes Washington state forecasted retail sales growth by customer class.

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

Washington Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2023	1,569,912	1,569,506	828,111	161,366	3,294	**4,132,188**
2024	1,575,457	1,581,008	825,124	159,738	3,231	**4,144,559**
2025	1,566,405	1,568,866	812,588	158,750	3,199	**4,109,809**
2026	1,566,847	1,564,706	802,531	158,297	3,192	**4,095,573**
2027	1,567,629	1,565,138	796,393	157,806	3,190	**4,090,156**
2028	1,575,315	1,567,825	794,158	157,247	3,200	**4,097,744**
2029	1,574,971	1,559,991	789,614	156,835	3,190	**4,084,601**
2030	1,580,219	1,556,026	787,560	156,474	3,190	**4,083,470**
2031	1,585,479	1,555,833	787,983	156,415	3,190	**4,088,900**
2032	1,596,353	1,556,759	788,347	156,000	3,199	**4,100,658**
Compound Annual Growth Rate						
2023-32	**0.19%**	**-0.09%**	**-0.55%**	**-0.38%**	**-0.32%**	**-0.09%**

California

Table A.12 - Forecasted Retail Sales Growth in California, post-DSM summarizes California state forecasted sales growth by customer class.

Table A.6 - Forecasted Retail Sales Growth in California, post-DSM

California Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2023	377,233	238,946	54,997	97,232	1,628	770,037
2024	377,131	237,264	53,389	96,630	1,600	766,014
2025	374,277	233,240	52,235	96,229	1,569	757,549
2026	372,480	230,331	51,812	96,016	1,549	752,188
2027	370,942	228,808	51,440	95,783	1,534	748,507
2028	370,818	227,945	51,185	95,583	1,527	747,058
2029	368,319	225,742	50,735	95,268	1,515	741,578
2030	366,926	224,681	50,478	95,019	1,509	738,613
2031	365,606	223,441	50,232	94,649	1,504	735,432
2032	365,968	223,270	50,189	94,220	1,506	735,153
Compound Annual Growth Rate						
2023-32	**-0.34%**	**-0.75%**	**-1.01%**	**-0.35%**	**-0.86%**	**-0.51%**

Utah

Table A.13 – Forecasted Retail Sales Growth in Utah, post-DSM summarizes Utah state forecasted sales growth by customer class.

Table A.7 – Forecasted Retail Sales Growth in Utah, post-DSM

Utah Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2023	7,835,131	10,246,229	8,137,068	233,429	49,506	26,501,364
2024	7,986,696	10,832,402	8,238,305	230,300	47,036	27,334,739
2025	8,119,480	11,064,958	8,233,901	227,009	45,163	27,690,511
2026	8,284,098	11,384,983	6,807,862	223,609	44,067	26,744,620
2027	8,454,824	12,261,214	6,827,830	219,645	43,400	27,806,913
2028	8,665,353	13,820,108	6,843,943	215,282	43,126	29,587,812
2029	8,844,710	13,908,034	6,817,082	210,766	42,770	29,823,362
2030	9,066,276	13,850,077	6,834,566	206,189	42,633	29,999,741
2031	9,287,214	13,845,537	6,834,089	201,514	42,554	30,210,908
2032	9,613,627	13,483,845	6,814,215	195,865	42,630	30,150,181
Compound Annual Growth Rate						
2023-32	**2.30%**	**3.10%**	**-1.95%**	**-1.93%**	**-1.65%**	**1.44%**

Idaho

Table A.14 - Forecasted Retail Sales Growth in Idaho, post-DSM summarizes Idaho state forecasted sales growth by customer class.

Table A.8 - Forecasted Retail Sales Growth in Idaho, post-DSM

Idaho Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2023	793,909	551,520	1,770,789	679,642	2,641	3,798,500
2024	804,094	554,572	1,736,293	677,301	2,625	3,774,885
2025	806,682	552,218	1,736,660	674,431	2,594	3,772,585
2026	811,343	549,260	1,735,986	672,973	2,571	3,772,133
2027	815,138	545,183	1,734,061	670,967	2,547	3,767,897
2028	820,769	542,345	1,732,080	668,926	2,531	3,766,652
2029	819,247	534,579	1,728,504	666,588	2,502	3,751,419
2030	820,297	527,445	1,726,072	664,917	2,480	3,741,211
2031	820,173	519,098	1,724,099	663,366	2,460	3,729,196
2032	823,076	514,464	1,722,624	661,563	2,447	3,724,174
Compound Annual Growth Rate						
2023-32	**0.40%**	**-0.77%**	**-0.31%**	**-0.30%**	**-0.84%**	**-0.22%**

Wyoming

Table A.15 – Forecasted Retail Sales Growth in Wyoming, post-DSM summarizes Wyoming state forecasted sales growth by customer class.

Table A.9 – Forecasted Retail Sales Growth in Wyoming, post-DSM

Wyoming Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2023	1,009,258	1,401,020	6,511,205	29,679	11,870	8,963,032
2024	1,004,104	1,400,993	6,592,922	29,485	11,791	9,039,295
2025	990,941	1,385,479	6,861,929	29,252	11,575	9,279,176
2026	985,132	1,368,647	6,867,245	29,115	11,297	9,261,436
2027	979,805	1,351,827	6,835,777	28,961	10,882	9,207,251
2028	978,994	1,342,988	6,887,006	28,797	10,329	9,248,113
2029	971,235	1,324,118	6,859,538	28,668	9,534	9,193,092
2030	966,378	1,309,701	6,899,728	28,579	8,631	9,213,017
2031	960,137	1,294,392	6,884,136	28,522	7,676	9,174,863
2032	958,085	1,287,998	6,930,199	28,427	6,805	9,211,514
Compound Annual Growth Rate						
2023-32	**-0.58%**	**-0.93%**	**0.70%**	**-0.48%**	**-5.99%**	**0.30%**

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.

The May 2022 forecast is the baseline scenario. For the high and low load growth scenarios, optimistic and pessimistic economic driver assumptions from IHS Markit were applied to the economic drivers in the Company'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. Lastly, the high scenario incorporates the Company's low private generation forecast, while the low scenario incorporates the high private generation forecast.

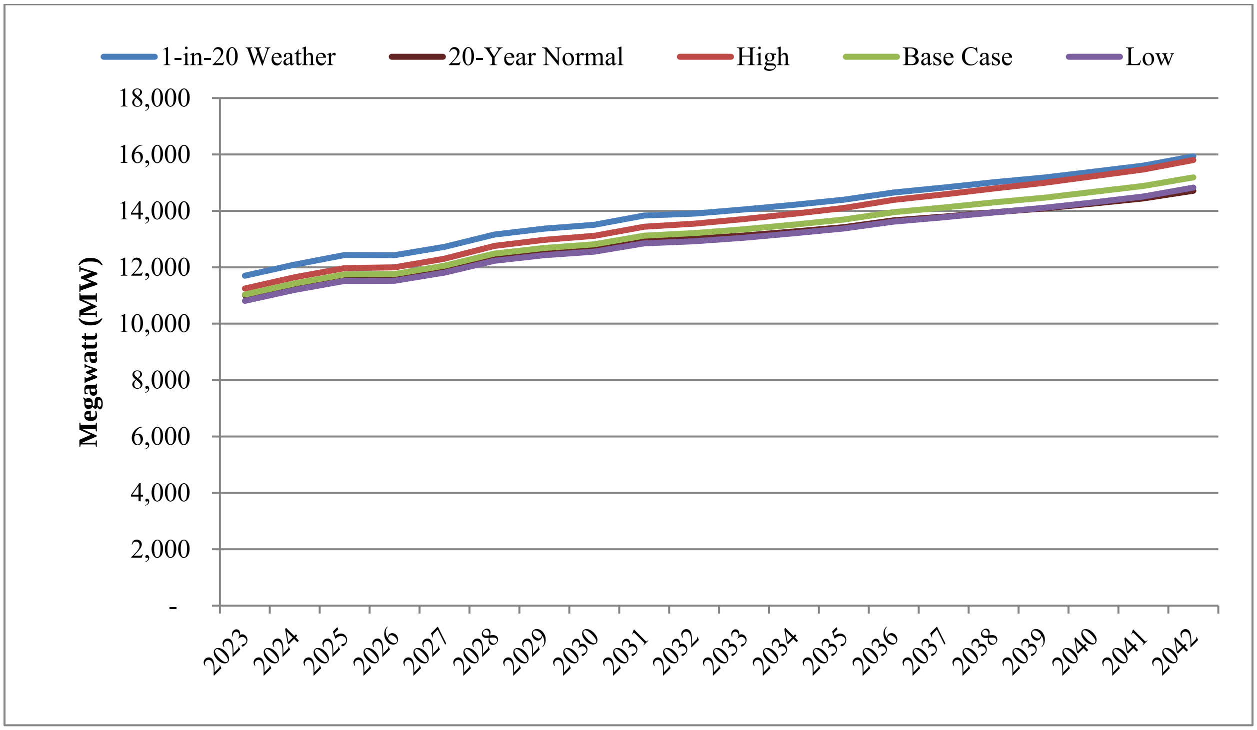
The 95% prediction interval is calculated at the system level and then allocated to each state and class based on their contribution to the variability of the system level forecast. The standard error bands for the jurisdictional peak forecasts were calculated in a similar manner. The final high load 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.

For the 1-in-20 year (5 percent probability) extreme weather scenario, the Company 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.

The 20-year normal scenario is based on normal weather, which is defined by the 20-year time period of 2002 through 2021 (50^{th} percentile). In prior IRP cycles, this scenario is what was traditionally used as the base IRP load forecast.

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

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



APPENDIX B - REGULATORY COMPLIANCE

Introduction

This appendix describes how PacifiCorp's 2023 Integrated Resource Plan (IRP) complies with (1) the various state commission IRP standards and guidelines, (2) specific analytical requirements stemming from acknowledgment orders for the company's 2021 Integrated Resource Plan, and other ongoing IRP acknowledgement order requirements as applicable, and (3) state commission IRP requirements stemming from other regulatory proceedings.

Included in this appendix are the following tables:

- Table B.1 - Provides an overview and comparison of the rules in each state for which IRP submission is required.[33]
- Table B.2 - Provides a description of how PacifiCorp addressed the 2021 IRP acknowledgement order requirements and other commission directives.
- Table B.3 - Provides an explanation of how this plan addresses each of the items contained in the Oregon IRP guidelines.
- Table B.4 - Provides an explanation of how this plan addresses each of the items contained in the Public Service Commission of Utah IRP Standard and Guidelines issued in June 1992.
- Table B.5 - Provides an explanation of how this plan addresses each of the items contained in the Washington Utilities and Transportation Commission IRP rules issued in December 2020 in WAC 480-100-620.
- Table B.6 - Provides an explanation of how this plan addresses each of the items contained in the Wyoming Public Service Commission IRP guidelines updated in March 2016.

General Compliance

PacifiCorp prepares the IRP on a biennial basis and files the IRP with state commissions. The preparation of the IRP is done in an open public process with consultation from all interested parties, including commissioners and commission staff, customers, and other stakeholders. This open process 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 will be described in Volume I, Chapter 2 (Introduction), as well as Volume II, Appendix C (Public) Input fully complies with IRP standards and guidelines.

[33] 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.

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 reasonably 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 – Modeling and Portfolio Evaluation.

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

Consistent with the IRP standards and guidelines of Oregon, Utah, and Washington, this IRP 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 2021 IRP.

The 2023 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.

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.

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)*

[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).*

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.

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

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

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.

Table B.1 provides detail on how this plan addresses the rule requirements.

> ***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. 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). 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. Note, however, that Rate Plan legislation allows pre-approval of near-term resource investments.	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.

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.	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.
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		

Table B.2 – Handling of 2021 IRP Acknowledgment and Other IRP Requirements

Reference	IRP Requirement or Recommendation	How the Guideline is Addressed in the 2023 IRP
Idaho		
Order No. 35514 p. 17	We direct the Company, in its next IRP, to clarify whether a LOLH reliability target of 2.4 hours per year was achieved by the Company's portfolios and explain the development of FOT availability limits.	Because of limitations on computing power, the Company has not performed detailed hourly stochastic analysis so as to precisely determine the reliability of each of its portfolios. For reference, due to the complexity of the Company's portfolio and system operations, running one year of one study through 50 iterations could take a single computer upwards of a week. The Company's reliability assessment is intended to ensure that each portfolio achieves a comparable level of reliability. Because each study measures availability against requirements in every hour during the reliability assessment, all portfolios will logically achieve comparable reliability. Further, ENS measures support that this is the case. Discussion of the Company's FOT availability limits is provided in Chapter 5 (Reliability and Resiliency).
Order No. 35514 p. 17	We further direct the Company to clarify the issue of exceedance of FOT limits in the early years of the planning horizon as it pertains to the first deficit date for purposes of PURPA avoided cost rates and whether the inclusion of three percent contingency amounts for firm purchases were appropriate to include to meet Company load.	A discussion of exceedances in the first several years is provided in Chapter 5 (Reliability and Resiliency). Such exceedances are unavoidable as the Company pursues sufficient resources to reduce market reliance of the 20-year planning period. In actual operations, PacifiCorp must balance the risk of higher reliance on market purchases against the cost of procuring from a limited pool of resource options available in the very near term, rather than from a larger pool of resource options available in the next few years. That balancing will be a key consideration in PacifiCorp's ongoing 2022 All-Source Request for Proposals. As a result, forthcoming developments may be more pertinent to the question of deficit dates than the 2023 IRP itself. As detailed in Volume II, Appendix F (Flexible Reserve Study), to the extent the PacifiCorp's firm market purchases come from entities in other balancing authority areas, those entities will cover the contingency reserve obligation on the generation used to support the sale, and PacifiCorp's contingency reserve obligation will be reduced relative to what it would have been had it used its own generation to serve that portion of its load.

Order No. 35514 p. 17	While we understand the market realities of natural gas, we encourage the Company to continue exploring an approach in its IRP process that allows for a reasonable and accurate selection of cost-effective natural gas resources in a portfolio.	PacifiCorp has included natural gas in its resource options per the supply-side resource table as developed throughout the public input meeting process. New gas options were not selected in the least-cost, least-risk methodology to develop the final preferred portfolio. PacifiCorp recognizes that many non-emitting technologies require technological progress to achieve the capabilities and costs assumed in the 2023 IRP, and will continue to consider technologies that are presently available. Because the Inflation Reduction Act provides tax credits only for non-emitting resources, gradually transitioning a new resource to a non-emitting fuel comes at a significant cost. See Volume I, Chapter 7 (Resource Options).
Order No. 35514 p. 17	Finally, we acknowledge the inherent complexities with the Natrium project and direct the Company to continue to assess the risks of technology viability and potential delays with Natrium and plan accordingly.	In this cycle, Natrium is anticipated to come online in the summer of 2030. The 2023 IRP includes two "no nuclear" variant studies as described in Chapters 8 and 9, designed to inform alternative path analysis and potential costs and benefits. PacifiCorp continues to evaluate nuclear resources within the context of an evolving planning environment.

Reference	IRP Requirement or Recommendation	How the Guideline is Addressed in the 2023 IRP
Oregon		
Order No. 22-178, p. 7	Require PacifiCorp to perform additional and more varied analyses regarding Jim Bridger Units 3 and 4, including a no minimum take analysis as suggested by Staff and Sierra Club and an analysis of endogenous retirement dates frequent enough to approximately match Staffs suggestion of allowing for retirement every two years.	In the 2023 IRP, retirements are optimized in every available year. As communicated during the 2023 public input meeting series and in response to feedback, no minimum take assumptions were assumed in Plexos modeling beyond present contracts. For Jim Bridger 3 and 4 this means the complete removal of minimum take provisions.
Order No. 22-178, p. 7	PacifiCorp is directed to file an updated long-term fuel plan for Jim Bridger with its 2023 IRP.	On March 28, 2023, the Commission granted PacifiCorp's request for an extension of time to submit the updated long-term fuel plan for Jim Bridger on May 31, 2023.
Order No. 22-178, p. 10	Consider how to ensure PacifiCorp has a complete and balanced portfolio given the current posture of the Natrium project.	In this cycle, Natrium is anticipated to come online in the summer of 2030. The 2023 IRP includes two "no nuclear" variant studies as described in Volume I, Chapters 8 and 9, designed to inform alternative path analysis and potential costs and benefits. PacifiCorp continues to evaluate nuclear resources within the context of an evolving planning environment.

Order No. 22-178, p. 11	In future IRPs, we expect PacifiCorp to articulate clearer justifications for its transmission projects, including how the company assessed transmission needs and alternatives comprehensively, how and why a particular project was selected in a transmission planning process, why it is reasonable for ratepayers to pay substantial costs for these particular projects, and what quantifiable (and quantified) and non-quantifiable (but valued qualitatively) benefits will come to Oregon ratepayers in particular and PacifiCorp ratepayers in general, as compared with benefits from regional projects that accrue to other regional actors not contributing to costs.	For the 2023 IRP, PacifiCorp evaluated transmission options based on the three cluster study outcomes completed thus far, as well as other analysis for locations not well-represented in the cluster study process. This represents the best available information regarding potential costs and resources. The addition of surplus and flexible hybrid resource options specifically allows the model to avoid transmission costs while increasing net generating capability at a given location using proportions of different technologies that are appropriate to a location and the needs of the portfolio as a whole. These options were modeled endogenously and in competition with a wide array of resources as detailed in multiple public input meetings. See Volume I, Chapter 4 (Transmission), and Volume I, Chapter 8 (Modeling and Portfolio Evaluation).
Order No. 22-178, p. 12	We also expect PacifiCorp to produce the full cost information for the [transmission] projects we acknowledge today in the rate cases where it seeks to place them into rate base.	PacifiCorp is committed to giving full accounting in its rate case proceedings. For the 2023 IRP, summary cost information is provided in Volume I, Chapter 1 (Executive Summary), and expanded cost information is provided in workpapers.
Order No. 22-178, p. 13	In order to connect new resources to the grid, it is critical not only that transmission be built, but that the right transmission be built; the Commission and stakeholders need to have sufficient information to verify that ratepayers are getting the benefits they are paying for at each stage of development. Going forward, we expect PacifiCorp to provide information that allows that assessment at the outset. We also expect the company to actively encourage key stakeholders like Commission Staff and consumer advocates to participate and provide a larger window into its own transmission planning processes.	IRP modeling accounts for cost, location, total transfer capability and resource enabled by transmission options. Options are modeled endogenously, and selections are driven primarily by the need to increase interconnection to allow efficient system transfer and to serve load. In the 2023 IRP, costs, descriptions, and transfer capabilities are defined, and in addition near-term transfer options are rooted in cluster study and queue analysis and informed by surplus resource options which allow for transmission costs to be avoided where appropriate. The transmission option modeling strategy was discussed at three public input meetings spanning June 2022 through February 2023 with opportunities for feedback and recommendations. Also, modeling of scale renewable resources for Oregon's CEP assumes there are no accompanying transmission requirements, providing an additional opportunity to evaluate transmission avoidance beyond the native core functionality of the Plexos model. See Volume I, Chapter 4 (Transmission), and Volume I, Chapter 8 (Modeling and Portfolio Evaluation).

Order No. 22-178, p. 14	We direct PacifiCorp to forecast a likely QF contract renewal rate. Because PacifiCorp operates in a multi-state footprint, we understand this assessment to be more complicated than an Oregon-only renewal rate. However, PacifiCorp should use historical renewable rates as well as other relevant information in its possession and attempt to make its forecast as accurate as possible.	PacifiCorp used an analysis of historical rates to establish a 79% renewal rate, which was implemented in the 2023 IRP and presented at the September 1-2, 2022 public input meeting. The analysis can be viewed at this web link: https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2023-irp/QF_Extension_History_2012-2017-2022.xlsx. For the purpose of modeling in the 2023 IRP, each QF was assumed to have a 79% chance of renewing, so it is reduced to 79% of its current size upon reaching its current expiration date and then continues indefinitely.
Order No. 22-178, p. 14; Appx B p. 1	Develop and run a sensitivity that considers locations or online dates for large, flexible loads such as hydrogen electrolysis within the 2023 IRP. The parameters of the study would be further discussed in the 2023 IRP process. Such a sensitivity would consider optimal locations and years to include large amounts of highly flexible load, throughout the planning timeframe. We adopt this recommendation and note that there may be additional large loads, such as data centers, that fall under this recommendation too.	See Volume II, Appendix N: (Energy Storage Potential Evaluation) for analysis of potential hydrogen electrolysis load opportunities. PacifiCorp would note that with expected transmission builds and the sizeable quantity of energy storage on its system in the preferred portfolio, the difference in marginal prices by location is relatively small. While co-locating hydrogen electrolysis with renewable generation may have some benefits, it may be outweighed by the costs of transporting hydrogen to end users. In addition, the potential for flexible load is also represented in part through stochastic load variation and through seven load-related sensitivities. In addition to the 2023 IRP's four core load sensitivities (High load, Low Load, 1 in 20 Load and 20-year Normal Load) and two load-related sensitivities (High Private generation and Low Private Generation), PacifiCorp has also added a "New Load" sensitivity which contemplates an unanticipated large load addition to understand the impacts of such an occurrence. See Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection Results). PacifiCorp continues to evaluate how to usefully model larger amounts of flexible load.
Order No. 22-178, p. 15; Appx B p. 1	PacifiCorp to conduct a stakeholder process to determine what source the cost data in the 2023 IRP will rely on.	PacifiCorp's initial cost assumptions were provided at a workshop held on September 2, 2022 as part of its public input process. In addition, stakeholders participated in the decision to model offshore wind and associated transmission on a linear basis where any amount of a 1000 MW project could be selected assuming PacifiCorp could participate in partnership with other utilities. The decision was also made to allow other resources to compete for usage of the land-based transmission system upgrades necessary to enable offshore wind. An offshore wind counterfactual study was also run to determine the magnitude of the costs and benefits of offshore wind. See Volume I, Chapters 8 and 9.

Order No. 22-178, p. 15; Appx B p. 1	We expect PacifiCorp to engage in the company's local transmission planning process as appropriate and to request that sufficient information to inform consideration of offshore wind in future IRPs is made available in this local transmission study cycle.	PacifiCorp completed an Economic Study Request ("ESR"), submitted by the Oregon Public Utility Commission ("OPUC") Staff March 2022 to have PacifiCorp evaluate the effects of 1.0 GW of Offshore Wind (OSW) generation in southern Oregon, assumed to be interconnected to PacifiCorp's Del Norte substation located in Del Norte, California.
Order No. 22-178, p. 15; Appx B p. 2	PacifiCorp to review its pumped hydro proposals as part of its 2023 IRP public workshop series. PacifiCorp will perform a variety of analyses regarding pumped storage hydro … including a careful comparison with other possible pumped storage hydro projects, in the 2023 IRP … [and] sufficient information to be able to conclude that PacifiCorp has considered resources other than its own in this process.	The 2023 IRP considered seven proxy pumped hydro resource locations across the system. All seven use identical cost and size characteristics appropriate for proxy modeling, and cover at minimum four projects unassociated with PacifiCorp. As modeled, none of the projects are actual, and the Company is not modeling its own projects. Instead, the 2023 IRP represents pumped hydro storage as proxy resources. Every endogenous model run considers the selection of any or all of these resources among the multitude of competing options. Whether selected or not, pumped hydro projects are eligible to bid into PacifiCorp's all-source RFPs where determinations of which projects are contracted is decided by additional agnostic modeling of actual bids, potentially both benchmarks and market bids.
Order No. 22-178, p. 16; Appx B p. 2	In places where there are inconsistencies between the WRAP and the approach the IRP takes … we direct that the reasons for any discrepancies be explained by PacifiCorp.	The Western Resource Adequacy Program (WRAP) uses a series of Effective Load Carrying Capability (ELCC) analyses to identify the aggregate capacity contribution of wind, solar, and run-of-river hydro. Attribution of capacity to individual resources is based, in part, on a resource's generation during the top 5 percent net load hours, i.e. those hours in which the remaining load is highest after subtracting out wind and solar generation. The WRAP also uses a five-hour duration for determining the capacity contribution of energy-limited resources, like batteries. A five-hour or longer duration storage resource receives a 100% contribution, while shorter durations are prorated relative to five hours, such that a one-hour storage has a 20% contribution, while four-hour storage has an 80% contribution. There is significant uncertainty about storage duration requirements and they are necessarily portfolio dependent, so the WRAP will update its capacity contribution calculations each year. PacifiCorp does not have the detailed information about WRAP participants to perform the same calculations over the IRP study horizon. Instead, Volume I, Chapter 6 (Load and Resource Balance) presents portfolio contributions to capacity for PacifiCorp's 2023 IRP with capacity allocated among resources primarily based on generation during the

		top 5 percent net load hours, which was also part of the WRAP design. Because ELCC analyses require very data intensive studies with long run times, they have not been performed for the 2023 IRP load and resource reporting across the 20-year IRP horizon. Instead, the remaining capacity between the net load peak and the coincident peak, including the planning reserve margin was allocated among those resources with generation during the top 5 percent load hours that exceeded that during the top 5 percent net load hours. In addition to the above, PacifiCorp used the five-hour duration assumption from the WRAP for energy-limited resources at the start of the IRP planning horizon, but increased the required duration as more energy storage resources were added to the preferred portfolio, which emulates the likely outcomes in the WRAP.
Order No. 22-178, p. 16	Commissioners, Staff, or the Administrative Hearings Division will lead … a workshop to discuss increasing efficiency and demand response, including the consideration of a new, or updated, risk-reduction credit to efficiency.	Not applicable. PacifiCorp is supportive of the workshop and plans to participate as more details are known.
Order No. 22-178, p. 16; Appx B p. 2	Staff stated that it is supportive of PacifiCorp's plan to include peak time rebates in the 2023 CPA. If peak time rebates are determined to be cost-effective, PacifiCorp should further include an exploration of the potential to use a third-party vendor to implement a peak time rebate in advance of the new billing system implementation, in comparison to an approach that waits until the new billing system is implemented, as part of its 2023 IRP.	Engaging a consultant and preparing a study for a peak time rebate that would use the Company pre-existing billing system would be premature and duplicative at this time, because the Company is actively in the process of replacing its billing system. While AMI is a necessary precedent before deploying a peak time rebate program, an advanced billing system is also needed with an analytical engine that is capable of accurately billing customers on peak time rebate. Fortunately, the new billing system the Company is planning to deploy would be able to process a peak time rebate program with some minor changes and would be in service on or around 2025. PacifiCorp did assess the potential costs and benefits of peak time rebates in the CPA to inform future determinations and considerations for implementation of peak time rebates.

Order No. 22-178, p. 16-17; Appx B p. 3	Require PacifiCorp to meet with developer intervenors, upon request, to determine a subset of the confidential data supporting the 2023 IRP that does not include commercially sensitive information that can be provided. The subset would not necessarily need to include all confidential data that is not commercially sensitive. Require PacifiCorp to seek to balance developer intervenors' need for information as IRP stakeholders with PacifiCorp's need to protect commercially sensitive information and keep the data management workload to a reasonable level.	PacifiCorp met twice with Commission Staff and associations that represent developers and developer stakeholders that participated in the Company's 2021 IRP proceeding, docket LC 77. The first meeting occurred on November 8, 2022 and a follow up meeting was held on March 20, 2023. As a result of these meetings, PacifiCorp restructured its workpaper reporting format that will allow a greater amount of information to be public. It will also designate commercially sensitive information as highly confidential; thus, ensuring developers will have access to all confidential information, not just a subset.
Order No. 22-178, p. 17	We direct PacifiCorp to hold at least one workshop on equity and justice issues related to the generation transition in its 2023 IRP, and we will ask members of our staff with expertise on these issues to participate. We recognize PacifiCorp's relationship to employees and to the communities where its resources are located and encourage the company to explain how consideration of both factor into planning processes.	PacifiCorp held a "Generation Transition Equity and Justice Workshop" on September 2, 2022. Topics included community action, promotion and organization of resources, employee transition plan and transition program, and current actions. The company has also held 14 CBIAG meetings since October 27, 2022.
Order No. 22-178, p. 18; Appx B p. 1	PacifiCorp to take steps to provide complete and accurate information in the 2023 IRP that reflects accurate IRP modeling assumptions. We adopt this recommendation, though we note that we believe PacifiCorp has already been attempting to comply with this principle.	PacifiCorp has aligned itself with this expectation by providing timely and comprehensive modeling outcomes, which have been included in the 2023 IRP and the preferred portfolio respectively.

Order No. 22-178, p. 18	Require PacifiCorp's 2023 IRP storage costs in the Supply Side Table to be in line with the most recent National Renewal Energy Laboratory Annual Technology Baseline report and most recent RFP Final Shortlist. Our understanding is that Staff's recommendation reflects a preference from stakeholders for publicly available sources, but that Staff also acknowledges the relevance of the market information obtainable from the most recent RFP. We thus adopt Staff's recommendation to the extent that it requires the use of publicly available data as well as proprietary sources, but with the understanding that discrepancies from the publicly available data be explained.	PacifiCorp presented on this topic at the September 1, Public Input Meeting.
Order No. 22-178, p. 18; Appx B p. 1	PacifiCorp to provide a map of resources in the IRP Executive Summary, which PacifiCorp agrees to do.	This requirement is met by the preferred portfolio map provided in Appendix I (Capacity Expansion Results).
Order No. 22-178, p. 18-19; Appx B p. 2	Require PacifiCorp to explain the reliability limitations of the LT capacity expansion model and how the IRP team selected the reliability resources of change. PacifiCorp made a strong effort at explanation in this IRP, but that the company should seek to understand questions that remain and mature its narrative discussion accordingly.	The LT model simultaneously evaluates the entire 20 year IRP horizon and all possible resource additions and retirements. With PacifiCorp's system and resource options, this is a lot of possibilities and the model cannot evaluate every hour, let alone maintain the chronological links necessary to consider all likely combinations of load, wind, and solar while enforcing energy storage duration limits, emissions constraints, and thermal unit cycling restrictions. As a result more granular analysis within the ST model is necessary to identify the extent that reliability, environmental compliance, and economics are addressed. Discussion of reliability resources follows below.

Order No. 22-178, p. 19; Appx B p. 2	Require PacifiCorp to include with the 2023 IRP data discs: A list of the resources that were considered as reliability resources; A list of the reliability resources that were selected in each portfolio, sensitivity, and variant; A clearly marked set of hourly reliability (ENS) data that the Company used to identify the type and size of reliability resources to add to each portfolio, sensitivity, variant; and Any metric the Company used to select reliability resources in each portfolio, sensitivity and variant	All resources were open to consideration as reliability resources for selection based on their value to the system. Workpapers will be provided for each case indicating portfolio changes and for each case indicating hourly unserved energy and reserve shortfalls. These workpapers identify the specific hours in which shortfalls occurred within each year. From the hourly shortfall data, the Company identified the largest consecutive blocks of shortfalls, including the month and hours of the day in which they occurred. The company then reviewed resource costs and benefits reported by Plexos specific to the case in question to determine which types of resources would be most economic to cover the identified need.
Order No. 22-178, p. 19; Appx B p. 2	Before the 2023 IRP, include climate-change risk and adaptation as a topic of a public-input meeting to share and discuss approaches to modeling climate risk in the IRP including: proposed changes to how weather and extreme events are considered; proposed changes for the consideration of climate-related risks on supply side resources, transmission, and loads; and a discussion on how the Company proposes to include climate change impacts as part of the status quo. We adopt this recommendation and note that we appreciate PacifiCorp's thorough responses on this important issue.	PacifiCorp engaged stakeholders on climate change at several public meetings, including: May 12, 2022 September 1-2, 2022 October 13, 2022 A primary function of these discussions was to discuss the incorporation of climate change as a base assumption in the 2023 IRP. In addition a "no climate change" study (W-11 Climate Change Counterfactual) is provided in the 2023 IRP.
Order No. 22-178, p. 20; Appx B p. 2	Change PacifiCorp's Environmental, Transmission, and DSM Updates from a twice-annual report to an annual report.	This change has been adopted.

Order No. 22-178, Appx B p. 1	In the 2023 IRP, PacifiCorp should provide a metric calculated in its capacity expansion model that provides stakeholders with an estimate of the relative value of each coal unit to the system.	This value is calculated in each study for every resource which is available for selection. Each resource's annual value is calculated, as well as an aggregate value over the period of the study.
Order No. 22-178,Appx B p. 1	The 2023 IRP data discs should provide graphs of the average fixed and variable costs of operating each coal unit over the planning timeframe. This should include fuel cost and run rate capital, but exclude depreciation expense.	PacifiCorp will provide appropriate reference materials on the data disc.
Order No. 22-178,Appx B p. 1	As a part of the 2023 IRP development process, PacifiCorp should fully assess the potential for gas conversion; use of hydrogen, biofuel, or other lower-carbon fuels; or alternate coal stockpile or supply methods for Jim Bridger 3 and 4. A report should be included with the 2023 IRP.	PacifiCorp presented its assessment of alternative fuels at the 2023 IRP June 9-10 public input meeting. *"LC 82 (PAC 2023 IRP) – Special Public Meeting – Waivers for extension to file the CEP and Long-Term Fuel Plan."*
Order No. 22-178,Appx B p. 1	If technically feasible, PacifiCorp should report on the costs and emissions (CO2 and NOX) of green hydrogen combustion at the converted Bridger unit.	PacifiCorp continues to assess the viability of green hydrogen, as well as the ability for existing infrastructure to accommodate the chemical properties of this fuel type. The Company's existing generation equipment is not well suited to green hydrogen combustion because exposure to high-temperature hydrogen results in degradation of many critical alloy components, particularly within steam turbines. Conversion of combustion turbines to hydrogen fueling is more promising, because the hot gas path is more contained, with fewer components at risk, but is not yet commercially available for the large turbines in PacifiCorp's fleet. Conversion of combustion turbines could potentially include combined cycle combustion turbines as the associated steam turbine is not directly exposed to hydrogen combustion.

Order No. 22-178,Appx B p. 1	The 2023 IRP should more thoroughly investigate the potential to install a new turbine designed to run on 100 percent green hydrogen at the sites of one or more retiring coal plants.	PacifiCorp continues to assess the viability of green hydrogen, as well as the ability for existing infrastructure to accommodate the chemical properties of this fuel type. PacifiCorp's modeling in the 2023 IRP allows for non-emitting peaking units at current coal plant sites and in other locations. These peaking resources were assumed to be fueled using 100 percent green hydrogen, supplied via pipeline due the high cost of onsite storage, but a wide variety of non-emitting fuels and generation technologies are currently under development.
Order No. 22-178,Appx B p. 1	In the 2023 IRP, variable O&M costs should be modeled accurately as variable with generation, and not approximated as part of fixed O&M costs as they have been in the 2021 IRP.	This enhancement has been incorporated for the 2023 IRP.
Order No. 22-178, Appx B p. 2	In future IRPs or during future RFP processes, potential RFP bidders should be given access to a 12x24 Loss of Load Probability matrix for one out of every five years in the IRP planning timeframe.	Following the completion of the 2021 IRP and in advance of bid submissions in the 2022 All-Source RFP, PacifiCorp prepared the requested information and provided it to stakeholders in its January 25, 2022 filing in docket UM 2011. Following the completion of the 2023 IRP, PacifiCorp will develop comparable information for use in future RFP processes.

Reference	IRP Requirement or Recommendation	How the Guideline is Addressed in the 2023 IRP
Utah		
DOCKET NO. 90-2035-01 p. 33-37	The forecasts will be made by jurisdiction and by general class and will differentiate energy and capacity requirements. The Company will include in its forecasts all on-system loads and those off-system loads which they have a contractual obligation to fulfill. Non-firm off-system sales are uncertain and should not be explicitly incorporated into the load forecast that the utility then plans to meet. However, the Plan must have some analysis of the off-system sales market to assess the impacts such markets will have on risks associated with different acquisition strategies.	PacifiCorp's load forecast is developed for each jurisdiction and by customer class. Further, this forecast includes off-system wholesale customers for which the Company has a contractual obligation to fulfill. To plan for non-firm off-system customer impacts returning to PacifiCorp's system, 1-year and 3-year option direct access customers in Oregon are incorporated into the forecast assuming they will return once their opt-out period expires.
DOCKET NO. 90-2035-01 p. 33-37	Analyses of how various economic and demographic factors, including the prices of electricity and alternative energy sources, will affect the consumption of electric energy services, and how changes in the number, type and efficiency of end-uses will affect future loads.	PacifiCorp has evaluated these market conditions to inform a least-cost, least-risk preferred portfolio outcome. Changes to consumer behavior are also outlined under the suite of existing demand-side management, energy efficiency and load forecast projections at the disposal of the Company.
DOCKET NO. 90-2035-01 p. 33-37	An evaluation of all present and future resources, including future market opportunities (both demand-side and supply-side), on a consistent and comparable basis.	PacifiCorp has attempted to include a wide range of potential resource options within its supply-side table, and has included reasonable cost estimates for all resource types. Where costs and operating characteristics are similar, as with different lithium-ion chemistries, the IRP does not attempt to differentiate – no particular technology is correct, and differences in performance are expected to be well within the normal range of offers from bidders. Even non-emitting peaking and nuclear resources are ultimately proxies for their particular combinations of costs, operating characteristics, and risks. Many types of risks are expected to evolve over the next few planning cycles both risks associated with these new technologies, and those associated with emitting technologies.

DOCKET NO. 90-2035-01 p. 33-37	An assessment of all technically feasible and cost-effective improvements in the efficient use of electricity, including load management and conservation.	PacifiCorp has evaluated all technically feasible and cost-effective energy efficiency, conservation, and load management through the Conservation Potential Assessment to compete with other resources in the IRP modeling.
DOCKET NO. 90-2035-01 p. 33-37	An assessment of all technically feasible generating technologies including: renewable resources, cogeneration, power purchases from other sources, and the construction of thermal resources.	PacifiCorp has evaluated all known technically feasible generating technologies including: renewable resources, cogeneration, and the construction of thermal resource. The IRP does not represent ownership structures for proxy resources. Any resource could end up being a Build Transfer Agreement (BTA), Power Purchase Agreement (PPA), self-build, or other contract structure.
DOCKET NO. 90-2035-01 p. 33-37	The resource assessments should include: life expectancy of the resources, the recognition of whether the resource is replacing/adding capacity or energy, dispatchability, lead-time requirements, flexibility, efficiency of the resource and opportunities for customer participation.	The resource assessments include: life expectancy of the resources, the recognition of whether the resource is replacing/adding capacity or energy, dispatchability, lead-time requirements, flexibility, and efficiency of the resource and opportunities for customer participation.
DOCKET NO. 90-2035-01 p. 33-37	An analysis of the role of competitive bidding for demand-side and supply-side resource acquisitions.	Demand side bids were permitted to participate in the all-source RFP and inputs for assessment was developed so that potential demand side bids could compete with supply side resources. Additionally, demand side resources are evaluated as part of the IRP modeling to evaluate overall competitiveness with other resources.

DOCKET NO. 90-2035-01 p. 33-37	A 20-year planning horizon.	The 2023 IRP covers a 20-year horizon from 2023 through 2042.
DOCKET NO. 90-2035-01 p. 33-37	A two-year action plan outlining the specific resource decisions intended to implement the integrated resource plan in a manner consistent with the Company's strategic business plan.	This requirement is met in Volume I, Chapter 10 (Action Plan).
DOCKET NO. 90-2035-01 p. 33-37	An action plan outlining the specific resource decisions intended to implement the integrated resource plan in a manner consistent with the Company's strategic business plan. The action plan will span a four-year horizon and will describe specific actions to be taken in the first two years and outline actions anticipated in the last two years. The action plan will include a status report of the specific actions contained in the previous action plan.	This requirement is met in Volume I, Chapter 10 (Action Plan).
DOCKET NO. 90-2035-01 p. 33-37	Load forecasts integrated with resource options in a manner which rationalizes the choice of resources under a variety of economic circumstances.	Modeling for the 2023 IRP incorporates multiple load forecasts and price-policy scenarios under which resources compete on an optimized basis for the selection of resource options, retirements, unit conversions, transmission options, market purchases and sales, and other elements. See Volume I, Chapters 7, 8 and 9.

DOCKET NO. 90-2035-01 p. 33-37	a plan of different resource acquisition paths for different economic circumstances with a decision mechanism to select among and modify these paths as the future unfolds.	PacifiCorp presents it alternative path analysis in Volume I, Chapter 10 (Action Plan).
DOCKET NO. 90-2035-01 p. 33-37	An evaluation of the cost-effectiveness of the resource options from a variety of perspectives and society as a whole.	PacifiCorp's 2023 IRP evaluates risk via a risk-adjustment metric based on stochastic modeling results, provides a set of competitive variant portfolios, and includes studies assuming a social cost of greenhouse gas cost-adder as a price-policy scenario.
DOCKET NO. 90-2035-01 p. 33-37	An evaluation of the risks associated with various resource options and how the action plan addresses these risks in the context of both the Business Plan and the 20-year Integrated Resource Plan.	PacifiCorp's 2023 IRP evaluates risk via a risk-adjustment metric based on stochastic modeling results, and includes a Business Plan sensitivity. The 2023 IRP will be used to inform the Business Plan.
DOCKET NO. 90-2035-01 p. 33-37	An evaluation of the financial, competitive, reliability, and operational risks associated with various resource options and how the action plan addresses these risks in the context of both the Business Plan and the 20-year Integrated Resource Plan. The Company will identify who should bear such risk, the ratepayer or the stockholder.	The 2023 IRP endogenously evaluates the attributes of competing resource options through its input data, which is reflective of the costs, operational characteristics, technology type, location, interconnection availability and other factors. In addition, the RFP non-price scoring process evaluates, in coordination with several independent evaluators representing three states, the project and reliability risks and scores these results accordingly. The assumptions in the Business Plan and 20-year Integrated Resource Plan are ultimately modified and realized through actual generating projects that are either owned or under contract and represent ratepayer risk, not shareholder risk, except to the extent that the commitments or actions of the Company are deemed imprudent in a future ratemaking proceeding. During RFP procurements, the terms of contracts are also reviewed by

		independent evaluators and are available and submitted to regulatory staff upon request or by order or statute. These contracts include performance guarantees to balance the risk between the project owner and the Company on behalf of ratepayers.
DOCKET NO. 90-2035-01 p. 33-37	Considerations permitting flexibility in the planning process so that the Company can take advantage of opportunities and can prevent the premature foreclosure of options.	PacifiCorp assesses the potential value of resources against risk and the expense of time and resources in the development of its supply side resources. The 2023 IRP included discussion of supply side resource, beginning earlier in the public input process than in previous IRPs, and revisited several times. Particular options were considered in expanded discussion topics such as coal options and offshore wind. The 2023 IRP also included natural gas resource options, which had been excluded in the 2021 IRP.
DOCKET NO. 90-2035-01 p. 33-37	An analysis of tradeoffs; for example, between such conditions of service as reliability and the acquisition of lowest cost resources.	The 2023 IRP inherently evaluates trade-offs between reliability and resource cost, as well as operational costs incurred during dispatch as part of the core functionality of optimization modeling. This is the purpose of the optimization. Additional analysis is provided in narrative form where salient trade-offs are indicated in portfolio outcomes. See Volume I, Chapter 9 (Modeling and Portfolio Selection Results).
DOCKET NO. 90-2035-01 p. 33-37	A range, rather than attempts at precise quantification, of estimated external costs which may be intangible, in order to show how explicit consideration of them might affect selection of resource options. The Company will attempt to quantify the magnitude of the externalities, for example, in terms of the amount of emissions released and dollar estimates of the costs of such externalities.	Future environmental and safety regulation has an almost unfathomable potential range of outcomes, many of which may be contradictory with other rules or policy goals, as in restrictions on non-emitting resources. What is certain, is that compliance may involve costs dramatically in excess of even the social cost of greenhouse gases price-policy scenario. As an example, coal ash handling and water treatment is only partly related to ongoing operations, but the costs could offset years of possible operational benefits depending on the circumstances. Environmental and safety regulation is not limited to fossil fuel resources, a few very basic examples include: - Very few battery chemistries have significant history in utility-scale operations, and some examples of fire hazards have been identified.

		- Wind turbines present risks related to birds and bats. - Cadmium telluride solar panels include two toxic chemicals, which while significantly less harmful in compound form, do not have well documented long-term effects. The above is not intended to be comprehensive - all technologies have trade-offs and risks though some technologies have more unknown unknowns than others. The largest externality of which the Company is currently aware is the impact of greenhouse gases on the climate. A price-policy scenario with an estimate of the social cost of greenhouse gases is used to quantify that particular externality, and analysis including those costs is presented for the preferred portfolio and selected variant portfolios.
DOCKET NO. 90-2035-01 p. 33-37	The public, state agencies and other interested parties will have the opportunity to make formal comment to the Commission on the adequacy of the Plan. The Commission will review the Plan for adherence to the principles stated herein, and will judge the merit and applicability of the public comment. If the Plan needs further work the Commission will return it to the Company with comments and suggestions for change. This process should lead more quickly to the Commission's acknowledgement of an acceptable Integrated Resource Plan. The Company will give an oral presentation of its report to the Commission and all interested public parties. Formal hearings on the acknowledgement of the Integrated Resource Plan might be appropriate but are not required. 7. Acknowledgement of an acceptable Plan will not guarantee favorable ratemaking treatment of future resource acquisitions.	PacifiCorp will participate fully in the described process.

Docket No. 21-035-09, UPSC June 2, 2022 Order p. 5-8	PacifiCorp must comply with Guidelines 4(b) and 4(i) by not constraining its model to preclude selection of new natural gas resources	The 2023 IRP included natural gas resource options, which had been excluded in the 2021 IRP.
Docket No. 21-035-09, UPSC June 2, 2022 Order p. 9-18	PacifiCorp will provide information to stakeholders three business days in advance of public meetings	PacifiCorp consistently provided meeting materials to stakeholders via email within the parameters of this requirement. See Volume II, Appendix C (Public Input).

DOCKET NO. 90-2035-01 p. 33-37	The Integrated Resource Plan will be used in rate cases to evaluate the performance of the utility and to review avoided cost calculations.	PacifiCorp is compliant with this standard.

Reference	IRP Requirement or Recommendation	How the Guideline is Addressed in the 2023 IRP
Washington		
State Rule/Statute Requirement	Incorporate the social cost of greenhouse gases (SCGHG) as a cost adder, as required by RCW 19.280.030(3), and provide a narrative illustrating step-by-step how the SCGHG cost adder is applied throughout its modeling logic. The SCGHG impact on the Company's modeling and portfolio analyses should be addressed in numerous variables, including PacifiCorp's imports and contracts and forward price curves.	PacifiCorp is compliant with this statute and has provided a narrative framework outlining carbon price policy scenario assumptions and nominal electric and natural gas price inputs, which were discussed at the February 23, 2023 Public Input meeting.
State Rule/Statute Requirement	Integrate the demand forecasts and resource evaluations into a long-range IRP solution describing the mix of resources that meet current and projected resource needs, abiding by a variety of constraints pursuant to statute and per Commission rule. WAC 480-100-620(11)	The Plexos models were used to evaluate resource on a comparable basis following the requirements in statute and appropriate to this filing's status as a Two-Year Progress Report. See Chapter 8 and Appendix O.
State Rule/Statute Requirement	Include an assessment of battery and pumped storage for integrating renewable resources. The assessment may consider ancillary services at the appropriate granularity required to model such storage resources. WAC 480-100-620(5)	The 2021 IRP Two-Year Progress Report incorporates multiple storage options including lithium-ion, flow and iron-air batteries, and pumped hydro storage. Modeling was conducted at appropriate granularity in the Plexos LT, MT and ST models. See Volume I, Chapters 7 and 8.
State Rule/Statute Requirement	A future climate change scenario that meets the requirements of WAC 480-100-620(10)(b), which is "At least one scenario must be a future climate change scenario. This scenario should incorporate the best science available to analyze impacts including, but not limited to, changes in snowpack, streamflow, rainfall, heating and cooling degree days, and load changes	PacifiCorp's base case includes future climate impacts on the load forecast, energy efficiency potential, and the hydro generation forecast. The base load forecast for the 2023 IRP is based on a Bureau of Reclamation median projection of climate impacts through time on heating and cooling degree days, resulting in increasing divergence from the 20-year normal weather further in the IRP planning horizon. The hydro forecast similarly relies on projected seasonal changes in streamflows in response to

	resulting from climate change."	climate impacts that evolve across the IRP planning horizon. A scenario using the 20-year normal weather forecast for load and hydro was prepared for comparison purposes.
State Rule/Statute Requirement	Identify an appropriate resource adequacy requirement (i.e., loss of load probability) and complete the assessment, as required by WAC 480-100-620(8)	This item is not required for a Two-Year Progress Report and is not explicitly addressed in terms of avoided cost in this filing. However, the Progress Report includes expanded reporting of reliability assessment including identifying deficiencies and the resolution of deficiencies based on model outcomes. The Plexos modeling process and the ENS metric indicates that reliability has been achieved.
State Rule/Statute Requirement	Provide resource assumptions and market forecasts used in the utility's schedule of estimated avoided costs required in WAC 480-106-040, including but not limited to: -Cost Assumptions -Production Estimates -Peak capacity contribution estimates and annual capacity factor estimates	This item is not required for a Two-Year Progress Report and is not explicitly addressed in terms of avoided cost in this filing. However, resource assumptions, capacity factors and price forecasts are included in workpapers. PacifiCorp would note that its 2023 IRP uses forward market prices from September 2022, which is the same vintage as PacifiCorp's November 1, 2022 avoided cost filing in docket number 220804
State Rule/Statute Requirement	Compare and evaluate all identified resources and potential changes to existing resources for achieving the clean energy transformation standards in WAC 480-100-610 at the lowest reasonable cost, including a narrative of the decisions it has made. WAC 480-100-620(7) and (11)	The 2021 IRP Two-Year Progress Report compares all resource options in its optimized evaluation, and provides narratives of comparative analysis of outcomes in Volume I, Chapter 9, and details regarding resource attributes in Volume I, Chapter 7.
	Address WAC 480-100-620(2), The IRP must include a range of forecasts of projected customer demand that reflect the effect of economic forces on the consumption of electricity and address changes in the number, type, and efficiency of end uses of electricity. 1.) alternative load forecast scenarios, including climate change impacts 2.) Optimistic and Pessimistic assumptions in the low and high growth models and how these alternative forecasts differ from the base forecast 3.) Electrification adjustments made to the load forecast	PacifiCorp conducts a variety of load forecast scenarios. Also, to account for changes in the number, type and efficiency of end-uses, the Company updates its statistically adjusted end-use model used in the load forecast. See Volume II, Appendix A (Load Forecast) for details regarding the alternative load forecast scenarios. Specifically, the Company's base forecast includes expected climate change impacts on loads, while the 20-year normal load forecast scenario provides the load forecast without explicitly accounting for climate change temperatures. Further, the Company does produce both optimistic and pessimistic load forecast scenarios. Please refer to Appendix A (Load Forecast) for details regarding transportation and building electrification adjustments made to the load forecast.
State Rule/Statute Requirement	Address how the IRP update meets with the requirement in RCW 19.280.030(1)(m) regarding electric and zero-emission vehicles. RCW 19.280.030(1)(m) An analysis	PacifiCorp's load forecast accounts for zero-emission vehicles using the methods to determine utility impacts described in the Company's Washington Transportation Electrification Plan. PacifiCorp develops multiple electric vehicle adoption futures

	of how the plan accounts for: (I) Modeled load forecast scenarios that consider the anticipated levels of zero emissions vehicle use in a utility's service area, including anticipated levels of zero emissions vehicle use in the utility's service area provided in RCW 47.01.520, if feasible; (ii) Analysis, research, findings, recommendations, actions, and any other relevant information found in the electrification of transportation plans submitted under RCW 35.92.450, 54.16.430, and 80.28.365; and (iii) Assumed use case forecasts and the associated energy impacts. Electric utilities may, but are not required to, use the forecasts generated by the mapping and forecasting tool created in RCW 47.01.520. This subsection (1)(m)(iii) applies only to plans due to be filed after September 1, 2023.	for consideration. PacifiCorp updated its zero-emission vehicle forecast in September of 2022 account for impacts from the inflation reduction act and recently adopted ZEV standards.
State Rule/Statute Requirement	Demonstrate a wider incorporation of non-energy impacts (NEIs) in addition to those applied during conservation potential assessment (CPA) development. WAC 480-100-620(11)(g)	PacifiCorp applied measure specific NEI results from a DNV NEI study in 2021 which developed a comprehensive assessment of NEIs. In response to stakeholder comments about NEI valuation, PacifiCorp revisited assumptions and presented results at the April 28, 2022, DSM advisory group meeting. Upon finalization of results, PacifiCorp mapped measure specific NEI's to measures in the conservation potential assessment. This represents a broader application of NEIs compared to the prior study which used a proxy value adder to represent NEI valuation. Additionally, for demand response, a literature review was conducted to determine if there were any program specific NEIs. Since no quantitative values were found in the literature review, PacifiCorp chose to include a 10% adder to approximate NEI impacts for demand response. In the prior study, no NEI's were included for demand response.
State Rule/Statute Requirement	Attribute NEIs considered, indicating whether nonenergy costs and benefits accrue to the utility, customers, participants, vulnerable populations, highly impacted communities, and/or the general public. WAC 480-100-620(13)	The file labeled "2023 CPA - Appendix E - WA Non-Energy Impact Mapping", as part of the CPA supplemental materials posted on the website, maps the accrual of NEIs to various groups consistent with WAC 480-100-620(13).
State Rule/Statute Requirement	Summarize (WAC 480-100-620(17)): -Public Comments received during the 2023 IRP development (rather than providing a download of stakeholder feedback forms the company has	PacifiCorp has maintained compliance with this requirement by publishing all stakeholder comments received and associated responses in a centralized location externally. The narrative framework for each stakeholder form received is also outlined in greater detail in Appendix C of the 2023 IRP.

	received to date -PacifiCorp corresponding responses to public comment -Whether and how the final plan addresses and incorporates comments received	
State Rule/Statute Requirement	Distributed energy resource (DER) potential assessments (WAC 480-100-620(3)(b)) Sub-section (iii) (energy assistance potential assessment)--The IRP must include distributed energy programs and mechanisms identified pursuant to RCW 19.405.120, which pertains to energy assistance and progress toward meeting energy assistance need. Sub-section (iv) (other DER potential assessments) – The IRP must assess other DERs that may be installed by the utility or the utility's customers including, but not limited to, energy storage, electric vehicles, and photovoltaics. Any such assessment must include the effect of DERs on the utility's load and operations. DER potential assessment(s) must go beyond the utility's legacy approach showing DERs as simply a load forecast decrement	The Company assesses various levels of DER through a variety of methods. PacifiCorp evaluates private generation by considering varying levels of technology costs and electricity rate assumptions, which are considered within the Company's high and low private generation load forecast sensitivities. With regard to the energy assistance potential assessment, PacifiCorp evaluates energy efficiency potential by income level so as to inform how energy efficiency resources can meet energy assistance need. The 2023 IRP also assesses other DERs such as energy storage, which is considered within the Company's private generation study and the CPA as a demand response resource for acquisition is subsequently incorporated into PacifiCorp's load forecast and IRP modeling. Further, utility scale battery storage is considered as a resource option within the context of portfolio analysis. The Company incorporates electric vehicle demand within the load forecast along with the control of electric vehicle load as a demand response resource in the IRP model.
State Rule/Statute Requirement	For the duration of the IRP public interest meetings (PIMs) informing PacifiCorp's 2023 IRP progress report cycle, circulate completed presentation materials at least three business days prior to each meeting. WAC 480-100-630(2).	PacifiCorp consistently provided meeting materials to stakeholders via email within the parameters of this requirement.
Order Requirement	Provide all data input files to the Commission in native format with appropriate context (e.g., assumptions made by the Company) as appendices or attachments to the final filing or via accompanying data disk(s). Dockets UE-191023 and UE-190698, General Order R-601 at 60-61, ¶ 173 and 178	PacifiCorp carefully manages its workpaper filing to adhere to this requirement within the limits of technology. Context is provided by the accompanying listing of file names with a description of the file's content or purpose. This information is provided on the data disk.
Order Requirement	Include complete data sets informing the Company's preferred portfolio. Dockets UE-191023 and UE-190698, General Order R-601 at 60-61, ¶ 173 and 178	The 2023 IRP data disc includes complete workpapers for each portfolio including the preferred portfolio.

Order Requirement	During CPA development, demonstrate progress towards identifying, researching, and properly valuing NEIs. Docket UE-210830, Order 01, Attachment A, condition 11a	PacifiCorp discussed NEI research with the DSM advisory group on October 12, 2021, February 28, 2022 and April 28, 2022 and with the equity advisory group on June 16, 2022. These discussions sought feedback on NEI valuation, research and application. The 2023 CPA included measure specific NEIs for energy efficiency and proxies for demand response that were more substantive and comprehensive compared to what was used in the 2021 CPA.
Rule Requirement	At least every two years after the utility files its IRP, beginning January 1, 2023, the utility must file a two-year progress report. (a) In this report, the utility must update its: (i) Load forecast; (ii) Demand-side resource assessment, including a new conservation potential assessment; (iii) Resource costs; and (iv) The portfolio analysis and preferred portfolio. (b) The progress report must include other updates that are necessary due to changing state or federal requirements, or significant changes to economic or market forces. (c) The progress report must also update for any elements found in the utility's current clean energy implementation plan, as described in WAC 480-100-640.	The 2023 IRP incorporates an updated load forecast, updated Demand-side management potential assessment, updated resource cost assumptions and portfolio analysis including the preferred portfolio. Please refer to Appendix O (Washington 2021 IRP Two-year Progress Report Additional Elements), for additional detail regarding updates for elements of the Clean Energy Implementation Plan.

Reference	IRP Requirement or Recommendation	How the Guideline is Addressed in the 2023 IRP
Wyoming		
The following requirements correspond to the WPSC's Order issued in the 2019 IRP investigation, the latest available for the 2023 IRP.		
Order, Docket No. 90000-144-XI-19 (Record No. 15280)	Include a Reference Case based on the 2017 IRP Updated Preferred Portfolio, incorporating updated assumptions, such as load and market prices and any known changes to system resources and using environmental investments or costs only required by current law. For example, the reference case will not include an estimate or	PacifiCorp has complied with this requirement. Additional information on the specified reference case can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation).

	assumed price or cost for carbon emissions absent an existing legal requirement.	
Order, Docket No. 90000-144-XI-19 (Record No. 15280)	Conduct a more extensive analysis of the impact of alternative price-policy scenarios on the resource plan.	The impact of price-policy scenarios on the resource plan is summarized in Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection).
Order, Docket No. 90000-144-XI-19 (Record No. 15280)	Conduct a sensitivity analysis on top performing portfolio cases and the reference case.	PacifiCorp has complied with this requirement. Additional information on sensitivity analyses can be found within Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection).
Order, Docket No. 90000-144-XI-19 (Record No. 15280)	Demonstrate rate impacts over the planning period between preferred portfolio and the reference case.	The 2023 IRP includes reference case P02-JB3-4 EOL, which continues Wyoming coal through end-of-life until necessity of gas conversion or other treatment driven by major by environmental requirements.
Order, Docket No. 90000-144-XI-19 (Record No. 15280)	Investigate alternative methodologies to integrate different reliability analyses including regional analysis of resource adequacy; analysis of power flow issues caused by retiring coal units; study of potential weather-related outages on intermittent generation; and an analysis of wildfire risk.	PacifiCorp has introduced a new chapter into this IRP – Volume I, Chapter 5 (Reliability and Resiliency) – which includes regional analyses of resource adequacy, a discussion of power flow issues caused by baseload resource retirements and how PacifiCorp Transmission is planning for those retirements, an assessment of weather-related outages, and a discussion of wildfire risk and mitigation.
Order, Docket No. 90000-144-XI-19 (Record No. 15280)	Include additional analysis on operational experience, if any, with battery acquisition and operations and include a review of capabilities learned from other utilities.	PacifiCorp has included a description of procurement and operational experience with battery acquisition and operations as part of Volume I, Chapter 7 (Resource Options).
Order, Docket No. 90000-144-XI-19 (Record No. 15280)	Include an analysis that demonstrates how the Company will maximize the use of dispatchable and reliable low-carbon electricity pursuant to HB200.	PacifiCorp has included Carbon Capture Utilization and Sequestration analysis within the portfolio modeling process. Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection Results).
Order, Docket No. 90000-144-XI-19 (Record No. 15280)	Incorporate an analysis of any agreed upon change to the MSP and to the extent there are outstanding material disagreements regarding cost allocation at the time of filing, quantify those risks and potential impact to Wyoming ratepayers.	PacifiCorp has included a discussion of the current status of the MSP within Volume I, Chapter 3 (Planning Environment). As there are no agreed-upon changes or outstanding material disagreements, PacifiCorp did not quantify potential impacts. To the extent that there are changes and/or material disagreements in future IRP cycles, the company will include the required quantified risk.
Order, Docket No. 90000-144-XI-19 (Record No. 15280)	Include a broader analysis of all generation types including nuclear and natural gas.	PacifiCorp has expanded the generation types included in the supply-side table as part of the 2023 IRP. Advanced nuclear and natural gas resources have both been included in the supply-side table and analyzed in the 2023 IRP. Additional newly

		evaluated resources include offshore wind and long-term storage options.
Order, Docket No. 90000-144-XI-19 (Record No. 15280)	Include a narrative discussing impacts and regulatory framework for renewable generation.	PacifiCorp has added this narrative analysis to the Planning Environment discussion in Volume I, Chapter 3 (Planning Environment).
Order, Docket No. 90000-144-XI-19 (Record No. 15280)	Include an acknowledgement that each of these requirements are addressed in the 2023 IRP to ensure compliance.	PacifiCorp acknowledges these requirements and has addressed each within the 2023 IRP.

Reference	IRP Requirement or Recommendation	How the Guideline is Addressed in the 2023 IRP
California		
D.18-02-018 D.22-02-004 Public Utilities Code §§ 399.13(a)(7), 454.5, 454.52	Addressing Disadvantaged Communities Provide supplemental information about disadvantaged communities, including "a demonstration of how disadvantaged communities were considered." (D.18-02-018, p. 135.) "PacifiCorp is required to supplement its multi-state IRP with … specific information on … a separate demonstration that satisfies the requirements for disadvantaged communities." (D.22-02-004, p. 22.) "At a minimum, all LSEs shall provide the following information in their IRPs: i. A description of which disadvantaged communities, if any, it serves (LSEs will be expected to make the determination of what is considered "disadvantaged" every two years); ii. What current and planned LSE activities/programs, if any, impact disadvantaged communities; and iii. A qualitative description of the demographics of the customers it serves and how it is currently addressing or plans to comply with the requirement to minimize air pollutants." (D.18-02-018, p. 68.)	PacifiCorp serves fewer than 50,000 customers in mostly rural northern California, with a significant number of customers on energy assistance programs. PacifiCorp's California customers are geographically-dispersed, with approximately four customers per square mile. [3]. PacifiCorp is committed to affordability to protect disadvantaged communities. In PacifiCorp's most current general rate case, which is currently pending at the California Public Utilities Commission, the company has requested recovery of costs associated with the addition of investments in renewable generation resources. Those resources reduce overall emissions and provide zero-fuel cost energy and production tax credits that benefit our customers. PacifiCorp also proposed an increase to its California Alternative Rates for Energy discount from 20 percent to 25 percent, new time varying rate options, and paperless bill credit, among other changes, to support customers during increased costs for wholesale energy and wildfire mitigation. In 2023, PacifiCorp plans to transition its Home Energy Savings residential energy efficiency program from a resource acquisition program to an equity program targeting Hard-to-Reach and Tribal csutomers. In addition, PacifiCorp filed an advice filing requesting approval to offer Home Energy Reports as an equity program targeting only Hard-to-Reach and Tribal customers.

[3] SB 535 Disadvantaged Communities | OEHHA (ca.gov)

	If we wish to provide additional information, we can address how PacifiCorp is: • strengthening "the diversity, sustainability, and resilience of the bulk transmission and distribution systems, and local communities." (D.18-02-018, p. 66; Pub. Util. Code § 454.52.) • minimizing "localized air pollutants and other greenhouse gas emissions, with early priority on disadvantaged communities." (D.18-02-018, p. 66; Pub. Util. Code § 454.52.) • giving "preference to renewable energy projects that provide environmental and economic benefits to communities afflicted with poverty or high unemployment, or that suffer from high emission levels of toxic air contaminants, criteria pollutants, and greenhouse gases." (D.18-02-018, p. 67; Pub. Util. Code § 399.13(a)(7).) In soliciting bids for new gas-fired generating units, PacifiCorp should "actively seek bids for resources that are not gas-fired generating units located in communities that suffer from cumulative pollution burdens, including, but no [sic] limited to, high emission levels of toxic air contaminants, criteria air pollutants, and greenhouse gases." (D.18-02-018, p. 67; Pub. Util. Code § 454.5(b)(9)(D).)	PacifiCorp IRP identifies increased investment in non-emitting resources to service all of its customers. Further, PacifiCorp does not own or operate any thermal generation in California that would negatively impact communities in the California service area.

D.19-04-040 D.22-02-004 ALJ Ruling Finalizing Load Forecasts and Greenhouse Gas Emissions Benchmarks for 2022 Integrated Resource Plan Filings	GHG Emissions Accounting "PacifiCorp should consult with Commission staff and describe an alternative [to the CNS/CSP Calculator] methodology that addresses its share of the 2030 GHG emissions reduction responsibility." (D.19-04-040, p. 74.) "PacifiCorp is required to supplement its multi-state IRP with … specific information on … another (non-CSP calculator) method to fulfill requirements that would otherwise have required the CSP tool and justification for the choice." (D.22-02-004, p. 22.) PacifiCorp's GHG benchmarks are available here: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2022-irp-cycle-events-and-materials/2022-final-ghg-emission-benchmarks-for-lses_public.xlsx	PacifiCorp met with CPUC staff in 2020 and discussed its alternative methodology to address GHG benchmarks. PacifiCorp's IRP supplement will include the results of the emissions forecast in California relative to GHG Benchmark.

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

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
Guideline 1. Substantive Requirements		
1.a.1	All resources must be evaluated on a consistent and comparable basis: All known resources for meeting the utility's load should be considered, including supply- side options which focus on the generation, purchase and transmission of power – or gas purchases, transportation, and storage – and demand-side options which focus on conservation and demand response.	PacifiCorp considered a wide range of resources including renewables, demand-side management, energy storage, power purchases, thermal resources, and transmission. Volume I, Chapter 4 (Transmission Planning), Chapter 7 (Resource Options), and Chapter 8 (Modeling and Portfolio Evaluation) document how PacifiCorp developed these resources and modeled them in its portfolio analysis. All these resources were established as resource options in the company's capacity expansion optimization model, Plexos, and selected by the model based on load requirements, relative economics, resource size, availability dates, and other factors.
1.a.2	All resources must be evaluated on a consistent and comparable basis: Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling.	All portfolios developed with Plexos were subjected to Monte Carlo production cost simulation. These portfolios contained a variety of resource types with different fuel types (coal, gas, biomass, nuclear fuel, "no fuel" renewables), lead-times (ranging from front office transactions to nuclear plants), in-service dates, operational lives, and locations. See Volume I, Chapter 8 (Modeling and Portfolio Evaluation), Chapter 9 (Modeling and Portfolio Selection Results), and Volume II, Appendix I (Capacity Expansion Results) and Appendix J (Stochastic Simulation Results).
1.a.3	All resources must be evaluated on a consistent and comparable basis: Consistent assumptions and methods should be used for evaluation of all resources.	PacifiCorp fully complies with this requirement. The company developed generic supply-side resource attributes based on a consistent characterization methodology. For demand-side resources, the company used the Applied Energy Group's supply curve data developed for this IRP for representation of DSM resources. The study was based on a consistently applied methodology for determining technical, market, and achievable DSM potentials. All portfolio resources were evaluated using the same sets of price and load forecast inputs. These inputs are documented in Volume I, Chapter 6 (Load and Resource Balance), Chapter 7 (Resource Options), and Chapter 8 (Modeling and Portfolio Evaluation) as well as Volume II, Appendix D (Demand-Side Management).
1.a.4	All resources must be evaluated on a consistent and comparable basis: The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs.	PacifiCorp applied its nominal after-tax WACC of 6.77 percent to discount all cost streams.

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
1.b.1	Risk and uncertainty must be considered: At a minimum, utilities should address the following sources of risk and uncertainty: 1. Electric utilities: load requirements, hydroelectric generation, plant forced outages, fuel prices, electricity prices, and costs to comply with any regulation of greenhouse gas emissions.	Each of the sources of risk identified in this guideline is treated as a stochastic variable in PacifiCorp's production cost simulation apart from CO2 emission compliance costs, which are treated as a scenario risk and evaluated as part of a CO2 price assumption and a no CO2, a high CO2, and a social cost of carbon price-policy scenario for specific studies. See Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Volume I, Chapter 9 (Modeling and Portfolio Selection Results).
1.b.2	Risk and uncertainty must be considered: Utilities should identify in their plans any additional sources of risk and uncertainty.	Resource risk mitigation is discussed in Volume I, Chapter 10 (Action Plan). Regulatory and financial risks associated with resource and transmission investments are highlighted in several areas in the IRP document, including Volume I, Chapter 3 (Planning Environment), Chapter 4 (Transmission), Chapter 8 (Modeling and Portfolio Evaluation), and Chapter 9 (Modeling and Portfolio Selection Results).
1.c	The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers ("best cost/risk portfolio").	PacifiCorp evaluated cost/risk tradeoffs for each of the portfolios considered. See Volume I, Chapter 9 (Modeling and Portfolio Selection Results), Chapter 10 (Action Plan), and Volume II, Appendix I (Capacity Expansion Results) and Appendix H (Stochastic Parameters) for the company's portfolio cost/risk analysis and determination of the preferred portfolio.
1.c.1	The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource.	PacifiCorp used a 20-year study period (2023-2042) for portfolio modeling, and a real levelized revenue requirement methodology for treatment of end effects.
1.c.2	Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all long-lived resources such as power plants, gas storage facilities, and pipelines, as well as all short- lived resources such as gas supply and short-term power purchases.	Volume I, Chapter 8 (Modeling and Portfolio Evaluation) provides a description of the PVRR methodology.

No.	Requirement	How the Guideline is Addressed in the 2021 IRP
1.c.3.1	To address risk, the plan should include, at a minimum: 1. Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes.	PacifiCorp uses the standard deviation of stochastic production costs as the measure of cost variability. For the severity of bad outcomes, the company calculates several measures, including stochastic upper-tail mean PVRR and the 95th percentile stochastic production cost PVRR.
1.c.3.2	To address risk, the plan should include, at a minimum: 2. Discussion of the proposed use and impact on costs and risks of physical and financial hedging.	A discussion on hedging is provided in Volume I, Chapter 10 (Action Plan).
1.c.4	The utility should explain in its plan how its resource choices appropriately balance cost and risk.	Volume I, Chapter 9 (Modeling and Portfolio Selection Results) summarizes the results of PacifiCorp's cost/risk tradeoff analysis and describes what criteria the company used to determine the best cost/risk portfolios and the preferred portfolio.
1.d	The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.	PacifiCorp considered both current and potential state and federal energy/pollutant emission policies in portfolio modeling. Volume I, Chapter 7 (Modeling and Portfolio Evaluation) describes the decision process used to derive portfolios, which includes consideration of state and federal resource policies and regulations that are summarized in Volume I, Chapter 3 (Planning Environment). Volume I, Chapter 9 (Modeling and Portfolio Selection Results) provides the results. Volume I, Chapter 10 (Action Plan) presents an acquisition path analysis that describes resource strategies based on regulatory trigger events.
Guideline 2. Procedural Requirements		
2.a	The public, which includes other utilities, should be allowed significant involvement in the preparation of the IRP. Involvement includes opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make relevant inquiries of the utility formulating the plan. Disputes about whether information requests are relevant or unreasonably burdensome, or whether a utility is being properly responsive, may be submitted to the Oregon PUC for resolution.	PacifiCorp fully complies with this requirement. Volume II, Appendix C (Public Input) provides an overview of the public input process, all public-input meetings held for the 2023 IRP, and summarizes public input received throughout the 2023 IRP cycle. PacifiCorp also made use of a Stakeholder Feedback Form for stakeholders to provide comments and offer suggestions. Stakeholder Feedback Forms along with responses and the public-input meeting presentations are available on PacifiCorp's webpage at: www.pacificorp.com/energy/integrated-resource- p lan.html
2.b	While confidential information must be protected, the utility should make public, in its plan, any non-confidential information that is relevant to its resource evaluation and action plan. Confidential information may be protected through use of a protective order, through aggregation or shielding of data, or through any other mechanism approved by the Oregon PUC.	2023 IRP Volumes I and II provide non-confidential information used for portfolio evaluation, as well as other data requested by stakeholders. PacifiCorp also provided stakeholders with non-confidential information to support public meeting discussions via email and in response to Stakeholder Feedback Forms. Data discs will be available with public data. Additionally, data discs with confidential data will be provided to appropriate parties through use of a general protective order.

2.c	The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Oregon PUC.	PacifiCorp distributed draft IRP materials for external review throughout the process prior to each of the public input meetings and solicited/and received feedback at various times when developing the 2023 IRP. The materials shared with stakeholders at these meetings, outlined in Volume II, Appendix C (Public Input), is consistent with materials presented in Volumes I and II of the 2023 IRP report. PacifiCorp requested and responded to comments from stakeholders when establishing modeling assumptions and throughout its portfolio-development process and sensitivity definitions.
Guideline 3: Plan Filing, Review, and Updates		
3.a	A utility must file an IRP within two years of its previous IRP acknowledgment order. If the utility does not intend to take any significant resource action for at least two years after its next IRP is due, the utility may request an extension of its filing date from the Oregon PUC.	The 2023 IRP complies with this requirement.
3.b	The utility must present the results of its filed plan to the Oregon PUC at a public meeting prior to the deadline for written public comment.	This activity will be conducted following the filing of this IRP.
3.c	Commission staff and parties should complete their comments and recommendations within six months of IRP filing.	This activity will be conducted following the filing of this IRP.
3.d	The Commission will consider comments and recommendations on a utility's plan at a public meeting before issuing an order on acknowledgment. The Commission may provide the utility an opportunity to revise the IRP before issuing an acknowledgment order.	This activity will be conducted following the filing of this IRP.

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
3.e	The Commission may provide direction to a utility regarding any additional analyses or actions that the utility should undertake in its next IRP.	Not applicable.
3.f	(a) Each energy utility must submit an annual update on its most recently acknowledged IRP. The update is due on or before the acknowledgment order anniversary date. Once a utility anticipates a significant deviation from its acknowledged IRP, it must file an update with the Oregon PUC, unless the utility is within six months of filing its next IRP. The utility must summarize the update at an Oregon PUC public meeting. The utility may request acknowledgment of changes in proposed actions identified in an update.	Not applicable to this filing; this activity will be conducted following the filing of this IRP.
3.g	Unless the utility requests acknowledgment of changes in proposed actions, the annual update is an informational filing that: • Describes what actions the utility has taken to implement the plan; • Provides an assessment of what has changed since the acknowledgment order that affects the action plan to select best portfolio of resources, including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource acquisitions, resource costs, and transmission availability; and • Justifies any deviations from the acknowledged action plan.	Not applicable to this filing; this activity will be conducted following the filing of this IRP.
Guideline 4. Plan Components: At a minimum, the plan must include the following elements		
No.	**Requirement**	**How the Guideline is Addressed in the 2023 IRP**
4.a	An explanation of how the utility met each of the substantive and procedural requirements.	The intent of this table is to comply with this guideline.
4.b	Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions.	PacifiCorp developed low, high, and extreme peak temperature (one-in-twenty probability) load growth forecasts for scenario analysis using the Plexos model. Stochastic variability of loads was also captured in the risk analysis. See Volume I, Chapters 6 (Load and Resource Balance) and Chapter 8 (Modeling and Portfolio Evaluation), and Volume II, Appendix A (Load Forecast Detail) for load forecast information.

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
4.c	For electric utilities, a determination of the levels of peaking capacity and energy capability expected for each year of the plan, given existing resources; identification of capacity and energy needed to bridge the gap between expected loads and resources; modeling of all existing transmission rights, as well as future transmission additions associated with the resource portfolios tested.	See Chapter 6 (Load and Resource Balance) for details on annual capacity and energy balances. Existing transmission rights are reflected in the IRP model topologies. Future transmission additions used in analyzing portfolios are summarized in Volume I, Chapter 4 (Transmission) and Chapter 8 (Modeling and Portfolio Evaluation).
4.d	For gas utilities only.	Not applicable.
4.e	Identification and estimated costs of all supply-side and demand side resource options, considering anticipated advances in technology.	Volume I, Chapter 7 (Resource Options) identifies the resources included in this IRP and provides their detailed cost and performance attributes. Additional information on energy efficiency resource characteristics is available in Volume II, Appendix D (Demand-Side Management Resources) referencing additional information on PacifiCorp's IRP website.
4.f	Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs.	In addition to incorporating a planning reserve margin for all portfolios evaluated, as supported by an updated Stochastic Loss of Load Study in Volume II, Appendix J (Stochastic Simulation Results), the company used several measures to evaluate relative portfolio supply reliability. These measures (Energy Not Served and Loss of Load Probability) are described in Volume I, Chapter 8 (Modeling and Portfolio Evaluation).
4.g	Identification of key assumptions about the future (e.g., fuel prices and environmental compliance costs) and alternative scenarios considered.	Volume I, Chapter 8 (Modeling and Portfolio Evaluation) describes the key assumptions and alternative scenarios used in this IRP. Volume II, Appendix I (Capacity Expansion Results) includes summaries of assumptions used for each case definition analyzed in the 2023 IRP.
4.h	Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations – system-wide or delivered to a specific portion of the system.	This IRP documents the development and results of portfolios designed to determine resource selection under a variety of input assumptions in Volume I, Chapters 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection Results).
4.i	Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties.	Volume I, Chapter 9 (Modeling and Portfolio Selection Results) incorporates the stochastic portfolio modeling results as described in Volume I, Chapter 8 (Modeling and Portfolio Evaluation), and describes portfolio attributes that explain relative differences in cost and risk performance.
4.j	Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results.	Volume I, Chapter 9 (Modeling and Portfolio Selection Results) provides tables and charts with performance measure results, including rank ordering.
4.k	Analysis of the uncertainties associated with each portfolio evaluated.	See responses to 1.b.1 and 1.b.2 above.

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
4.l	Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers.	See 1.c above.
4.m	Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation.	This IRP is designed to avoid inconsistencies with state and federal energy policies therefore none are currently identified.
4.n	An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing.	Volume I, Chapter 10 (Action Plan) presents the 2023 IRP action plan.

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
Guideline 5: Transmission		
5	Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving reliability.	PacifiCorp evaluated four sensitivities on Energy Gateway transmission project configurations on a consistent and comparable basis with respect to other resources. Where new resources would require additional transmission facilities the associated costs were factored into the analysis. Fuel transportation costs were factored into resource costs. In addition to endogenous resource and transmission selects, the 2023 IRP modeled seven variants' cases to evaluate Energy Gateway and its components, B2H, and Cluster 1 and 2 transmission. See Volume I, Chapter 8 (Modeling and Portfolio Evaluation), and specifically Table 8.11 – Preferred Portfolio Variants.
Guideline 6: Conservation		
6.a	Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.	PacifiCorp's conservation potential study is available on the company's webpage, and the most recent results from the conservation potential assessment have been incorporated into the IRP modeling process.
6.b	To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.	PacifiCorp's energy efficiency supply curves incorporate Oregon resource potential. Oregon potential estimates were provided by the Energy Trust of Oregon. See the demand-side resource section in Volume I, Chapter 7 (Resource Options), the results in Volume I, Chapter 9 (Modeling and Portfolio Selection Results), the targeted amounts in Volume I, Chapter 10 (Action Plan) and the implementation steps outlined in Volume II, Appendix D (DSM Resources
6.c	To the extent that an outside party administers conservation programs in a utility's service territory at a level of funding that is beyond the utility's control, the utility should: 1. Determine the amount of conservation resources in the best cost/risk portfolio without regard to any limits on funding of conservation programs; and 2. Identify the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition.	See the response for 6.b above.
Guideline 7: Demand Response		
7	Plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity, and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities).	PacifiCorp evaluated demand response resources (DSM) on a consistent basis with other resources.

Guideline 8: Environmental Costs		
No.	**Requirement**	**How the Guideline is Addressed in the 2023 IRP**
8.a	Base case and other compliance scenarios: The utility should construct a base-case scenario to reflect what it considers to be the most likely regulatory compliance future for carbon dioxide (CO_2), nitrogen oxides, sulfur oxides, and mercury emissions. The utility should develop several compliance scenarios ranging from the present CO_2 regulatory level to the upper reaches of credible proposals by governing entities. Each compliance scenario should include a time profile of CO_2 compliance requirements. The utility should identify whether the basis of those requirements, or "costs," would be CO_2 taxes, a ban on certain types of resources, or CO_2 caps (with or without flexibility mechanisms such as an allowance for credit trading as a safety valve). The analysis should recognize significant and important upstream emissions that would likely have a significant impact on resource decisions. Each compliance scenario should maintain logical consistency, to the extent practicable, between the CO_2 regulatory requirements and other key inputs.	See Volume I, Chapter 8 (Modeling and Portfolio Evaluation). In the 2023 IRP, PacifiCorp's base assumption includes a proxy price on CO_2 starting in 2025 within the medium gas/medium ("MM") CO_2 price-policy scenario for evaluation of all portfolios. In addition PacifiCorp modeled a high gas/high CO_2 ("HH") and a Social Cost of Greenhouse Gas price-policy scenario ("SC") for the preferred portfolio and relevant variants.
8.b	Testing alternative portfolios against the compliance scenarios: The utility should estimate, under each of the compliance scenarios, the present value revenue requirement (PVRR) costs and risk measures, over at least 20 years, for a set of reasonable alternative portfolios from which the preferred portfolio is selected. The utility should incorporate end-effect considerations in the analyses to allow for comparisons of portfolios containing resources with economic or physical lives that extend beyond the planning period. The utility should also modify projected lifetimes as necessary to be consistent with the compliance scenario under analysis. In addition, the utility should include, if material, sensitivity analyses on a range of reasonably possible regulatory futures for nitrogen oxides, sulfur oxides, and mercury to further inform the preferred portfolio selection.	Volume II, Appendix J (Stochastic Simulation Results) provides the stochastic mean PVRR versus upper tail mean less stochastic mean PVRR scatter plot diagrams that for a broad range of portfolios developed with a range of compliance scenarios as summarized in 8.a above. The company considers end-effects in its use of Real Levelized Revenue Requirement Analysis, as summarized in Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and uses a 20-year planning horizon. Early retirement and gas conversion alternatives to coal unit environmental investments were considered in the development of all resource portfolios.

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
8.c	Trigger point analysis: The utility should identify at least one CO_2 compliance "turning point" scenario, which, if anticipated now, would lead to, or "trigger" the selection of a portfolio of resources that is substantially different from the preferred portfolio. The utility should develop a substitute portfolio appropriate for this trigger-point scenario and compare the substitute portfolio's expected cost and risk performance to that of the preferred portfolio – under the base case and each of the above CO2 compliance scenarios. The utility should provide its assessment of whether a CO2 regulatory future that is equally or more stringent that the identified trigger point will be mandated.	See Volume I, Chapter 8 (Modeling and Portfolio Evaluation) for a description of initial portfolio development definitions. Comparative analysis of these case results is included in Volume I, Chapter 9 (Modeling and Portfolio Selection Results).
8.d	Oregon compliance portfolio: If none of the above portfolios is consistent with Oregon energy policies (including state goals for reducing greenhouse gas emissions) as those policies are applied to the utility, the utility should construct the best cost/risk portfolio that achieves that consistency, present its cost and risk parameters, and compare it to those in the preferred and alternative portfolios.	Several portfolios yield system emissions aligned with state goals for reducing greenhouse gas emissions. These cases are summarized in Volume I, Chapter 9 (Modeling and Portfolio Selection Results). PacifiCorp's Clean Energy Plan will filed by June 1, 2023, incremental to the statewide 2023 IRP preferred portfolio outcomes.

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
Guideline 9: Direct Access Loads		
9	An electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier.	Oregon Docket UE 267 established a long-term opt out option for eligible PacifiCorp customers. Going forward PacifiCorp will cease planning for customers who elect direct-access service on a long-term basis (i.e. five-year opt out customers).
Guideline 10: Multi-state Utilities		
10	Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated system basis that achieves a best cost/risk portfolio for all their retail customers.	The 2023 IRP conforms to the multi-state planning approach as stated in Volume I, Chapter 2 (Introduction) under the section "The Role of PacifiCorp's Integrated Resource Planning". The company notes the challenges in complying with multi-state integrated planning given differing state energy policies and resource preferences.
Guideline 11: Reliability		
11	Electric utilities should analyze reliability within the risk modeling of the actual portfolios being considered. Loss of load probability, expected planning reserve margin, and expected and worst-case unserved energy should be determined by year for top-performing portfolios. Natural gas utilities should analyze, on an integrated basis, gas supply, transportation, and storage, along with demand-side resources, to reliably meet peak, swing, and base-load system requirements. Electric and natural gas utility plans should demonstrate that the utility's chosen portfolio achieves its stated reliability, cost and risk objectives.	See the response to 1.c.3.1 above. Volume I, Chapter 9 (Modeling and Portfolio Selection Results) walks through the role of reliability, cost, and risk measures in determining the preferred portfolio. Scatter plots of portfolio cost versus risk at different CO_2 cost levels were used to inform the cost/risk tradeoff analysis.
Guideline 12: Distributed Generation		
12	Electric utilities should evaluate distributed generation technologies on par with other supply-side resources and should consider, and quantify where possible, the additional benefits of distributed generation.	PacifiCorp contracted with DNV to provide estimates of expected private generation penetration. The study was incorporated in the analysis as a deduction to load. Sensitivities looked at both high and low penetration rates for private generation. The study is included in Volume II, Appendix L (Private Generation Study).
Guideline 13: Resource Acquisition		

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
13.a	An electric utility should, in its IRP: 1. Identify its proposed acquisition strategy for each resource in its action plan. 2. Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party. 3. Identify any Benchmark Resources it plans to consider in competitive bidding.	Volume I, Chapter 10 (Action Plan) outlines the procurement approaches for resources identified in the preferred portfolio. A discussion of the advantages and disadvantages of owning a resource instead of purchasing it is included in Chapter 10 (Action Plan). PacifiCorp has not at this time identified any specific benchmark resources it plans to consider in the competitive bidding process summarized in the 2023 IRP action plan.
13.b	For gas utilities only.	Not Applicable
Flexible Capacity Resources		
1	Forecast the Demand for Flexible Capacity: The electric utilities shall forecast the balancing reserves needed at different time intervals (e.g. ramping needed within 5 minutes) to respond to variation in load and intermittent renewable generation over the 20- year planning period.	PacifiCorp as met this requirement in Volume II, Appendix F (Flexible Reserve Study).
2	Forecast the Supply of Flexible Capacity: The electric utilities shall forecast the balancing reserves available at different time intervals (e.g. ramping available within 5 minutes) from existing generating resources over the 20-year planning period.	PacifiCorp as met this requirement in Volume II, Appendix F (Flexible Reserve Study).
3	Evaluate Flexible Resources on a Consistent and Comparable Basis: In planning to fill any gap between the demand and supply of flexible capacity, the electric utilities shall evaluate all resource options, including the use of EVs, on a consistent and comparable basis.	PacifiCorp as met this requirement in Volume II, Appendix F (Flexible Reserve Study).

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

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
Procedural Issues		
1	The Commission has the legal authority to promulgate Standards and Guidelines for integrated resource planning.	Not addressed; this is a Public Service Commission of Utah responsibility.
2	Information Exchange is the most reasonable method for developing and implementing integrated resource planning in Utah.	Information exchange has been conducted throughout the 2023 IRP process.
3	Prudence reviews of new resource acquisitions will occur during ratemaking proceedings.	Not an IRP requirement as the Commission acknowledges that prudence reviews will occur during ratemaking proceedings, outside of the IRP process.
4	PacifiCorp's integrated resource planning process will be open to the public at all stages. The Commission, its staff, the Division, the Committee, appropriate Utah state agencies, and other interested parties can participate. The Commission will pursue a more active-directive role if deemed necessary, after formal review of the planning process.	PacifiCorp's public process is described in Volume I, Chapter 2 (Introduction). A description of public-input meetings is provided in Volume II, Appendix C (Public Input). Public-input meeting materials can also be found on PacifiCorp's website at: www.pacificorp.com/energy/integrated- resource-plan/public-input-process.html
5	Consideration of environmental externalities and attendant costs must be included in the integrated resource planning analysis.	PacifiCorp used a scenario analysis approach along with externality cost adders to model environmental externality costs. See Volume I, Chapter 8 (Modeling and Portfolio Evaluation) for a description of the methodology employed, including how CO_2 cost uncertainty is factored into the determination of relative portfolio performance through a base case planning assumption and other price-policy scenarios.
6	The integrated resource plan must evaluate supply-side and demand-side resources on a consistent and comparable basis.	Supply, transmission, and demand-side resources were evaluated on a comparable basis using Plexos optimization models. Also see the response to number 4.b.ii below.
7	Avoided cost should be determined in a manner consistent with the company's Integrated Resource Plan.	Consistent with Utah rules, PacifiCorp determination of avoided costs in Utah will be handled in a manner consistent with the IRP, with the caveat that the costs may be updated if better information becomes available.
8	The planning standards and guidelines must meet the needs of the Utah service area, but since coordination with other jurisdictions is important, must not ignore the rules governing the planning process already in place in other jurisdictions.	This IRP was developed in consultation with parties from all state jurisdictions and meets all formal state IRP guidelines.
9	The company's Strategic Business Plan must be directly related to its Integrated Resource Plan.	Volume I, Chapter 10 (Action Plan) describes the linkage between the 2023 IRP preferred portfolio and December 2022 business plan resources. Significant resource differences are highlighted. The business plan portfolio was run consistent with requirements outlined in the Order issued by the Utah Public Service Commission on September 16, 2016, Docket No. 15-035-04.

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
Standards and Guidelines		
1	Definition: Integrated resource planning is a utility planning process which evaluates all known resources on a consistent and comparable basis, to meet current and future customer electric energy services needs at the lowest total cost to the utility and its customers, and in a manner consistent with the long-run public interest. The process should result in the selection of the optimal set of resources given the expected combination of costs, risk and uncertainty.	Volume I, Chapter 8 (Modeling and Portfolio Evaluation) outlines the portfolio performance evaluation and preferred portfolio selection process, while Chapter 9 (Modeling and Portfolio Selection Results) chronicles the modeling and preferred portfolio selection process. This IRP also addresses concerns expressed by Utah stakeholders and the Utah commission concerning comprehensiveness of resources considered, consistency in applying input assumptions for portfolio modeling, and explanation of PacifiCorp's decision process for selecting top-performing portfolios and the preferred portfolio.
2	The company will submit its Integrated Resource Plan biennially.	The company submitted its last IRP on September 1, 2021, and filed this IRP on March 31, 2023, as an informational filing, meeting the requirement. PacifiCorp requested and was granted a 60 day extension of time to file the final 2023 IRP on May 31, 2023 in Docket No. 23-035-10.
3	IRP will be developed in consultation with the Commission, its staff, the Division of Public Utilities, the Committee of Consumer Services, appropriate Utah state agencies and interested parties. PacifiCorp will provide ample opportunity for public input and information exchange during the development of its Plan.	PacifiCorp's public process is described in Volume I, Chapter 2 (Introduction). A record of public meetings and a summary of feedback and public comments is provided in Volume II, Appendix C (Public Input).
4.a	PacifiCorp's integrated resource plans will include: a range of estimates or forecasts of load growth, including both capacity (kW) and energy (kWh) requirements.	PacifiCorp implemented a load forecast range for both capacity expansion optimization scenarios as well as for stochastic variability, covering both capacity and energy. Details concerning the load forecasts used in the 2021 IRP are provided in Volume I, Chapter 7 (Resource Options) and Volume II, Appendix A (Load Forecast).
4.a.i	The forecasts will be made by jurisdiction and by general class and will differentiate energy and capacity requirements. The company will include in its forecasts all on-system loads and those off- system loads which they have a contractual obligation to fulfill. Non-firm off-system sales are uncertain and should not be explicitly incorporated into the load forecast that the utility then plans to meet. However, the Plan must have some analysis of the off-system sales market to assess the impacts such markets will have on risks associated with different acquisition strategies.	Load forecasts are differentiated by jurisdiction and differentiate energy and capacity requirements. See Volume I, Chapter 6 (Load and Resource Balance) and Volume II, Appendix A (Load Forecast). Non-firm off-system sales are not incorporated into the load forecast. Off-system sales markets are included in IRP modeling and are used for system balancing purposes.
4.a.ii	Analyses of how various economic and demographic factors, including the prices of electricity and alternative energy sources, will affect the consumption of electric energy services, and how changes in the number, type and efficiency of end-uses will affect future loads.	Volume II, Appendix A (Load Forecast) documents how demographic and price factors are used in PacifiCorp's load forecasting methodology.

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
4.b	An evaluation of all present and future resources, including future market opportunities (both demand-side and supply-side), on a consistent and comparable basis.	Resources were evaluated on a consistent and comparable basis using the Plexos optimization models for both supply side and demand side alternatives. See explanation in Volume I, Chapter 7 (Modeling and Portfolio Evaluation) and the results in Volume I, Chapter 9 (Modeling and Portfolio Selection Results). Resource options are summarized in Volume I, Chapter 7 (Resource Options).
4.b.i	An assessment of all technically feasible and cost-effective improvements in the efficient use of electricity, including load management and conservation.	PacifiCorp included supply curves for Demand Response (dispatchable/schedulable load control) and Energy Efficiency in its capacity expansion model. Details are provided in Volume I, Chapter 7 (Resource Options).
4.b.ii	An assessment of all technically feasible generating technologies including renewable resources, cogeneration, power purchases from other sources, and the construction of thermal resources.	PacifiCorp considered a wide range of resources including renewables, cogeneration (combined heat and power), power purchases, thermal resources, energy storage, and Energy Gateway transmission configurations. Newly evaluated resources in this IRP include offshore wind and long-term storage options. Volume I, Chapters 7 (Resource Options) and 8 (Modeling and Portfolio Evaluation) contain assumptions and describe the process under which PacifiCorp developed and assessed these technologies and resources.
4.b.iii	The resource assessments should include: life expectancy of the resources, the recognition of whether the resource is replacing/adding capacity or energy, dispatchability, lead-time requirements, flexibility, efficiency of the resource and opportunities for customer participation.	PacifiCorp captures and models these resource attributes in its IRP models. Resources are defined as providing capacity, energy, or both. The DSM supply curves used for portfolio modeling explicitly incorporate estimated rates of program and event participation. The private generation study, modeled as a reduction to load, also considered rates of participation. Replacement capacity is considered in the case of early coal unit retirements as evaluated in this IRP as an alternative to coal unit environmental investments.
4.c	An analysis of the role of competitive bidding for demand-side and supply-side resource acquisitions	A description of the role of competitive bidding and other procurement methods is provided in Volume I, Chapter 10 (Action Plan).
4.d	A 20-year planning horizon.	This IRP uses a 20-year study horizon (2023-2042).
4.e	An action plan outlining the specific resource decisions intended to implement the integrated resource plan in a manner consistent with the company's strategic business plan. The action plan will span a four-year horizon and will describe specific actions to be taken in the first two years and outline actions anticipated in the last two years. The action plan will include a status report of the specific actions contained in the previous action plan.	The IRP action plan is provided in Volume I, Chapter 10 (Action Plan). A status report of the actions outlined in the previous action plan (2019 IRP Update) is provided in Volume I, Chapter 10 (Action Plan). In Volume I, Chapter 10 (Action Plan) Table 10.1 identifies actions anticipated in the next two-to-four years.

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
4.f	A plan of different resource acquisition paths for different economic circumstances with a decision mechanism to select among and modify these paths as the future unfolds.	Volume I, Chapter 10 (Action Plan) includes an acquisition path analysis that presents broad resource strategies based on regulatory trigger events, change in load growth, extension of federal renewable resource tax incentives and procurement delays.
4.g	An evaluation of the cost-effectiveness of the resource options from the perspectives of the utility and the different classes of ratepayers. In addition, a description of how social concerns might affect cost effectiveness estimates of resource options.	PacifiCorp provides resource-specific utility and total resource cost information in Volume I, Chapter 7 (Resource Options). The IRP document addresses the impact of social concerns on resource cost-effectiveness in the following ways: ● Relevant portfolios were evaluated using a range of CO_2 price-policy scenarios. ● A discussion of environmental policy status and impacts on utility resource planning is provided in Volume I, Chapter 3 (Planning Environment). ● State and proposed federal public policy preferences for clean energy are considered for development of the preferred portfolio, which is documented in Volume I, Chapter 9 (Modeling and Portfolio Selection Results). In addition, distinct state filings also address clean energy. ● Volume II, Appendix G (Plant Water Consumption) reports historical water consumption for PacifiCorp's thermal plants.

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
4.h	An evaluation of the financial, competitive, reliability, and operational risks associated with various resource options and how the action plan addresses these risks in the context of both the Business Plan and the 20-year Integrated Resource Plan. The company will identify who should bear such risk, the ratepayer, or the stockholder.	The handling of resource risks is discussed in Volume I, Chapter 10 (Action Plan), and covers managing environmental risk for existing plants, risk management and hedging and treatment of customer and investment risk. Transmission expansion risks are discussed in Volume I, Chapter 4 (Transmission). Resource capital cost uncertainty and technological risk is addressed in Volume I, Chapter 7 (Resource Options). For reliability risks, the stochastic simulation model incorporates stochastic volatility of forced outages for new thermal plants and hydro availability. These risks are factored into the comparative evaluation of portfolios and the selection of the preferred portfolio upon which the action plan is based. Identification of the classes of risk and how these risks are allocated to ratepayers and investors is discussed in Volume I, Chapter 10 (Action Plan).
4.i	Considerations permitting flexibility in the planning process so that the company can take advantage of opportunities and can prevent the premature foreclosure of options.	Flexibility in the planning and procurement processes is highlighted in Volume I, Chapter 10 (Action Plan).
4.j	An analysis of tradeoffs; for example, between such conditions of service as reliability and dispatchability and the acquisition of lowest cost resources.	PacifiCorp examined the trade-off between portfolio cost and risk, taking into consideration a broad range of resource alternatives defined with varying levels of dispatchability. This trade-off analysis is documented in Volume I, Chapter 9 (Modeling and Portfolio Selection Results).
4.k	A range, rather than attempts at precise quantification, of estimated external costs which may be intangible, to show how explicit consideration of them might affect selection of resource options. The company will attempt to quantify the magnitude of the externalities, for example, in terms of the number of emissions released and dollar estimates of the costs of such externalities.	PacifiCorp incorporated environmental externality costs for CO_2 and costs for complying with current and proposed U.S. EPA regulatory requirements. For CO_2 externality costs, the company used scenarios with various compliance requirements to capture a reasonable range of cost impacts. These modeling assumptions are described in Volume I, Chapter 8 (Modeling and Portfolio Evaluation).
4.l	A narrative describing how current rate design is consistent with the company's integrated resource planning goals and how changes in rate design might facilitate integrated resource planning objectives.	See Volume I, Chapter 3 (Planning Environment). The role of Class 3 DSM (price response programs) at PacifiCorp and how these resources are modeled in the IRP are described in Volume I, Chapter 7 (Resource Options).

5	PacifiCorp will submit its IRP for public comment, review and acknowledgment.	PacifiCorp distributed draft IRP materials for external review throughout the process prior to each of the public-input meetings and solicited/and received feedback at various times when developing the 2023 IRP. The materials shared with stakeholders at these meetings, outlined in Volume I, Chapter 2 (Introduction), is consistent with materials presented in Volumes I and II of the 2023 IRP report. Public-input meetings materials can be located on PacifiCorp's website at: www.pacificorp.com/energy/integrated-resource-plan/public-input-process.html PacifiCorp requested and responded to comments from stakeholders in throughout its 2023 IRP process. The company also considered comments received via Stakeholder Feedback Forms that can be located on PacifiCorp's website at: www.pacificorp.com/energy/integrated-resource-plan/comments.html A total of 133 Stakeholder Feedback Forms were received and responded to during the 2023 IRP public-input process.
6	The public, state agencies and other interested parties will have the opportunity to make formal comment to the Commission on the adequacy of the Plan. The Commission will review the Plan for adherence to the principles stated herein and will judge the merit and applicability of the public comment. If the Plan needs further work the Commission will return it to the company with comments and suggestions for change. This process should lead more quickly to the Commission's acknowledgment of an acceptable Integrated Resource Plan. The company will give an oral presentation of its report to the Commission, and all interested public parties. Formal hearings on the acknowledgment of the Integrated Resource Plan might be appropriate but are not required.	Not addressed; this is a post-filing activity.

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
7	Acknowledgment of an acceptable Plan will not guarantee favorable ratemaking treatment of future resource acquisitions.	Not addressed; this is not a PacifiCorp activity.
8	The Integrated Resource Plan will be used in rate cases to evaluate the performance of the utility and to review avoided cost calculations.	Not addressed; this refers to a post-filing activity.

Washington IRP requirements and the Washington IRP Two-Year Progress Report

Requirements for the Two-Year Progress Report are significantly reduced compared to the four-year filing of the full IRP. Requirements are focused primarily on fundamental data input updates necessary to update some interim and specific targets and report progress on other elements of the Clean Energy Implementation Plan. Nonetheless, PacifiCorp has attempted to adhere to all IRP filing requirements where possible in addition to the requirements of the Two-Year Progress Report, as detailed below.

Table B.5 – Washington Utilities and Transportation Commission IRP Standard and Guidelines to Implement CETA Rules (RCW 19.280.030 and WAC 480-100-620 through WAC 480-100-630) per Commission General Order R-601.

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
WAC 480-100-625(1) and (4)	Integrated resource plan updated every four years, with a progress report at least every two years.	The PacifiCorp IRP is published every two years with updates in the off cycles. This exceeds Washington State requirements. New to this IRP cycle is the requirement to file an IRP Two-Year Progress Report. This document constitutes the Progress Report.
WAC 480-100-620(1)	Unless otherwise stated, all assessments, evaluations, and forecasts comprising the plan should extend over the long-range (e.g., at least ten years; longer if appropriate to the life of the resources considered) planning horizon.	PacifiCorp's 2023 (and prior) IRPs span a 20-year long-term planning horizon. Additional analysis may extend beyond the 20-year horizon but not in the form of optimization modeling runs, as sufficient data is unavailable, resources insufficient and run times, which advance geometrically and not linearly with added years, are impractical. Rather than extrapolate all data inputs to cover longer periods, PacifiCorp extrapolates the optimized results.
WAC 480-100-620(2)	Plan includes range of forecasts of projected customer demand that reflect effect of economic forces on electricity consumption.	Variant load forecast cases will include High/low load, 1-in-20 load, High/low private generation, New Load and No Climate change load scenarios. Other load variants will be considered based on stakeholder feedback and model outcomes.
WAC 480-100-620(2)	Plan includes range of forecasts of projected customer demand that address changes in the number, type, and efficiency of electrical end-uses.	PacifiCorp has provided detail on load forecasts in Volume II, Appendix A (Load Forecast). Information can also be found in Volume I, Chapter 6 (Load and Resource Balance).
WAC 480-100-620(3)(a)	Plan includes load management assessments that are cost-effective and commercially available, including current and new policies and programs to obtain:	The IRP is informed by the company's current conservation potential assessment, which is available on PacifiCorp's website. Additional information on the load management assessments can be found in Volume II, Appendix D (Demand-Side Management Programs).

WAC 480-100-620(3)(a)	- all cost-effective conservation, efficiency, and load management improvements;	IRP modeling optimally selects all cost-effective energy efficiency and demand response in each case portfolio as a part of core model functionality. Results are reported for all portfolios in Volume I, Chapter 9 (Modeling and Portfolio Selection Results).
WAC 480-109-100(2)	- ten-year conservation potential used in the concurrent biennial conservation plan consistent with RCW 19.285.040(1);	The IRP is informed by the current conservation potential assessment, which is available on PacifiCorp's website. Volume I, Chapter 6 (Load and Resource Balance) provides additional detail.
	- identification of opportunities to develop combined heat and power as an energy and capacity resource; and	Combined heat and power are addressed as a component of the Private Generation Study, which is included in Volume II, Appendix L (Private Generation Study).
No.	**Requirement**	**How the Guideline is Addressed in the 2023 IRP**
WAC 480-100-620(3)(b)	- all demand response (DR) at the lowest reasonable cost (LRC).	IRP modeling optimally selects all cost-effective energy efficiency and demand response in each case portfolio as a part of core model functionality. Results are reported for all portfolios in Volume II, Chapter 9 (Modeling and Portfolio Selection Results).
WAC 480-100-620(3)(b)	Plan includes assessments of distributed energy programs and mechanisms pertaining to energy assistance and progress toward meeting energy assistance need, including but not limited to the following: - Energy efficiency and CPA, - Demand response potential, - Energy assistance potential	IRP modeling considers and selects energy efficiency and demand response potential, and distributed energy programs. Evaluation is detailed in Volume I, Chapter 8 (Modeling and Portfolio), and Chapter 9 (Modeling and Portfolio Selection Results).
WAC 480-100-620(3)(b)	Plan assesses a forecast of distributed energy resources (DER) that may be installed by the utility's customers via a planning process pursuant to RCW 19.280.100(2).	PacifiCorp has worked with DNV Consulting to prepare a Private Generation Study, which assesses distributed and customer-sited resources. Customer preference resources are also assessed as part of the portfolio selection process. Additional detail can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation).
WAC 480-100-620(3)(b)	Plan includes effect of DERs on the utility's load and operations.	The impacts of DERs on PacifiCorp's utility load and operations are assessed as part of Volume I, Chapter 8 (Modeling and Portfolio Evaluation). Inputs are assessed as part of Volume II, Appendix L (Private Generation Study).
WAC 480-100-620(3)(b)	If utility engages in a DER planning process, which is strongly encouraged, IRP should include a summary of the process planning results.	PacifiCorp understands this requirement and will include a summary in future integrated resource plans, if applicable. Also, summaries of our DER planning processes can be found in the conservation potential assessment and private generation studies posted on our website.

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
WAC 480-100-620(4)	Plan assesses wide range of conventional generating resources.	PacifiCorp considered a wide range of resources including renewables, demand-side management, energy storage, distributed energy resources, power purchases, thermal resources, and transmission. Volume I, Chapter 7 (Resource Options) provides relevant detail on conventional generating resources.
WAC 480-100-620(5)	In making new investments, plan considers acquisition of existing and new renewable resources at LRC.	Cost and performance data for all resource types is evaluated and entered as a model input for the optimal selection of resources. Additional information can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection).
See **WA-UTC energy storage policy statement** (UE-151069 & UE-161024 consolidated)	Plan assesses energy storage resources.	Energy storage resources are considered as part of the supply-side resource table, found in Volume I, Chapter 7 (Resource Options). Energy storage potential is assessed as part of Volume II, Appendix N (Energy Storage Potential Evaluation).
WAC 480-100-620(5)	Plan assesses nonconventional generating, integration, and ancillary service technologies.	Compressed air storage and advanced nuclear resources are represented in the Supply Resource Table, which is posted on PacifiCorp's IRP website and included as Volume I, Chapter 7 (Resource Options). All resource types are appropriately subject to integration and ancillary services determination, including transmission upgrade costs, reserve holding capability and additional reserve requirements that are particular to technologies. These factors are inherent to every portfolio optimization run.
WAC 480-100-620(6)	Plan assesses the availability of regional generation and transmission capacity for purposes of delivery of electricity to customers.	Regional generation is incorporated into market availability and price forecasts, which are described and analyzed in Volume I, Chapter 3 (Planning Environment), Chapter 5 (Reliability and Resiliency). Transmission and resource options are described in Volume I, Chapter 4 (transmission) and Chapter 7 (Resource Options).
WAC 480-100-620(6)	Plan assesses utility's regional transmission future needs and the extent	Regional transmission is represented through markets and region-based price forecasting, while PacifiCorp's transmission system is represented by firm

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
	transfer capability limitations may affect the future siting of resources.	transmission rights and endogenous transmission upgrade options. These factors are discussed in the Volume I, Chapter 7 (Resource Options) and Chapter 8 (Modeling and Portfolio Evaluation).
WAC 480-100-620(7)	Plan compares benefits and risks of purchasing power or building new resources.	As a component of core modeling functionality, all competing resources are evaluated to determine each optimal portfolio. Additional information can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection Results).
WAC 480-100-620(7)	Plan compares all identified resources according to resource costs, including:	The comparison of resources on a cost-risk basis is core functionality of PacifiCorp's optimization modeling. Additional information can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation).
WAC 480-100-620(7)	- transmission and distribution delivery costs;	PacifiCorp's transmission system is represented by firm transmission rights and endogenous transmission upgrade options. Transmission dependencies implying additional resource costs are included in the optimization, resulting in a reasonable comparison of resource costs. Additional information can be found in Volume I, Chapter 7 (Resource Options), Chapter 8 (Modeling and Portfolio Evaluation), and Chapter 9 (Modeling and Portfolio Selection Results).
WAC 480-100-620(7)	- risks, including environmental effects and the social cost of GHG emissions;	The Company has conducted six SC-GHG cases, three of which were evaluated under a range of additional price-policy conditions. The cases evaluated are described in Volume I, Chapter 8 (Modeling and Portfolio Evaluation).
WAC 480-100-620(7)	- benefits accruing to the utility, customers, and program participants (when applicable); and	Benefits are characterized by present value revenue requirement differentials, emissions, reserve and load deficiencies, robustness across stochastic variances and additional factors as may emerge from modeling results. In addition to modeling outcomes presented in Volume I, Chapter 8 (Modeling and Portfolio Evaluation), incremental costs relative to the Washington Clean Energy Implementation Plan are discussed in Volume II, Appendix O (Washington Two-Year Progress Report Additional Elements).
WAC 480-100-620(7)	- resource preference public policies adopted by WA State or the federal government.	The preferred portfolio selected in the 2023 IRP process is compliant with all policy requirements. A summary of the policy environment is included as Volume I, Chapter 3 (Planning Environment), and a description of the portfolio runs in compliance with policy is included as Volume I, Chapter 8 (Modeling and Portfolio Evaluation).

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
WAC 480-100-620(7)	Plan includes methods, commercially available technologies, or facilities for integrating renewable resources, including but not limited to battery storage and pumped storage, and addressing overgeneration events.	IRP modeling endogenously considers "overgeneration" in dispatch and curtails resources appropriately. These curtailments are an inherent component of the cost and risk valuation of each portfolio, and is a driver for the optimal size, type and location of selected resources.
WAC 480-100-620(8)	Plan assesses and determines resource adequacy metrics.	For the 2023 IRP, resource adequacy is evaluated as a core model function, where each portfolio is obligated to meet reliability requirements including varying degrees of quality of operating reserves. This is described in Volume I, Chapter 8 (Modeling and Portfolio Evaluation).
WAC 480-100-620(8)	Plan identifies an appropriate resource adequacy requirement.	PacifiCorp has addressed this requirement as described in Volume I, Chapter 6 (Load and Resource Balance).
WAC 480-100-620(8)	Plan measures corresponding resource adequacy metric consistent with prudent utility practice in eliminating coal-fired generation by 12/31/2025 (RCW 19.405.030), attaining GHG neutrality by 1/1/2030 (RCW 19.405.040), and achieving 100 percent clean electricity WA retail sales by 1/1/2045 (RCW 19.405.050).	PacifiCorp has addressed this requirement as pertains to requirements for the Clean Energy Transformation Act and the Two-Year Progress Report as described in Volume I, Chapter 6 (Load and Resource Balance), Chapter 8 (Modeling and Portfolio Evaluation), and Chapter 9 (Modeling and Portfolio Selection Results), and Volume II, Appendix O (Washington IRP Two-Year Progress Report Additional Elements).
WAC 480-100-620(9)	Plan reflects the cumulative impact analysis conducted under RCW 19.405.140, and includes an assessment of:	Please see Appendix O for details regarding the Company's plan for reporting on metrics related to CBIs.
WAC 480-100-620(9)	- energy and nonenergy benefits;	Please see Appendix O for details regarding the Company's plan for reporting on metrics related to CBIs.
WAC 480-100-620(9)	- reduction of burdens to vulnerable populations and highly impacted communities;	Please see Appendix O for details regarding the Company's plan for reporting on metrics related to CBIs.
WAC 480-100-620(9)	- long-term and short-term public health and environmental benefits, costs, and	Please see Appendix O for details regarding the Company's plan for reporting on metrics related to CBIs.

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
WAC 480-100-620(9)	- long-term and short-term public health and environmental risks; and	Please see Appendix O for details regarding the Company's plan for reporting on metrics related to CBIs.
WAC 480-100-620(9)	- energy security and risk.	Please see Appendix O for details regarding the Company's plan for reporting on metrics related to CBIs.
WAC 480-100-620(10)	Utility should include a range of possible future scenarios and input sensitivities for testing the robustness of the utility's resource portfolio under various parameters, including the following required components:	A wide range of cases and sensitivities under various price-policy futures have been included, as discussed in Volume I, Chapter 8 (Modeling and Portfolio Evaluation).
WAC 480-100-620(10)	*CETA counter factual scenario* - describe the alternative LRC and reasonably available portfolio that the utility would have implemented if not for the requirement to comply with RCW 19.405.040 and RCW 19.405.050, as described in WAC 480-100-660(1).	PacifiCorp has met this requirement – additional detail can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation).
WAC 480-100-620(10)	*Climate change scenario* - incorporate the best science available to analyze impacts including, but not limited to, changes in snowpack, streamflow, rainfall, heating and cooling degree days, and load changes resulting from climate change.	PacifiCorp has met this requirement – additional detail can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation).
WAC 480-100-620(10)	*Maximum customer benefit sensitivity* - model the maximum amount of customer benefits described in RCW 19.405.040(8) prior to balancing against other goals.	PacifiCorp has met this requirement – additional detail can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation).
WAC 480-100-620(11)	Plan must integrate demand forecasts and resource evaluations into a long-range IRP solution.	PacifiCorp has met this requirement – additional detail can be found in Volume I, Chapter 6 (Load and Resource Balance).
WAC 480-100-620(11)	IRP solution or preferred portfolio must describe the resource mix that meets current and projected needs.	PacifiCorp has met this requirement – additional detail can be found in Volume I, Chapter 9 (Modeling and Portfolio Selection).

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
WAC 480-100-620(11)(a)	Preferred portfolio must include narrative explanation of the decisions made, including how the utility's long-range IRP solution:	See individual entries below.
WAC 480-100-620(11)(a)	- achieves requirements for eliminating coal-fired generation by 12/31/2025 (RCW 19.405.030);	PacifiCorp will remove coal-fired generation from Washington's allocation of electricity by 2025 and will continue to analyze this pending further resolution of interpretive issues by the Commission. Additional information can be found in Volume I, Chapter 9 (Modeling and Portfolio Selection Results).
WAC 480-100-620(11)(a)	- attains GHG neutrality by 1/1/2030 (RCW 19.405.040); and	PacifiCorp has met this requirement. Additional information can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection Results), and Volume II Appendix O (Washington IRP Two-Year Progress Report Additional Elements).
WAC 480-100-620(11)(a)	- achieves 100 percent clean electricity WA retail sales by 1/1/2045 (RCW 19.405.050) at LRC,	This is outside of the Two-Year Progress Report timeline, but is addressed as part of Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection Results), and Volume II, Appendix O (Washington IRP Two-Year Progress Report Additional Elements).
WAC 480-100-620(11)(a)	- achieves 100 percent clean electricity WA retail sales by 1/1/2045 (RCW 19.405.050), considering risk.	This is outside of the Two-Year Progress Report timeline, but the pathway to 2045 is addressed in Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection Results), and Volume II, Appendix O (Washington IRP Two-Year Progress Report Additional Elements).
WAC 480-100-620(11)(c)	Consistent with RCW 19.285.040(1), preferred portfolio shows pursuit of all cost-effective, reliable, and feasible conservation and efficiency resources, and DR.	PacifiCorp has met this requirement. Additional information can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation), Chapter 9 (Modeling and Portfolio Selection Results), and Volume II, Appendix O (Washington IRP Two-Year Progress Report Additional Elements).
WAC 480-100-620(11)(d) and I	Preferred portfolio considers acquisition of existing renewable new resources and relies on renewable resources and energy storage, insofar as doing so is at LRC,	PacifiCorp has met this requirement. Additional information can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation), Chapter 9 (Modeling and Portfolio Selection Results), and Volume II, Appendix O (Washington IRP Two-Year Progress Report Additional Elements).
WAC 480-100-620(11)(d) and (e)	Preferred portfolio considers acquisition of existing renewable new resources and relies on renewable resources and energy storage, considering risks.	PacifiCorp has met this requirement. Additional information can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation), Chapter 9 (Modeling and Portfolio Selection Results), and Volume II, Appendix O (Washington IRP Two-Year Progress Report Additional Elements).
WAC 480-100-620(11)(f)	Preferred portfolio maintains and protects the safety, reliable operation, and balancing of the utility's electric system, including mitigating over-generation events and achieving identified resource adequacy requirements.	PacifiCorp has met this requirement. Additional information can be found in Volume I, Chapter 6 (Load and Resource Balance).

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
WAC 480-100-620(11)(g)	Preferred portfolio ensures all customers are benefiting from the transition to clean energy through the:	
WAC 480-100-620(11)(g)	- equitable distribution of energy and nonenergy benefits; reduction of burdens to vulnerable populations and highly impacted communities;	Please see Volume II Appendix O (Washington IRP Two-Year Progress Report Additional Elements).
WAC 480-100-620(11)(g)	- long-term and short-term public health and environmental benefits; reduction of costs and risks; and	Please see Volume II Appendix O (Washington IRP Two-Year Progress Report Additional Elements).
WAC 480-100-620(11)(g)	- energy security and resiliency.	Please see Volume II Appendix O (Washington IRP Two-Year Progress Report Additional Elements).
WAC 480-100-620(11)(h)	Preferred portfolio: assesses the environmental health impacts to highly impacted communities,	Please see Volume II Appendix O (Washington IRP Two-Year Progress Report Additional Elements).
WAC 480-100-620(11)(i)	- analyzes and considers combinations of DER costs, benefits, and operational characteristics (incl. ancillary services) to meet system needs,	Detail is included in Volume I, Chapter 8 (Modeling and Portfolio Evaluation).
WAC 480-100-620(11)(j)	- incorporates the social cost of GHG emissions as a cost adder.	Detail is included in Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Volume II, Appendix O (Washington IRP Two-Year Progress Report Additional Elements).
WAC 480-100-620(12)	Utility must develop a ten-year **clean energy action plan** (CEAP) for implementing RCW 19.405.030 through 19.405.050 at LRC, and at an acceptable resource adequacy standard. The CEAP will:	The Company's CEAP was provided in the 2021 Integrated Resource Plan published September 1, 2021.
WAC 480-100-620(12)(b)	- identify and be informed by utility's ten-year CPA per RCW 19.285.040(1);	The Clean Energy Action Plan is not a component of the IRP Two-Year Progress Report.
WAC 480-100-620(12)(c)	- demonstrate that all customers are benefiting from the transition to clean energy;	The Clean Energy Action Plan is not a component of the IRP Two-Year Progress Report.
WAC 480-100-620(12)(d)	- establish a resource adequacy requirement;	PacifiCorp establishes resource adequacy at a system level, and the resource adequacy requirement is explained in Volume I, Chapter 6 (Load and Resource Balance).
WAC 480-100-620(12)(e)	- identify the potential cost-effective DR and load management programs that may be acquired;	This requirement is met in Volume I, Chapter 9 (Modeling and Portfolio Selection Results) and Volume II, Appendix O (Washington IRP Two-Year Progress Report Additional Elements).
WAC 480-100-620(12)(f)	- identify renewable resources, non emitting electric generation, and DERs that may be acquired and evaluate how each identified resource may be expected to contribute to meeting the utility's resource adequacy requirement;	This is described at the system-level as part of PacifiCorp's resource planning process. Volume I, Chapter 7 (Resource Options), Chapter 8 (Modeling and Portfolio Evaluation), and Chapter 9 (Modeling and Portfolio Selection) provide additional detail.

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
WAC 480-100-620(12)(g)	- identify any need to develop new, or expand or upgrade existing, bulk transmission and distribution facilities; and	This is described at the system level in Volume I, Chapter 4 (Transmission) and also within PacifiCorp's Volume I, Chapter 10 (Action Plan).
WAC 480-100-620(12)(h)	- identify the nature and possible extent to which the utility may need to rely on alternative compliance options, if appropriate.	Please see Volume II Appendix O (Washington IRP Two-Year Progress Report Additional Elements).
WAC 480-100-620(12)(i)	Plan (both IRP and CEAP) considers cost of greenhouse gas emissions as a **cost adder** equal to the cost per metric ton of carbon dioxide emissions, using the two and one-half percent discount rate, listed in Table 2, Technical Support Document: Technical update of the social cost of carbon (SCC) for regulatory impact analysis under Executive Order 12866, published by the interagency working group on social cost of greenhouse gases of the United States government, August 2016, as adjusted by the Commission to reflect the effect of inflation.	PacifiCorp updated its social cost of greenhouse gas pricing consistent with DOCKET U-190730 ORDER 03, which updates this specification.
WAC 480-100-620(13)	Plan must include an analysis and summary of the estimated avoided cost for each supply- and demand-side resource, including (but not limited to):	A new assessment of avoided cost is not a requirement of the Two-Year Progress Report; however, future determinations of avoided cost will follow the guidelines below.
WAC 480-100-620(13)	- energy,	The estimated avoided cost will be based on the values determined through the IRP modeling process. Values can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection).
WAC 480-100-620(13)	- capacity,	The estimated avoided cost will be based on the values determined through the IRP modeling process. Values can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection).
WAC 480-100-620(13)	- transmission,	The estimated avoided cost will be based on the values determined through the IRP modeling process. Values can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection).
WAC 480-100-620(13)	- distribution, and	The estimated avoided cost will be based on the values determined through the IRP modeling process. Values can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection).
WAC 480-100-620(13)	- GHG emissions.	The estimated avoided cost will be based on the values determined through the IRP modeling process. Values can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection).

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
WAC 480-100-620(13)	Listed energy and non-energy impacts should specify to which source party they accrue (e.g., utility, customers, participants, vulnerable populations, highly impacted communities, general public).	The file labeled "2023 CPA - Appendix E - WA Non-Energy Impact Mapping", as part of the CPA supplemental materials posted on the website, maps the accrual of NEIs to various groups consistent with WAC 480-100-620(13).

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
WAC 480-106-040	Plan provides information and analysis used to inform annual purchases of electricity from qualifying facilities, including a description of the:	A new assessment of avoided cost is not a requirement of the Two-Year Progress Report; however, future determinations of avoided cost will follow the guidelines below.
WAC 480-106-040	- avoided cost calculation methodology used;	The estimated avoided cost will be based on the values determined through the IRP modeling process. Values can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection).
WAC 480-106-040	- avoided cost methodology of energy, capacity, transmission, distribution, and emissions averaged across the utility; and	The estimated avoided cost will be based on the values determined through the IRP modeling process. Values can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection).
WAC 480-106-040	- resource assumptions and market forecasts used in the utility's schedule of estimated avoided cost, including (but not limited to): cost assumptions, production estimates, peak capacity contribution estimates, and annual capacity factor estimates.	The estimated avoided cost will be based on the values determined through the IRP modeling process. Values can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection).
WAC 480-100-620(14)	To maximize transparency, the utility should submit data input files supporting the plan in native file format (e.g., supporting spreadsheets in Excel, not PDF file format).	PacifiCorp will make data available in the native file format consistent with practice in prior IRPs.
WAC 480-100-620(15)	Information relating to purchases of electricity from qualifying facilities. Each utility must provide information and analysis that it will use to inform its annual filings required under chapter 480-106 WAC. The detailed analysis must include, but is not limited to, the following components:	
WAC 480-100-620(15)(a)	A description of the methodology used to calculate estimates of the avoided cost of energy, capacity, transmission, distribution and emissions averaged across the utility; and	The estimated avoided cost will be based on the values determined through the IRP modeling process. Values can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection).
WAC 480-100-620(15)(b)	(b) Resource assumptions and market forecasts used in the utility's schedule of estimated avoided cost required in WAC 480-106-040 including, but not limited to, cost assumptions, production estimates, peak capacity contribution estimates and annual capacity factor estimates.	The estimated avoided cost will be based on the values determined through the IRP modeling process. Values can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection).
WAC 480-100-620(16)	Plan must summarize substantive changes to modeling methodologies or inputs that change the utility's resource need, as compared to the utility's previous IRP.	An assessment of modeling methodology is included in Volume I, Chapter 8 (Modeling and Portfolio Evaluation).
WAC 480-100-620(17)	Utility must summarize:	
WAC 480-100-620(17)	- public comments received on the draft IRP,	This is included in Volume II, Appendix C (Public Input).

WAC 480-100-620(17)	- utility's responses to public comments, and	This is included in Volume II, Appendix C (Public Input).
WAC 480-100-620(17)	- whether final plan addresses and incorporates comments raised.	This is included in Volume II, Appendix C (Public Input).

Table B.6 – Wyoming Public Service Commission Guidelines

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
A	The public comment process employed as part of the formulation of the utility's IRP, including a description, timing and weight given to the public process;	PacifiCorp's public process is described in Volume I, Chapter 2 (Introduction) and in Volume II, Appendix C (Public Input).
B	The utility's strategic goals and resource planning goals and preferred resource portfolio;	Volume I, Chapter 9 (Modeling and Portfolio Selection Results) documents the preferred resource portfolio and rationale for selection. Volume I, Chapter 10 (Action Plan) constitutes the IRP action plan and the descriptions of resource strategies and risk management.
C	The utility's illustration of resource need over the near-term and long-term planning horizons;	See Volume I, Chapter 6 (Load and Resource Balance).
D	A study detailing the types of resources considered;	Volume, I Chapter 7 (Resource Options), presents the resource options used for resource portfolio modeling for this IRP.
E	Changes in expected resource acquisitions and load growth from that presented in the utility's previous IRP;	A comparison of resource changes relative to the 2021 IRP is presented in Volume I, Chapter 10 (Action Plan). A chart comparing the peak load forecasts for the 2019 IRP, and 2021 IRP is included in Volume II, Appendix A (Load Forecast Details).
F	The environmental impacts considered;	Portfolio comparisons for CO2 and a broad range of environmental impacts are considered, including prospective early retirement and gas conversions of existing coal units as alternatives to environmental investments. See Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection) as well as Volume II, Appendix J (Stochastic Simulation Results).
G	Market purchases evaluation;	Modeling of firm market purchases (front office transactions) and spot market balancing transactions is included in the 2021 IRP.
H	Reserve Margin analysis; and	Reserve margin analysis is included in Volume I, Chapter 8 (Modeling and Portfolio Evaluation).
I	Demand-side management and conservation options;	See Volume I, Chapter 7 (Resource Options) and Volume II, Appendix D (Demand-side Management) for a detailed discussion on DSM and energy efficiency resource options. Additional information on energy efficiency resource characteristics is available on the company's website.

APPENDIX C – PUBLIC INPUT PROCESS

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

Stakeholders have been involved in the development of the 2023 IRP from the beginning. The public-input meetings held beginning in January 2022 were the cornerstone of the direct public-input process, and there have been 10 public-input meetings held as part of the 2023 IRP development cycle. Due to restrictions and concerns surrounding COVID-19, all meetings have been held via phone conference, with no in-person participation.

The IRP public-input process also included state-specific stakeholder dialogue sessions held in the summer of 2022. The goal of these sessions was to capture key IRP issues of most concern to each state, as well as to discuss how to tackle these issues from a system planning perspective. PacifiCorp wanted to ensure stakeholders understood IRP planning principles. These meetings continued to enhance interaction with stakeholders in the planning cycle and provided a forum to directly address stakeholder concerns regarding equitable representation of state interests during public- input meetings.

PacifiCorp solicited agenda item recommendations from stakeholders in advance of the state meetings. There was additional open time to ensure participants had adequate opportunity for dialogue.

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 2023 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

Stakeholders and Industry Experts

- ESS, INC
- Renewable Northwest
- SLC Corp
- Utah Division of Public Utilities
- Western Resource Advocates
- Holland & Hart
- Sierra Club
- Utah Clean Energy
- Interwest Energy Alliance
- Powder River Basin Resource Council
- Northwest Energy Coalition
- Fervo Energy
- Washington Utilities and Transportation Commission
- Renewable Energy Coalition
- Western Energy Storage Task Force
- Enyo
- Apex
- City of Kemmerer Wyoming
- NW Power Council
- Energy Trust of Oregon
- Oregon League of Women Voters
- Oregon Citizen Utility Board
- University of Wyoming
- Applied Energy Group
- Intermountain Wind-Colorado
- Meta
- City of SLC
- Wyoming Energy Consumers
- Wyoming Office of Consumer Advocates
- Powder River Basin Conservation League
- Wyoming Coalition of Local Governments

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

As mentioned above, PacifiCorp has hosted 10 public-input meetings, as well as five state meetings during the public-input process, with an additional public-input meeting scheduled for April 2023. During the 2023 IRP public-input process presentations and discussions have covered various issues regarding inputs, assumptions, risks, modeling techniques, and analytical results. Below are the agendas from the public-input meetings; the presentations can be located at:

[ttps://www.pacificorp.com/energy/integrated-resource-plan/public-input-process.html](https://www.pacificorp.com/energy/integrated-resource-plan/public-input-process.html)

For the 2023 IRP, all General Public Meeting were held via conference call. The company has initiated making recording of these meeting publicly available through the IRP website:

General Meetings

February 25, 2022 – General Public Meeting (meeting materials provided to stakeholders on February 21, 2022)

- Conservation Potential Assessment (CPA)
- 2023 Supply-Side Resources
- 2021 IRP Update / 2023 IRP Overview
- 2023 IRP Public-Input Meeting Schedule

April 7, 2022 – General Public Meeting (meeting materials provided to stakeholders on April 4, 2022)

- Introductions
- 2023 Conservation Potential Assessment (CPA)
- Planning Environment Update
- Optimization Modeling Overview

May 12, 2022 – General Public Meeting (meeting materials provided to stakeholders on May 8, 2022)

- Conservation Potential Assessment
- Request For Proposals Update
- Price Curve Development Update
- Transmission Modeling
- Climate Modeling

June 10, 2022 – Public Meeting (meeting materials provided to stakeholders on June 6, 2022)

- Greenhouse Gas and Renewable Portfolio Standards
- State Policy Update
- Load Forecast Development

- Interconnection Options
- Supply-Side Resource Alternative Fuels
- 2021 IRP Acknowledgment Update
- Stakeholder Feedback

July 14, 2022 – Public Meeting (meeting materials provided to stakeholders on July 11, 2022)

- Draft Load Forecast Update
- Draft Private Generation Study
- Draft Distribution System Planning
- Renewable Portfolio Standards
- Stakeholder Feedback
- Ozone Transport Rule Update

September 1-2, 2022 – General Public Meeting (meeting materials provided to stakeholders on August 29, 2022)

Day One

- Inflation Reduction Act
- Supply Side Resource Table
- Existing Thermal Resource Options
- Transmission Modeling
- Price Forecasting
- Customer Preference
- Qualifying Facility Renewal
- Conservation Potential Assessment Draft Results

Day Two

- Conservation Potential Assessment Draft Results—Part II
- Stakeholder Feedback
- Market Reliance Update
- Oregon and Washington Update
- Generation Transition Equity and Justice
- Offshore Wind Workshop
- Hydro Forecasting Under Climate Change

October 13, 2022 – General Public Meeting (meeting materials provided to stakeholders on October 10, 2022)

- Supply-Side Resource Escalation
- Coal and Gas Modeling Options
- Regional Haze Update
- Load Forecast Update
- Transmission Upgrade Options
- Stochastics
- Reliability Assessment
- Portfolio Discussion

- Stakeholder Feedback Update

December 1, 2022 – General Public Meeting (meeting materials provided to stakeholders on November 28, 2022)

- Conservation Potential Assessment
- State Allocation and MSP Status Update
- Transmission Interconnection: Cluster Study 2 Results
- Initial Risk and Reliability Study Plan
- State Policy Update
- Stakeholder Feedback Form Update

January 13, 2023 – General Public Meeting (meeting materials provided to stakeholders on January 10, 2023)

- Extended Day-Ahead Market Update
- 2022 All-Source RFP Update
- Distribution System Planning update
- Transmission and Portfolio Selection Options Update
- Stakeholder Feedback Form Update

February 23, 2023 – General Public Meeting (meeting materials provided to stakeholders on February 20, 2023)

- Expanded Public Comment Opportunities
- Energy Efficiency Bundling
- Modeling Updates
- Forward Price Curve Updates
- Stakeholder Feedback Update

State-Specific Input Meetings

June 7, 2022 – Oregon State Meeting Part 1
June 7, 2022 – Wyoming State Meeting
June 21, 2022 – Oregon State Meeting Part 2
June 22, 2020 – Washington State Meeting
June 29, 2022 – Utah State Meeting
July 28, 2022 – Idaho State Meeting

Stakeholder Comments

For the 2023 IRP, PacifiCorp offered a Stakeholder Feedback Form which provided stakeholders a direct opportunity to provide comments, questions, and suggestions in addition to the opportunities for discussion at public-input meetings. PacifiCorp recognizes the importance of stakeholder feedback to the IRP public-input process. A blank form, as well as those submitted by stakeholders and PacifiCorp's response, can be located on the PacifiCorp website at the IRP comments webpage at: www.pacificorp.com/energy/integrated-resource-plan/comments.html.

As of March 23, 2023, PacifiCorp has received 36 Stakeholder Feedback Forms (including 4 pending forms) with hundreds of questions, comments, and recommendations. 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 2023 IRP development process, including feedback related to process improvements and input assumptions, as well as responding directly to stakeholder questions. So far, Stakeholder Feedback Forms have been received from the following stakeholders:

- ESS, INC
- Renewable Northwest
- SLC Corp
- Utah Division of Public Utilities
- Western Resource Advocates
- Holland & Hart
- Sierra Club
- Utah Clean Energy
- Oregon Public Utilities Commission
- Interwest Energy Alliance
- Powder River Basin Resource Council
- Northwest Energy Coalition
- Fervo Energy
- Washington Utilities and Transportation Commission
- Renewable Energy Coalition
- Western Energy Storage Task Force

A discussion of topics included in the stakeholder feedback forms and how those topics were considered in the IRP are as follows:

IRP Public-Input Meeting Process/General Comments

Utah Division of Public Utilities submitted feedback stating that PacifiCorp must date its response to stakeholder forms, which the Company will continue to practice as a matter of policy.[1] Note that some entries below may appear to anticipate events that have already occurred because they are presented from the perspective of the responses given at that time.

Legislation

A multi-party request asked that PacifiCorp include time and materials in an upcoming 2023 IRP stakeholder presentation to discuss the benefits and opportunities that may be available through the Infrastructure Investment and Jobs Act, and how they may affect resource and transmission planning. PacifiCorp emphasized active collaboration with state jurisdictions, as most of the Infrastructure Investment and Jobs Act funds for grid projects will be allocated to each state. [2]

[1] Feedback Form 007; June 7, 2022
[2] Feedback Form 011; July 11, 2022

Sierra Club submitted a request that PacifiCorp elaborate on the relationship between the Inflation Reduction Act and load forecast assumptions. PacifiCorp responded stating that it has considered energy efficiency components of IRA for the Conservation Potential Assessment (CPA) by incorporating accelerated adoption rates for certain measure types eligible for IRA rebates and tax credits. It is difficult to exactly prescribe energy efficiency adjustments, but the Company did highlight changes for energy efficiency adoption rates at the December 1st PIM (Public Input Meeting) to reflect the IRA provisions noted in this stakeholder form.[3]

Load Forecasting

Western Resource Advocates recommend modeling two emissions reduction trajectories, in lieu of the "medium" and "high" carbon price scenarios, in addition to the social cost and no-cost GHG price assumptions.[4]

The Utah Division of Public Utilities requested an update on the 20-year weather pattern and Bureau of Reclamation Study, citing that the Reclamation study may not represent the most accurate climate change scenario in developing the IRP load forecast for Utah.[5]

Modeling Assumptions

Holland and Hart requested clarification on how PacifiCorp developed the GHG cost methodology and what third party resources were used to develop these costs. PacifiCorp provided this at a subsequent IRP Public Input Meeting and detailed the source and derivation of its assumptions around the social cost of greenhouse gas and assumptions on price of CO2 that are included in the company's IRP.[6]

Western Resource Advocates reiterated the request for information on Jim Bridger modeling, energy mix disclosure, GHG reporting, natural gas resources and hydrogen updates.[7]

Salt Lake City Corporation suggested that PacifiCorp evaluates wind and solar generation at an hourly rate vs. using monthly data. The Company acknowledged these limitations and is continuing to evolve the modeling process. [8]

The Oregon Public Utilities Commission requested that PacifiCorp determine the assumptions used on installation of new AC units, conversion rates and how the daily shape of electric vehicle charging is modeled.[9]

Sierra Club submitted a request inquiring about reliability resources, coal capacity factors. Carbon Capture Utilization and Sequestration (CCUS), load forecast adjustments, Jim Bridger fuel

[3] Feedback Form 030; December 7, 2022
[4] Feedback Form 012; June 23, 2022
[5] Feedback Form 021; September 9, 2022
[6] Feedback Form 013; June 27, 2022
[7] Feedback Form 015; July 11, 2022
[8] Feedback Form 016; July 14, 2022
[9] Feedback Form 019; August 5, 2022

contracts and the Inflation Reduction Act. PacifiCorp responded to this request at length and the response is publicly available on the Company IRP website. [10]

Utah Clean Energy submitted a stakeholder request outlining the following questions pertaining to the Lila Canyon coal mine fire including efforts to extinguish the fire, operational and workforce implications, reliability and fuel risk assumptions and impacts to 2023 IRP Plexos modeling. PacifiCorp responded to the request at length and the response is publicly available on the Company IRP website. [11]

Natrium Demonstration Project

Powder River Basin Resource Council requested updates on Natrium project risk considerations, fuel availability for project longevity and viable waste disposal options. PacifiCorp responded to this request at length and the information is available to the public online. [12]

The Washington Utilities and Transportation Commission submitted feedback noting concerns with the timeline for the release of the 2023 IRP preferred portfolio, modeling updates for the Natrium project following the announcement of a two-year delay and several procedural observations from IRP Public Input Meeting Series. PacifiCorp responded stating that it is the nature of IRP modeling and preparatory work that results must be confirmed before reporting and that all results are dependent upon ongoing work that is also subject to change. In response to emergent conditions which drive IRP timing, such as federal and state legislation, the Company is providing additional opportunities for public feedback after the March 31st filing and plans to file an addendum as needed and responsive to stakeholders.[13]

Natural Gas

Salt Lake City Corporation noted that PacifiCorp should study whether a battery with a grid forming inverter would provide a lower-cost alternative to natural gas spinning reserves. PacifiCorp outlined its position that it considers a wide range of technologies for supply-side resources[14]

The Utah Division of Public Utilities outlined potential concerns concerning stranded cost risks and resource depreciation from conventional natural gas generation and asked to re—evaluate the use of natural gas proxy resources. The Company has since modeled for new natural gas resources in the 2023 IRP.[15]

Utah Clean Energy submitted feedback asking how PacifiCorp will assess the impacts of methane leakage mitigation policies on natural gas portfolio outcomes. PacifiCorp responded by stating that the overall impact of the Methane emissions fee is ~1% or less and therefore negligible in the long-term natural gas price forecast[16]

[10] Feedback Form 029; November 28, 2022
[11] Feedback Form 031; November 23, 2022
[12] Feedback Form 028; October 5, 2022
[13] Feedback Form 035; January 17, 2023
[14] Feedback Form 009; June 16, 2022
[15] Feedback Form 018: July 21, 2022
[16] Feedback Form 023; September 8, 2022

Salt Lake City Corporation submitted feedback insisting that PacifiCorp should consider revising its natural gas price forecast higher in line with the Energy Information Administration short-term energy outlook. PacifiCorp indicated that the plan is to develop a forecast in September 2022 for use in the 2023 IRP, which will incorporate then-current natural gas prices and the latest long-term expectations. [17]

Plexos

Utah Division of Public Utilities Requests Company updates its Supply Side table with current operating and costs characteristics of natural gas fueled generation resources and allow the model to endogenously select natural gas generating resources as proxy resources, as it has done in the past. In the 2021 IRP, PacifiCorp ran an analysis which included options for new gas and for the 2023 IRP, the company has also assessed viable options for the inclusion of new gas in its base modeling. [18]

Reliability Assessment

Sierra Club noted several observations pertaining to reliability modeling, the Inflation Reduction Act, and a potential reduction in Transmission costs via the Energy Infrastructure Reinvestment (EIR) program. PacifiCorp responded stating that many of these observations would be fully addressed once the Company provides a comprehensive IRP by the March 31, 2023, filing date.[19]

Renewable Energy Resources

The Renewable Energy Coalition submitted a request outlining PacifiCorp's compliance with Oregon Public Utility Commission Order No. 22-178 and relevant data including the current QF renewal and success rate at varying capacities. PacifiCorp responded by posting supporting documentation on the Company Public Input Meeting website titled "QF Extension History", which provides an inventory of PacifiCorp qualifying facilities with other pertinent information. For supplemental data relating to qualifying facilities, this party was also directed to Oregon dockets LC-77 (2021 IRP) and LC-70 (2019 IRP).[20]

Resource Adequacy

Utah Clean Energy submitted a request that PacifiCorp develop three demand-side management sensitivities utilizing a low, medium, and high method of measurement. With the above feedback considered PacifiCorp instead utilizes a bottom-up modeling approach, which is better suited to adjustments to inputs for the purpose of informing sensitivities.[21]

[17] Feedback Form 009; June 16, 2022
[18] Feedback Form 010; July 7, 2022
[19] Feedback Form 034; January 18, 2023
[20] Feedback Form 032; January 3, 2023
[21] Feedback Form 017; July 21, 2022

State Energy Policy

Sierra Club requested updates on the Natrium Project, emissions profiles and state policy updates as they relate to the 2021 IRP acknowledgment, greenhouse gas reporting, Renewable Portfolio Standards, load forecast updates and compliance with the Washington Clean Energy Transformation Act (CETA).[22]

Washington Utilities and Transportation Commission Staff emphasized the statutory obligation for Washington utilities to incorporate the social cost of greenhouse gas into Washington allocated resource carbon cost assumptions. PacifiCorp responded by stating it is not aware of any language in RCW 19.280.030(3) and WAC 480-100-605 that requires utilities to include the SCGHG as their base carbon cost price-policy assumption for Washington-allocated resources.[23]

Supply-side Resource Costs/Supply-side Resource Table

ESS Inc requested an update from PacifiCorp on what changes are being made to the IRP modeling to determine marginal values of long-duration flow battery storage. The Company informed this party that it is commissioning a study of the cost and performance characteristics of energy storage and expects the study to include information specific to long duration flow batteries[24]

Renewable Northwest submitted a request that PacifiCorp consider DC-coupled solar + storage as well as other additional battery storage durations (medium and long-duration) as part of the supply-side resource table and subsequent IRP modeling. The Company responded indicating that Proxy resource modeling in the 2023 IRP is intended to be representative of costs and operational characteristics across a range of configurations and at this time is based on AC configuration but does not preclude other constructs from participating in all-source requests for proposals. [25]

Fervo Energy submitted a supply-side resources feedback outlining new cost assumptions that geothermal is becoming a less cost-prohibitive resource option that has the potential to create new jobs. In line with regulatory precedent, PacifiCorp remains committed to pursuing least- cost, least-risk preferred portfolio outcomes including geothermal when economically competitive.[26]

Renewable Northwest submitted feedback requesting updated transmission capacity metrics, offshore wind costs and recent modeling assumptions. PacifiCorp responded by stating that it has added 1,000 MW of offshore wind resources to the supply-side table among other more detailed information provided in this stakeholder form. [27]

The Western Energy Storage Task Force recommended the use of a specified forecast for utility-scale battery storage resources and proposed revising price modifications. PacifiCorp responded and re-affirmed that the costs presented in the September 1st Public Input Meeting do not include tax incentives implemented in the Inflation Reduction Act. Additional supply-side table reporting

[22] Feedback Form 014; July 1, 2022
[23] Feedback Form 024; September 20, 2022
[24] Feedback Form 001; February 24, 2022
[25] Feedback Form 002; March 3, 2022
[26] Feedback Form 020; August 23, 2022
[27] Feedback Form 022; September 14, 2022

will identify costs after accounting for tax incentives and all tax incentives are being accounted for in the 2023 IRP modeling process. The information about tax incentives presented to date is consistent with Table 7.1 in PacifiCorp's 2021 IRP. Resource information inclusive of tax incentives was provided in Table 7.2 of PacifiCorp's 2021 IRP and comparable information will be provided for the 2023 IRP.[28]

Salt Lake City Corporation submitted a request for the inclusion of a supply-side long-duration storage option with characteristics similar to the iron air battery announced earlier in the year. The Company responded by stating that it is considering longer duration energy storage similar to Form Energy Iron Air Battery in the 2023 IRP. PacifiCorp is commissioning a study of the cost and performance characteristics of energy storage and expects the study to include cost information specific to long duration flow batteries.[29]

Transmission

The Utah Division of Public Utilities requested supplemental study information and transmission topology, specifically referring to the Kiewit study on natural gas and hydrogen and requesting further information regarding why the Jim Bridger coal plant was moved to the PAC-east balancing authority. PacifiCorp responded directly to this stakeholder request and did not publish the response due to sensitivities around the Kiewit study.

The Interwest energy alliance inquired about whether or not PacifiCorp reviews the potential for reconductoring with advanced conductors, grid enhancing technology or advanced transmission technologies. PacifiCorp responded by saying it considers reconductoring with advanced conductors such as ACCC and ACSS if this provides a solution to thermal issues that are observed during outage conditions for regular studies such as Cluster Studies, Transmission Planning Assessment studies TPL001-4 and others[30]

Contact Information

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

PacifiCorp requests any informal request be sent to the following address or email.

PacifiCorp
IRP Resource Planning Department
825 N.E. Multnomah, Suite 600
Portland, Oregon 97232

Email Address:
IRP@PacifiCorp.com

[28] Feedback Form 027; October 27, 2022
[29] Feedback Form 003; May 12, 2022
[30] Feedback Form 033; January 10, 2023

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 2023 Integrated Resource Plan (IRP). In addition, it provides information on the economic DSM selections in the 2021 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 2023-2042

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 2023-2042,[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 2023 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, differentiated by two primary characteristics: reliability and customer choice. These resource classifications can be defined as: demand response (e.g., a firm, capacity focused resource such as direct load control), energy efficiency (e.g., a firm energy intensity resource such as conservation), demand side rates (DSR) (e.g., a non-firm, capacity focused resource such as time of use rates), and 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 behavioral-based activities involve greater customer

[1] PacifiCorp's Demand-Side Resource Potential Assessment for 2023-2042, completed by AEG, can be found at: www.pacificorp.com/energy/integrated-resource-plan/support.html.

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 16,100 customers were participating in metered time-of-day and time-of-use programs as of December 31, 2022.

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.2 provides an overview of DSM related Wattsmart Outreach and Communication activities (Class 4 DSM activities) by state.

[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.pacificorp.com/environment/demand-side-management.html.
[3] Funds for low-income weatherization services are forwarded to Oregon Housing and Community Services.

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	√	√	√	√	√	√
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	√	√	√	√	√	√

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

Table D.2 – Current Wattsmart Outreach and Communications Activities

Wattsmart 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)	√	√	√	√	√	√
Wattsmart Workshops and Community Outreach	√	√	√	√	√	√
BE *wattsmart*, 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 the 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 December 19, 2022, the Commission issued approved the company's Biennial Budget Advice Letter (BBAL) Filing 697E to administering its energy efficiency programs through 2024. 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 2023 IRP preferred portfolio[5].

[4] The Company's 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 –First Year Demand Response Resource Selections (2023 IRP Preferred Portfolio)[6]

Resource	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
DR Summer - ID	0.0	0.0	4.1	9.0	5.7	1.0	0.3	0.3	0.3	0.0
DR Summer - UT	0.0	8.5	27.6	23.3	28.7	20.6	12.1	10.6	13.9	0.0
DR Summer - WY	0.0	0.0	14.3	0.9	21.8	3.5	0.1	0.0	0.1	0.0
DR Winter - ID	0.0	0.4	1.0	1.1	0.6	0.2	0.0	0.0	0.0	0.0
DR Winter - UT	0.0	0.5	6.7	5.6	1.7	1.9	0.0	0.0	0.0	0.0
DR Winter - WY	0.0	0.0	9.8	14.3	7.3	4.3	0.4	0.5	0.3	0.0
DR Summer - CA	0.0	0.0	2.7	1.5	1.4	0.5	0.1	0.1	0.2	0.0
DR Summer - OR	47.0	1.9	33.5	20.6	44.6	16.0	12.3	4.0	5.5	0.0
DR Summer - WA	24.5	2.9	7.3	7.5	10.7	3.7	2.0	0.0	1.8	0.0
DR Winter - CA	0.0	0.0	1.2	1.7	0.3	1.1	0.0	0.0	0.0	0.0
DR Winter - OR	0.0	14.7	37.0	20.2	9.0	23.3	0.0	0.0	0.0	0.0
DR Winter - WA	0.0	9.7	7.1	3.6	1.2	5.1	0.0	0.0	0.0	0.0
Resource	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**
DR Summer - ID	-	-	-	-	-	37.3	0.4	0.3	-	-
DR Summer - UT	-	-	-	-	-	113.2	14.8	15.5	-	-
DR Summer - WY	-	-	-	-	-	7.4	0.1	0.1	-	-
DR Winter - ID	-	-	-	-	-	-	-	-	-	-
DR Winter - UT	-	-	-	-	-	-	-	-	-	-
DR Winter - WY	-	-	-	-	-	0.4	-	-	-	-
DR Summer - CA	-	-	0.2	0.0	-	3.8	0.1	0.1	-	-
DR Summer - OR	-	-	3.6	0.0	0.0	57.3	3.3	3.0	-	-
DR Summer - WA	-	-	0.8	-	-	13.2	0.7	0.5	-	-
DR Winter - CA	-	-	-	-	-	-	-	-	-	-
DR Winter - OR	-	-	-	-	-	-	-	-	-	-
DR Winter - WA	-	-	2.4	-	-	-	-	-	-	-

Table D.4 – First Year Energy Efficiency Resource Selections (2023 IRP Preferred Portfolio)

Energy Efficiency Energy (1st Year Savings MWh) Selected by State and Year										
State	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
CA	2,425	2,704	3,033	3,503	4,200	4,703	4,540	3,623	4,292	3,093
OR	164,891	188,547	198,401	157,042	169,924	165,387	128,721	138,568	187,201	96,943
WA	53,112	39,612	48,328	32,771	37,248	41,527	41,936	42,014	42,060	38,434
UT	266,500	266,661	273,564	292,860	318,621	348,920	421,605	434,966	722,976	286,797
ID	12,000	14,884	17,573	21,828	24,912	26,756	28,528	28,069	34,929	22,065
WY	44,204	38,468	55,003	55,087	58,854	59,351	66,738	69,934	93,500	61,036
Total System	543,132	550,876	595,902	563,091	613,759	646,644	692,068	717,174	1,084,958	508,368

Energy Efficiency Energy (1st Year Savings MWh) Selected by State and Year										
State	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**
CA	2,968	2,941	2,712	4,291	5,027	4,365	3,931	3,088	1,045	1,369
OR	113,012	116,620	70,673	89,040	157,073	85,104	84,261	58,890	31,439	150,622
WA	37,560	36,741	35,895	35,228	35,735	30,881	27,574	27,252	17,639	16,641
UT	324,918	335,953	351,377	486,426	753,213	307,927	344,013	376,481	382,259	513,035
ID	26,134	28,410	29,288	30,150	29,760	23,177	21,277	22,636	20,693	17,551
WY	59,034	61,187	59,279	81,096	74,415	50,116	46,386	54,210	39,728	68,544
Total System	563,626	581,852	549,224	726,231	1,055,223	501,570	527,442	542,557	492,803	767,762

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] A portion of cost-effective demand response resources identified in the 2023 preferred portfolio in 2023 for Oregon and Washington represent planned volumes expected to be acquired in 2023 PacifiCorp will pursue all cost-effective demand response resources identified as incremental to resources offered through approved programs.

APPENDIX E – SMART GRID

Introduction

Smart grid is the application of advanced communications and controls to the electric power system. As such, a wide array of applications can be defined under the smart grid umbrella. PacifiCorp has identified specific areas for research that include technologies such as dynamic line rating, phasor measurement units, distribution automation, advanced metering infrastructure (AMI), automated demand response and other advanced technologies. PacifiCorp has reviewed relevant smart grid 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. This network must have relevant speed, reliability, and security to support applications such as current real-time WEIM (optimizes the energy imbalances throughout the West) by transferring energy between participants in 15-minute and 5-minute intervals throughout the day.

PacifiCorp has planned to build on the success of real-time energy market innovation by joining the new Western day-ahead market, (EDAM), developed by the California Independent System Operator (CAISO). A modernized western energy market is a key component of PacifiCorp's strategy to connect and optimize the West's abundant and diverse energy resources to deliver the lowest cost and most reliable pathway to a net-zero energy future. PacifiCorp is committed to advancing innovation in markets and new energy technologies to meet its commitment to affordability and reliability while supporting its communities throughout the energy transition.

PacifiCorp has focused on those technologies that present a positive benefit for customers and has implemented functions such as advanced metering, dynamic line rating, and distribution automation. This will 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 the value of 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 smart grid applications and technologies. As technology advances and development continues, PacifiCorp can improve cost estimates and benefits of smart grid technologies that will assist in identifying the best suited technologies for implementation.

Transmission Network and Operation Enhancements

Dynamic Line Rating

Dynamic line rating 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 online-loading calculations given a set of worst-case weather assumptions, such as high ambient temperatures and very low wind speeds. Dynamic line rating (DLR) allows an increase in current-carrying capacity of transmission lines, when more favorable weather conditions are present, a without compromising safety. DLR has become increasingly relevant with higher shares of variable renewable energy (VRE) in the power system. By seeking to increase the ampacity of transmission lines, it provides economic and technical benefits to all involved. FERC NOPR (RM21-17-000) is calling to fully consider dynamic line ratings 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 directly linked to increased wind power generation and increased transmission ratings. A dynamic line rating system is used to determine 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. As a result of this project, the Aeolus West Western Electricity Coordinating Council (WECC) non-simultaneous path rating was increased. The DLR system on the Platte – Standpipe 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 – Difficulty – Shirley Basin 230 kV line as part of the Gateway Segment D.1 Project. The Dave Johnston- Amasa – Difficulty – Shirley Basin 230 kV line connects two areas with a high penetration of wind generation resources and 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 area and moderate to low winds in the southeast 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.

Dynamic line rating will be considered for all future transmission needs as a means for increasing capacity in relation to traditional construction methods. Dynamic line rating is only applicable for thermal constraints and only provides additional site-dependent capacity during finite time periods, and it may or may not align with expected transmission needs of future projects. PacifiCorp will continue to look for opportunities to cost-effectively employ dynamic line rating systems similarly to the one deployed on the Standpipe – Platte 230 kV transmission line...

Digital Fault Recorders / Phasor Measurement Unit Deployment

To meet compliance with the North American Electric Reliability Corporation (NERC) MOD-033-1 and PRC-002-2 standards, PacifiCorp has installed over 100 multifunctional digital fault recorders (DFR) which include phasor measurement unit (PMU) functionality. The installations are at key transmission and generation facilities throughout the six-state service territory, generally placed on WECC identified critical paths. PMUs provide sub-second data for voltage and current phasors, which can be used for MOD-033-1 event analysis and model verification. DFRs have a shorter recording time with higher sampling rate to validate dynamic disturbance modelling per PRC-002-2. The DFR/PMUs will 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 engineers to validate system models has been completed.

Transmission planners will 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 prior to, during, and following an event. Differences in simulated versus actual system performance will then be evaluated to allow for enhancements and corrections to the system model.

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 will continually 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 California Independent System Operator's (CAISO) Reliability Coordinator West to share data as appropriate.

Distribution Automation and Reliability

Distribution Automation

Distribution automation encompasses a wide field of smart grid technology and applications that focus on using sensors and data collection on the distribution system, as well as automatically adjusting the system to optimize performance. Distribution automation can also provide improved outage management with decreased restoration times after failure, operational efficiency, and peak load management using distributed resources and predictive equipment failure analysis using complex data algorithms. PacifiCorp is working on distribution automation initiatives focused on improved system reliability through improved outage management and response.

In Oregon, PacifiCorp identified 40 circuits on which cost benefit analyses were performed. 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 through 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 pre-deployment distribution automation 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 suited well 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. The fiber infrastructure was deployed in Q4 2022, and the Company now has complete FLISR capability with the Devil's Lake DA system.

Based on that experience additional two additional automation projects were initiated in Portland and Medford, relying on private fiber optic communications (in a manner very similar to how transmission assets would be monitored) Engineering and construction are in progress and commissioning during 2022 is anticipated.

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 advanced substation metering project enabled installation of enhanced monitors at more than fifty distribution circuits in the state of Utah. 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

In 2017, PacifiCorp filed the Energy Storage Potential Evaluation and Energy Storage Project proposal with the Public Utilities Commission or Oregon. This filing was in alignment 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 micro grid 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 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 one dozen feasibility studies have been delivered across the service territory of the two states. Two ESS systems have been installed in California with a third approved; two grant submissions in Oregon are in the final stage of application approval. As part of the Company's forthcoming first Clean Energy Plan (CEP) with the Oregon Public Utilities Commission. PacifiCorp presented a strawman proposal to expand the Oregon pilot into a larger program that could provide grant funding for the installation of solar as well as battery storage. The Program would continue to provide feasibility studies and technical support to interested facilities. The Company plans to elicit feedback on the proposal through CEP stakeholder channels and determine next steps by the end of 2023.

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

In 2018, PacifiCorp transitioned to the automatic dispatch of the residential air conditioner (A/C) program in Utah, utilizing two-way communication devices to respond to frequency dispatch signals. Known as Cool Keeper this frequency dispatch innovation is a grid-scale solution using fast-acting residential demand response resources to support the bulk power system. Some utilities use generating resources to perform this function, but as higher levels of wind and solar resources are added, additional balancing resources are required. The Cool Keeper system provides over 200 MWs of operating reserves to the system through the control of more than 108,000 A/C units.

In 2021, PacifiCorp released a Request for Proposals for Demand Response resources. The Company has used the responses to incorporate the cost of Demand Response programs more accurately in the 2021 Integrated Resource Plan. In 2022 and 2023, PacifiCorp contracted with vendors solicited during the demand response RFP and filed for programs in Oregon, Washington, Idaho, Utah, and Wyoming. These programs included new Irrigation and Commercial and Industrial curtailment programs.

Dispatchable Customer Storage Resources

Based on the learnings from Rocky Mountain Power's partnership with Soleil Lofts and Sonnen in 2018, the company developed the Wattsmart Battery Program which was approved in Utah October 2020 and in Idaho April 2022. This innovative demand response program allows the

Company to manager 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 will allow the company to maximize renewable energy when it's needed to support the electrical gird. The program is experiencing exponential growth and has over 2,700 residential batteries and 8 commercial batteries participating as of Q1 2023.

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 distribution automation 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 656,000 meters. Interval energy usage data is provided to customers via the Pacific Power website and mobile app. 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 involves upgrading the head-end software and installation of the Field Area Network (FAN) and approximately 240,000 new Itron Riva AMI meters for most customer classification and 20,000 Aclara AMI meters for the Utah rate schedule 136 private generation accounts. This solution will utilize 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 will replace 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.

Meter and FAN system installations in Idaho are substantially complete. Utah FAN and meter installations are underway with completion scheduled for Q4 2023. Costs and benefits associated with the AMI project will be tracked and analyzed and will be evaluated against the business case projections after completion.

Financial analyses to extend AMI solutions to Washington and Wyoming were performed in 2019 and 2020, respectively. The analyses determined that moving these states to an AMI solution was not cost effective at this time. The Company is currently updating the business case for both states. The review should be completed by Q2 2023.

Financial analyses to extend AMI solutions to Washington and Wyoming were performed in 2019 and 2020, respectively. These states utilize the same AMR meter technology as Utah and can be leveraged to provide extended functionality and value. The analyses determined that moving these states to an AMI solution is not cost effective at this time but has improved slightly over previous analyses. The Company will continue to review and evaluate the business case and cost effectiveness for these states routinely over the next few years.

Outage Management Improvements

PacifiCorp advanced a new module in its OMS which allows for 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 which 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. The same outage management systems (OMS) will be used for Utah and Idaho when those projects are complete. Company's system operations organization has begun using 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 the system operations with more flexibility to identify and respond to outages.

The intelligent line sensors will be installed on distribution circuits that will provide service to critical facilities. For this project, critical facilities have been defined as major emergency facility centers such as hospitals, trauma centers, police, and 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 is was completed in December 2021, concurrent with the completion of the AMI project.

Future Smart Grid

The Company continues to develop a strategy to attain long-term goals for grid modernization and smart grid-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 smart grid technologies and determine viability and applicability of implementation to the system, and as tipping points to broader implementation occur it's expected these will be communicated through a variety of methods, including this IRP as well as other regulatory mechanisms relevant to that state.

APPENDIX F – FLEXIBLE RESERVE STUDY

Introduction

While PacifiCorp had significant increases in both wind and solar capacity on its system in 2021, there has not yet been time to collect and assess sufficient historical data that includes this expanded output. Therefore, for the 2023 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 2023 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 "the 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]

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[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*

(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 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 Energy Imbalance Market (EIM) operated by the California Independent System Operator Corporation (CAISO).

The methodology in the FRS is like that employed in PacifiCorp's 2019 IRP but has been enhanced in two areas.[6] First, the historical period evaluated in the study has been 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 has been 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.

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").

[6] 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

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 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 - 2023 Flexible Resource Costs as Compared to 2021 Costs, $/MWh

	Wind 2023 FRS (2022$)	Solar 2023 FRS (2022$)	Wind 2021 FRS (2022$)	Solar 2021 FRS (2022$)
Study Period	2025-2042	2025-2042	2023-2040	2023-2040
Flexible Resource Cost	$1.38	$1.59	$1.58	$1.32

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.[7] Regulation reserve is capacity that PacifiCorp holds available to ensure compliance with the NERC Control Performance Criteria in

[7] NERC Standard BAL-002-WECC-3 – Contingency Reserve: https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-002-WECC-3.pdf

BAL-001-2.[8] Frequency response reserve is capacity that PacifiCorp holds available to ensure compliance with NERC standard BAL-003-2.[9] Each type of operating reserve is further defined below.

Contingency Reserve

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

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

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

Ramp Rate: Only up capacity available within ten minutes can be counted as contingency reserve. This can include "spinning" resources that are online and immediately responsive to system frequency deviations to maintain compliance with frequency response obligations under BAL-003-1.1, as well as from "non-spinning" resources that do not respond immediately, though they must still be fully deployed in ten minutes.[10]

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…*

[8] NERC Standard BAL-001-2 – Real Power Balancing Control Performance: https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-001-2.pdf
[9] NERC Standard BAL-003-2 — Frequency Response and Frequency Bias Setting: https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-003-2.pdf
[10] 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.

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 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 2022 frequency response obligation was 25.3

MW/0.1Hz for PACW, and 63.5 MW/0.1Hz for PACE.[11] PacifiCorp's combined obligation amounts to 88.8 MW for a frequency drop of 0.1 Hz, or 266.4 MW for a frequency drop of 0.3 Hz.

The performance measurement for contingency reserve under the Disturbance Control Standard (BAL-002-3)[12], 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

[11] 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_OY2022-document(002).pdf

[12] 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

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 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.[13]

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

[13] 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.

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.

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.[14] Wind and solar, in comparison to load, often have larger upward and downward fluctuations in output that impose significant and sometimes unforeseen challenges when attempting to maintain reliability. For example, as recognized by FERC in Order No. 764, "Increasing the relative amount of [VERs] on a system can increase operational uncertainty that the system operator must manage through operating criteria, practices, and procedures, *including the commitment of adequate reserves*."[15] 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."[16]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.

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

Regulation Reserve Data Analysis and Adjustment

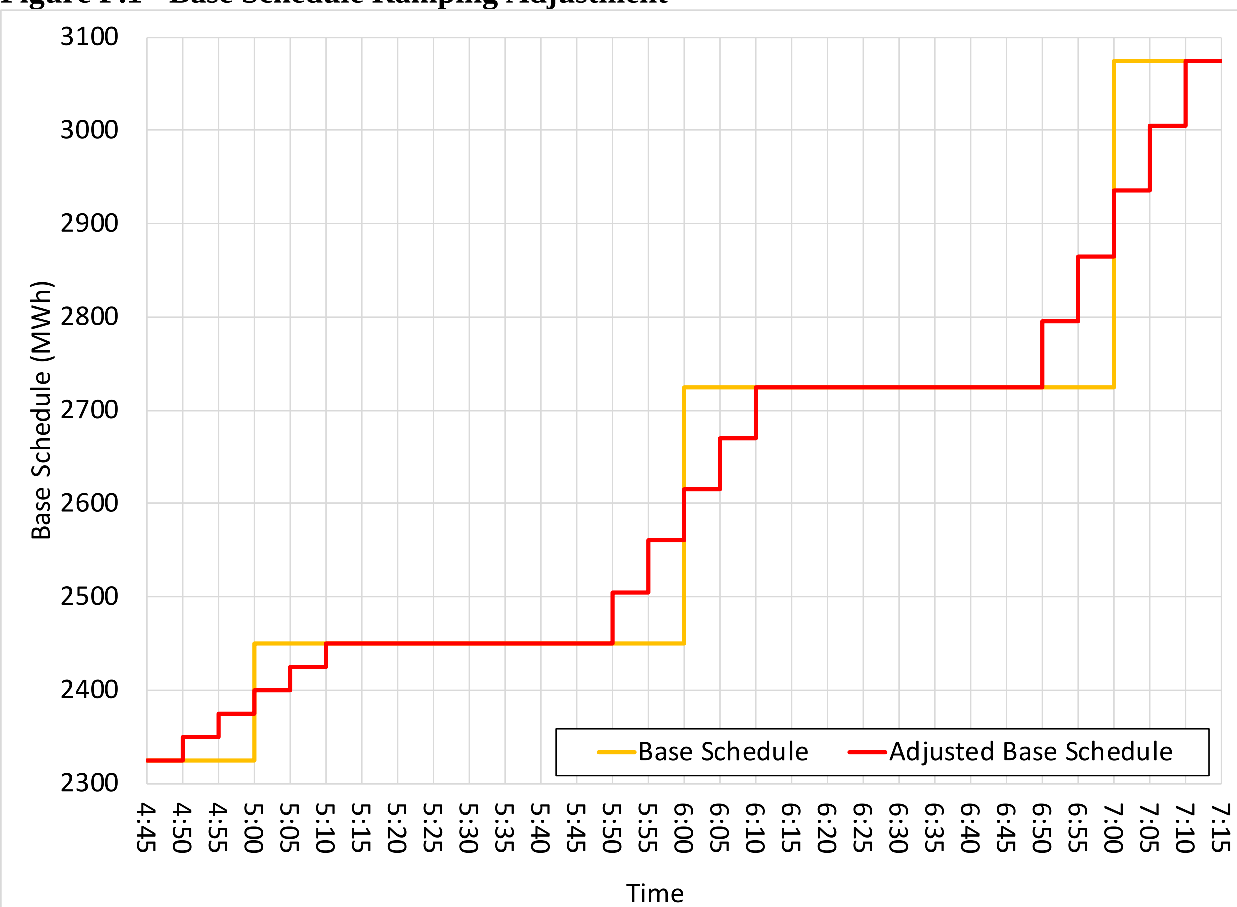
Overview

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 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.[17]

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 (i.e., spinning and supplemental 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

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

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.[18] The regulation reserve requirement is not defined by a simple formula, but instead is the amount of reserve required by each BAA to meet specified control performance standards. Requirement two of BAL-001-2 defines the compliance standard as follows:

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

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

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

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

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

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

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

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

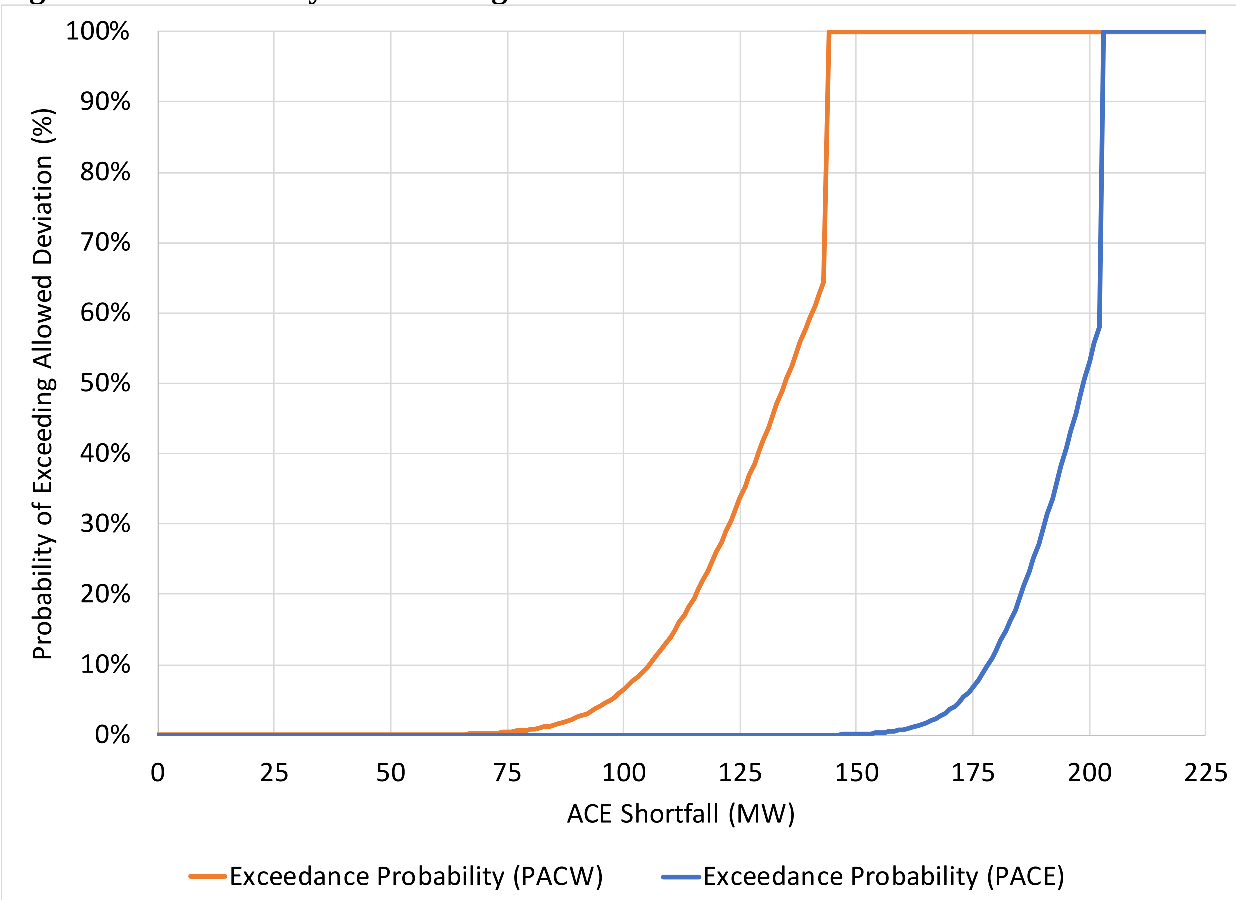
Even if insufficient regulation reserve capability is available to compensate for a thirty-minute sustained deviation, a violation of BAL-001-2 does not occur unless the deviation also exceeds the Balancing Authority ACE Limit.

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.[19,20] This cap is reflected in Figure F.2.

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

[19] "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

[20] "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

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

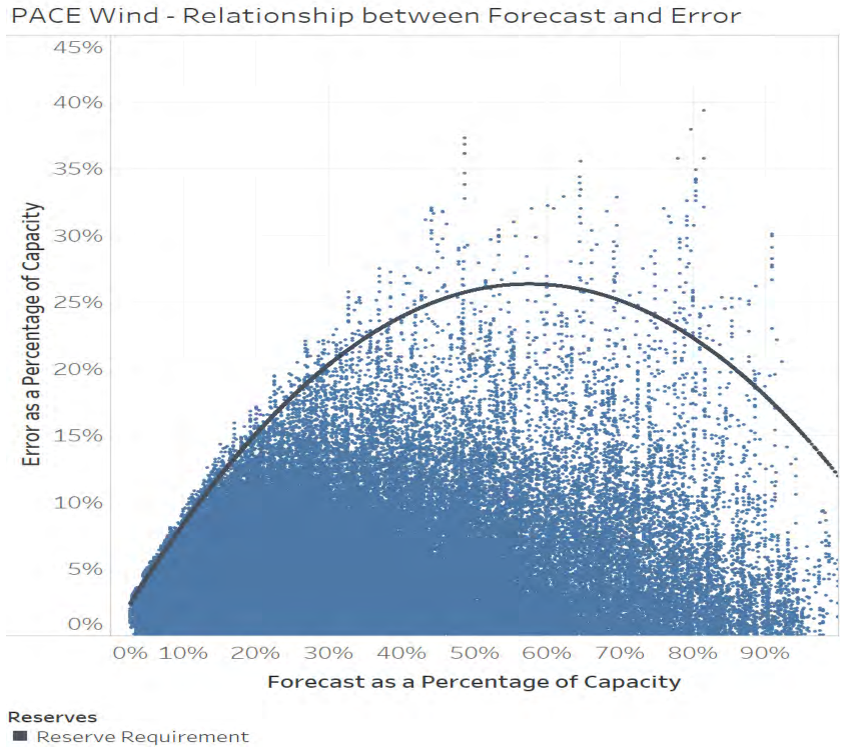


Figure F.4 - Wind Regulation Reserve Requirements by Forecast Capacity Factor - PACW

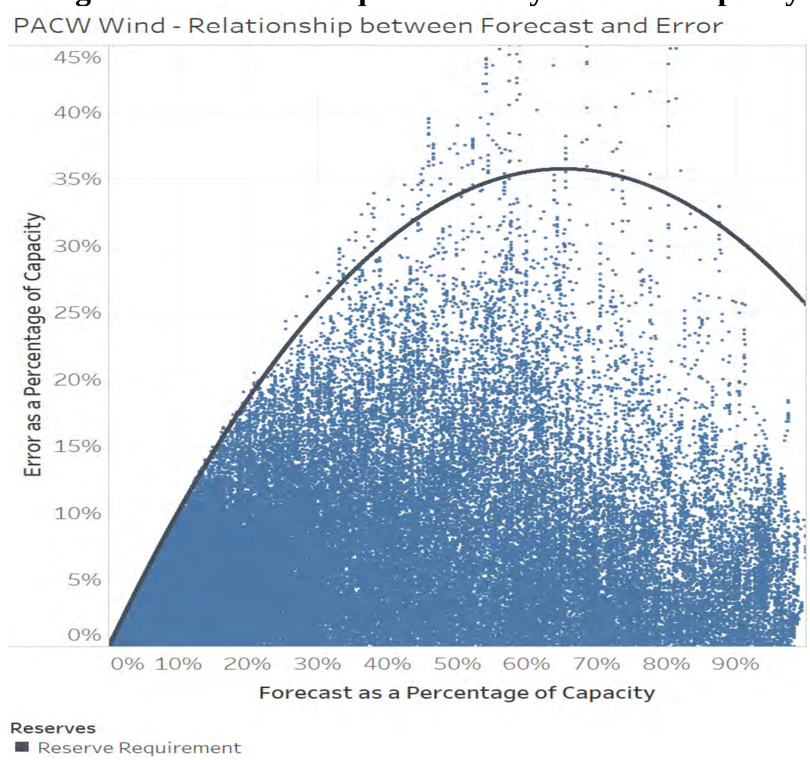


Figure F.5 - Solar Regulation Reserve Requirements by Forecast Capacity Factor - PACE

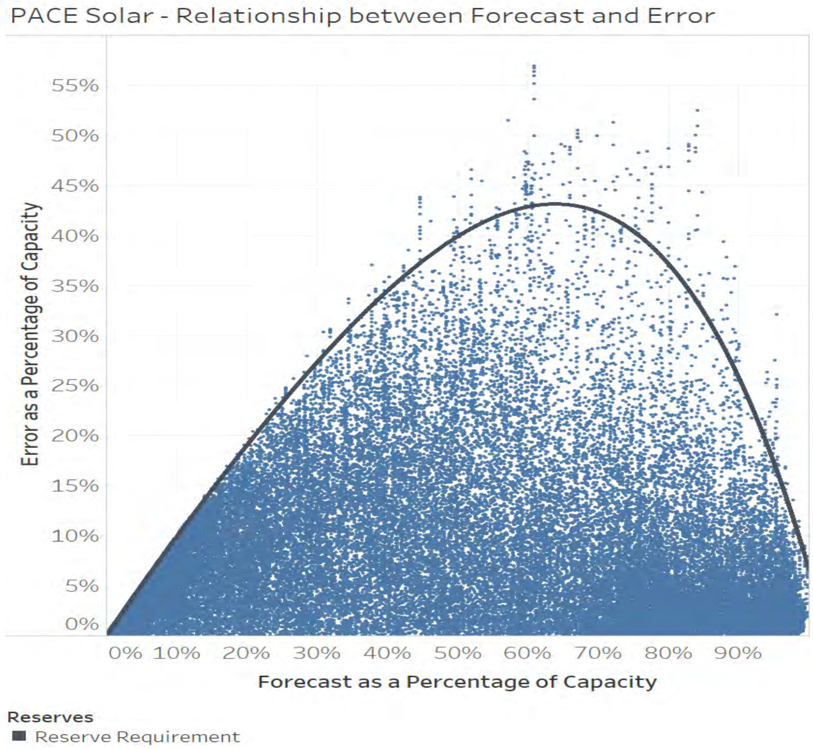


Figure F.6 - Solar Regulation Reserve Requirements by Forecast Capacity Factor - PACW

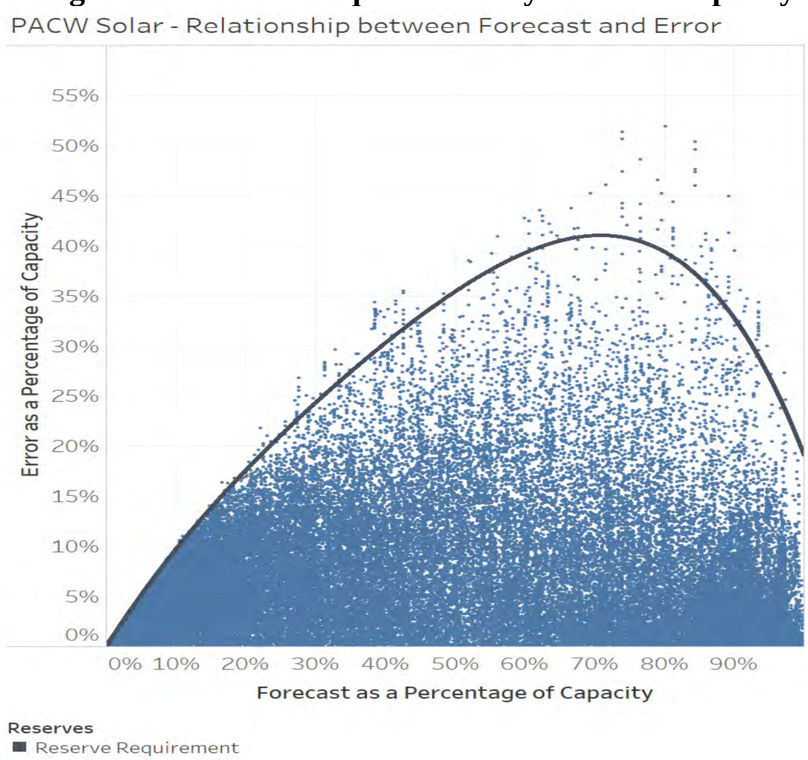


Figure F.7 – Non-VER Regulation Reserve Requirements by Capacity Factor - PACE

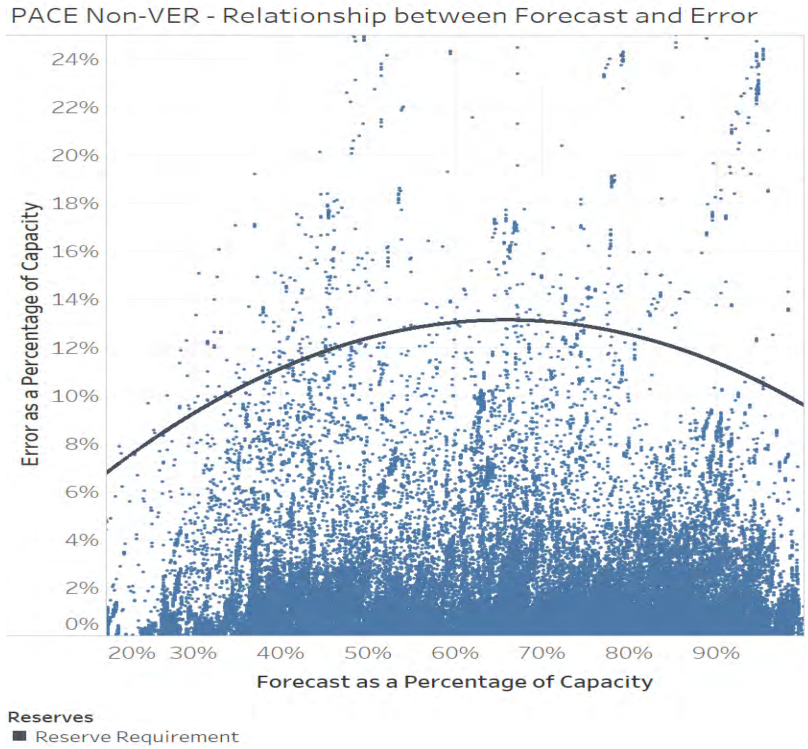


Figure F.8 – Non-VER Regulation Reserve Requirements by Capacity Factor - PACW

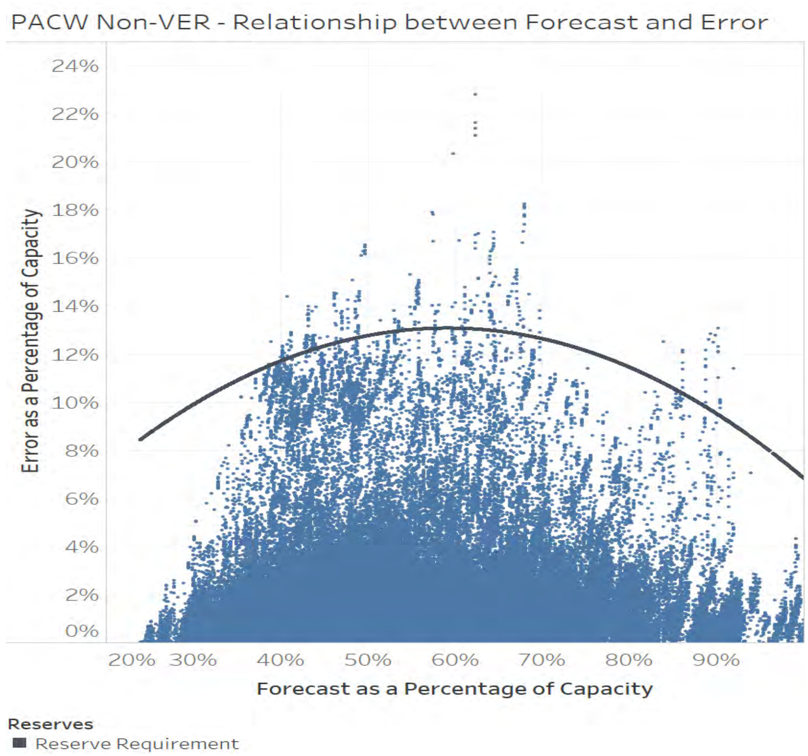


Figure F.9 – Stand-alone Load Regulation Reserve Requirements - PACE

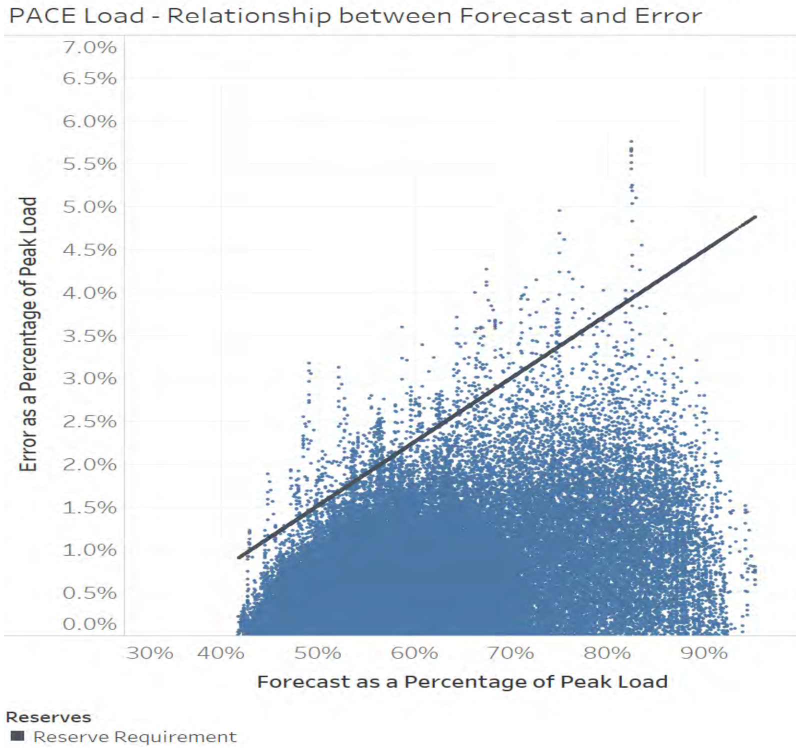
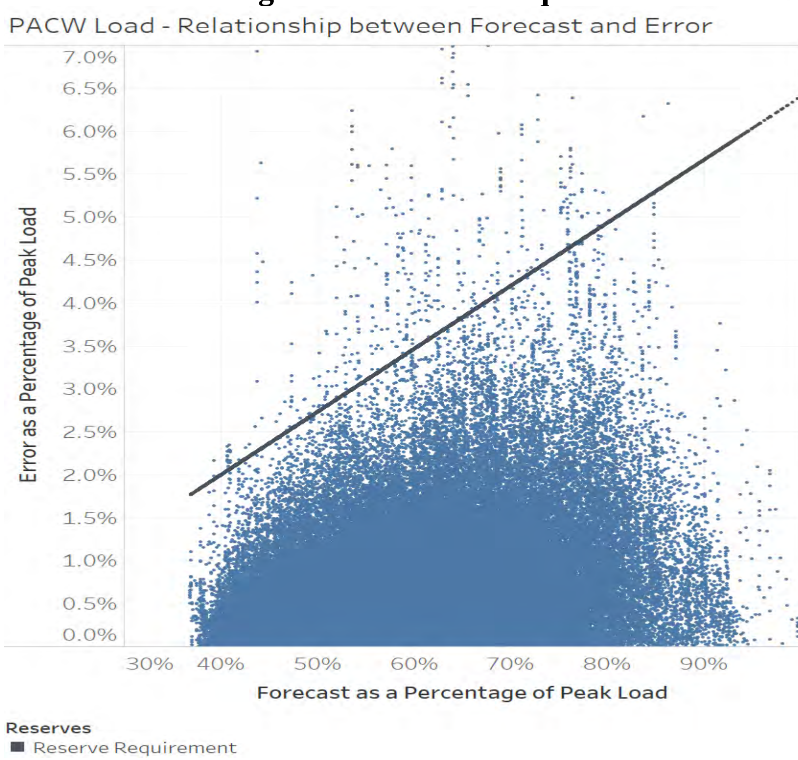


Figure F.10 – Stand-alone Load Regulation Reserve Requirements - PACW



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. Several additional participants have since joined the EIM, 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.7 and Table F.8 for PacifiCorp East and PacifiCorp West, respectively.

Table F.7 – PacifiCorp East Diversity by Portfolio Composition

(% Reduction vs. Stand-alone Requirements)

East Wind Capacity MW	%	50% (428 MW)	100% (855 MW)	166% (1,462 MW)	329% (2,502 MW)	493% (3,542 MW)	656% (4,582 MW)	820% (5,622 MW)	983% (6,662 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%

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	West Wind Capacity %	West Solar 50% (111 MW)	West Solar 100% (221 MW)	West Solar 166% (321 MW)	West Solar 329% (1,041 MW)	West Solar 493% (1,761 MW)	West Solar 656% (2,481 MW)	West Solar 820% (3,201 MW)	West Solar 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%		$\boxed{42.4\%}$	42.9%	48.6%	49.3%	47.7%	46.2%	44.4%
363	50%			41.7%	47.1%	49.8%	47.4%	45.0%	43.2%

West Solar Capacity

2018-2019 Actual Wind and Solar Capacity

After portfolio selection is complete, regulation reserve requirements are calculated specific to a portfolio's load, wind, and solar resources in each year. The hourly regulation reserve requirement varies as a function of annual peak load net of energy efficiency selections as well as total wind and solar capacity. The regulation reserve requirement also varies based on the hourly load net of energy efficiency and hourly wind and solar generation values. Diversity exponents specific to the wind and solar capacity in each year are applied by hour and season, by interpolating among the scenarios illustrated in Tables F.7 and 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 2023 IRP, PacifiCorp prepared a PLEXOS scenario that reflected the final regulation reserve requirements, consistent with the Company's existing wind and resources plus selections in the preferred portfolio. Hourly regulation reserve prices were reported from this study.

Wind Integration

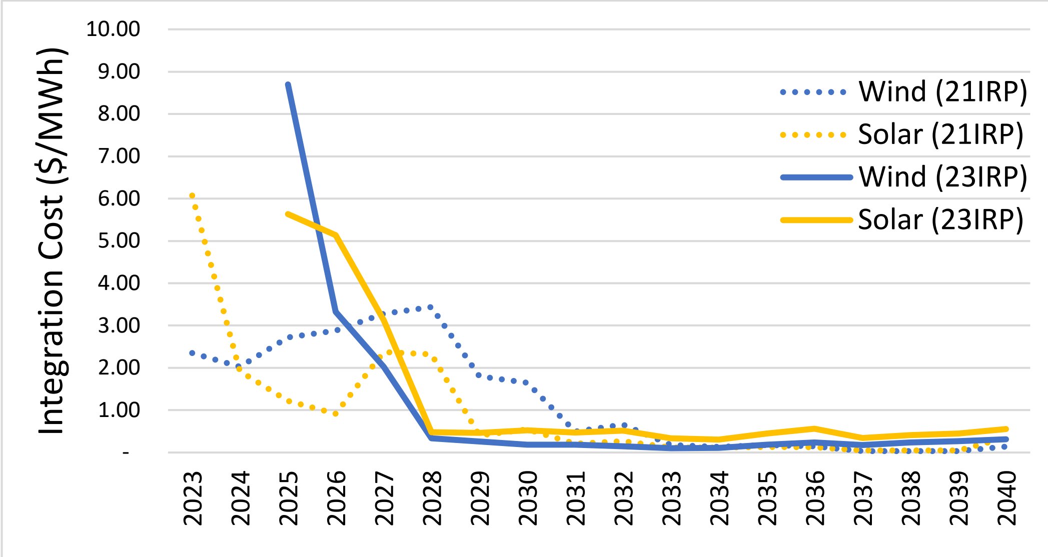
The wind reserve case uses the 2021 FRS methodology to recalculate the wind reserve requirement for a portfolio with 5 MW more wind resources starting in the first-year proxy resources are potentially available and extending to the end of the IRP study horizon (2025-2042). The change in resources is 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 16% 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 potentially available and extending to the end of the IRP study horizon (2025-2042). 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 10% 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



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 2023 through 2042, 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 include three distinct components and are modeled separately in the 2023 IRP: 10-minute spinning reserve requirements, 10-minute non-spinning reserve requirements, and 30-minute regulation reserve requirements. The average reserve requirements for PacifiCorp's two balancing authority areas are shown in Table F.9 below.

Table F.9 - Reserve Requirements (Average MW)

Year	East Requirement			West Requirement		
	Spin (10-minute)	Non-spin (10-minute)	Regulation (30-minute)	Spin (10-minute)	Non-spin (10-minute)	Regulation (30-minute)
2023	342	342	850	272	272	261
2024	343	343	1,113	278	278	274
2025	347	347	1,268	283	283	291
2026	344	344	1,539	285	285	381
2027	347	347	1,534	289	289	422
2028	353	353	1,548	294	294	424
2029	355	355	1,640	296	296	425
2030	356	356	1,633	296	296	425
2031	358	358	1,602	298	298	424
2032	357	357	1,598	298	298	422
2033	359	359	1,597	299	299	424
2034	360	360	1,634	300	300	495
2035	361	361	1,837	301	301	606
2036	362	362	2,216	301	301	757
2037	365	365	1,801	303	303	910
2038	367	367	1,789	303	303	921
2039	368	368	1,963	305	305	947
2040	369	369	2,047	306	306	950
2041	382	382	2,048	310	310	954
2042	386	386	2,074	312	312	968

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.[21] 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.

[21] 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.

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

Year	East Supply (10-Minute)	West Supply (10-Minute)	East Supply (30-Minute)	West Supply (30-Minute)
2023	1,301	922	1,823	895
2024	1,291	934	2,221	1,036
2025	1,247	949	2,606	992
2026	1,245	911	2,734	1,819
2027	1,231	1,104	2,714	1,970
2028	1,333	824	3,022	1,837
2029	1,274	858	3,233	1,925
2030	1,277	855	3,335	1,912
2031	1,282	858	3,304	1,887
2032	1,202	2,314	3,089	2,186
2033	1,237	2,295	3,202	2,206
2034	3,256	2,199	3,264	2,117
2035	3,357	2,138	3,529	2,273
2036	3,463	2,164	3,974	2,510
2037	3,544	2,171	3,748	2,495
2038	3,517	2,154	3,842	2,648
2039	3,672	2,190	3,965	2,695
2040	3,725	2,205	4,000	2,693
2041	3,742	2,157	4,078	2,697
2042	3,756	2,015	4,106	2,541

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, and accounts for some of the increase in supply after 2030. In addition, PacifiCorp currently can transfer a portion of the operating reserves held in either of its balancing authority areas to help meet the requirements of its other balancing authority area, based on the reserve need and relative economics of the available supply.

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

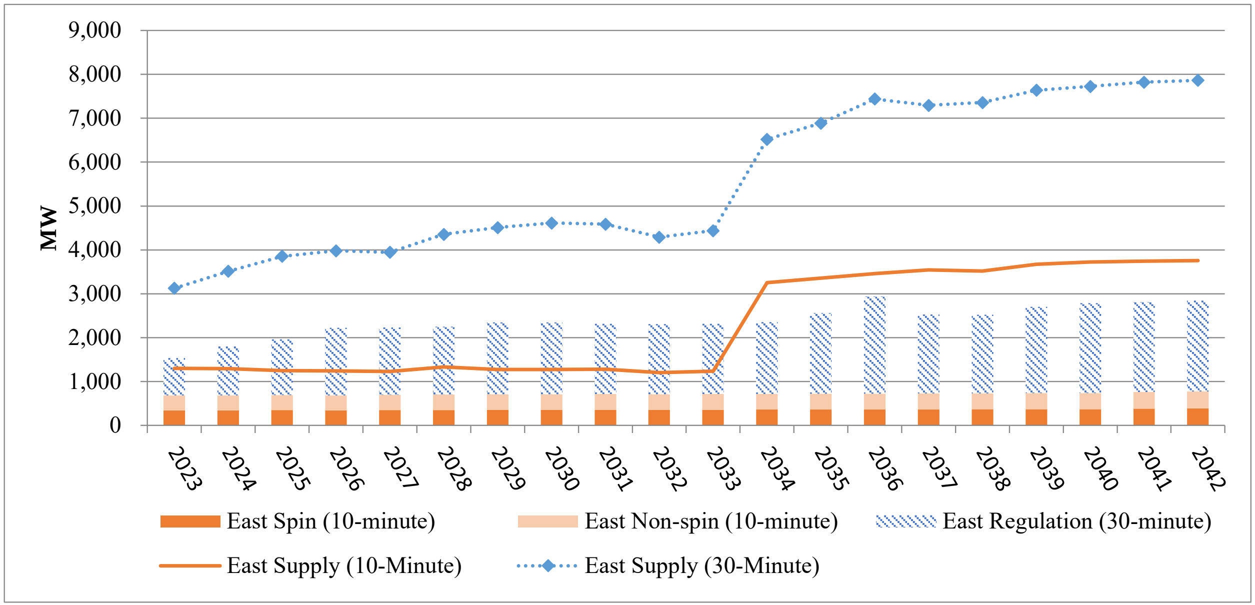
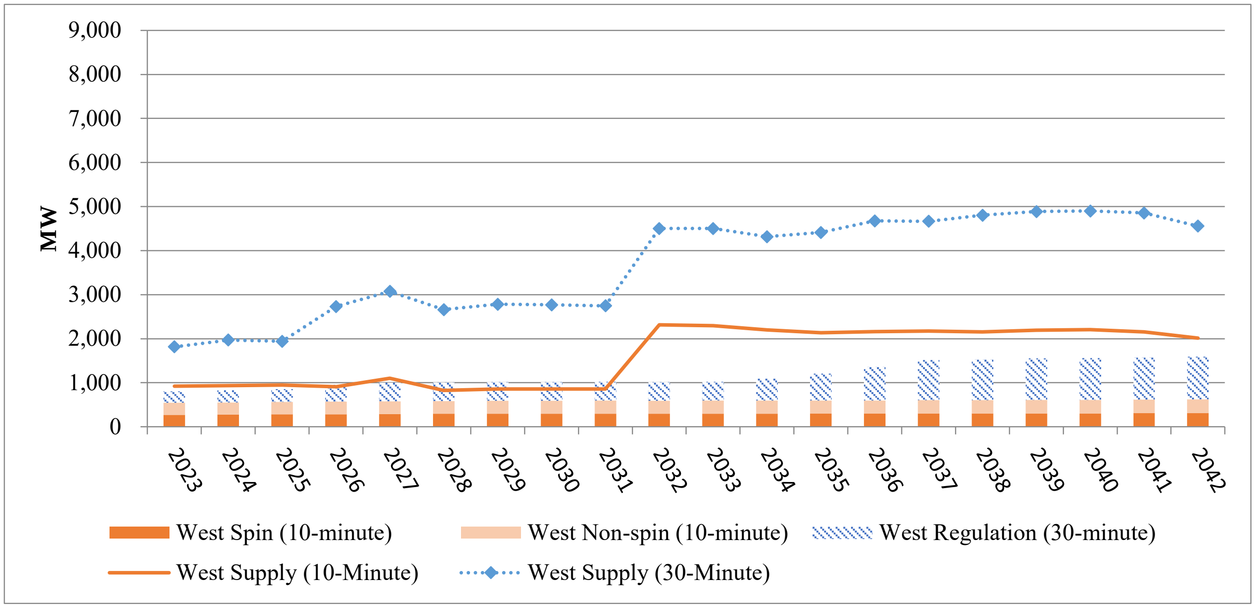


Figure F.13 - Comparison of Reserve Requirements and Resources, West Balancing Authority Area (MW)



Flexible Resource Supply Planning

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

PacifiCorp and the California Independent System Operator Corporation implemented the energy imbalance market (EIM) on November 1, 2014, and participation by other utilities has expanded significantly with more participants scheduled for entry through 2023. 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. For the first time in the 2023 IRP, electric vehicle load control is one of the demand response options available for selection. While electric vehicle load control was not one of the programs selected to the preferred portfolio, new demand response programs included in the preferred portfolio provide 275 average megawatts of operating reserves by 2030, and 860 average megawatts of operating reserves by 2042. While operating reserves 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.

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	2019	2020	2021	2022	4-year Average	2019	2020	2021	2022	Gals/ MWH	GPM/ MW
Chehalis		Air	63	66	71	47	62	2,431,536	2,407,519	2,248,237	2,172,465	9	0.1
Currant Creek	Yes	Air	101	95	113	85	98	2,917,279	2,335,426	2,746,290	2,805,979	12	0.2
Dave Johnston		Water	8,485	7,856	6,571	5,901	7,203	4,686,381	4,325,604	3,601,242	3,581,919	580	9.7
Gadsby		Water	281	409	339	454	371	134,182	133,410	83,008	118,821	1,029	17.2
Hunter	Yes	Water	15,808	15,103	16,326	13,426	15,166	8,681,784	7,988,203	9,248,963	7,381,184	594	9.9
Huntington	Yes	Water	9,028	7,929	12,019	11,717	10,173	4,897,541	4,515,305	6,263,658	5,673,115	621	10.4
Jim Bridger	Yes	Water	19,893	18,184	19,103	19,076	19,064	11,254,989	10,458,575	10,342,840	10,662,019	582	9.7
Lake Side		Water	3,894	4,075	4,421	4,591	4,245	5,063,816	5,560,112	6,389,355	6,578,673	235	3.9
Naughton	Yes	Water	10,195	7,622	7,236	6,929	7,996	2,840,374	2,659,033	2,596,446	2,456,201	988	16.5
Wyodak	Yes	Air	292	336	333	324	321	1,852,094	1,732,784	1,717,528	1,779,843	59	1.0
TOTAL			**68,040**	**61,675**	**66,531**	**62,551**	**64,699**	**44,759,976**	**42,115,971**	**45,237,567**	**43,210,219**	**481**	**8.0**

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

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

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

UTAH PLANTS							
Plant Name	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Currant Creek	124	116	110	101	95	113	85
Gadsby	262	100	205	281	409	339	454
Hunter	14,225	15,383	14,751	15,808	15,103	16,326	13,426
Huntington	9,189	9,653	9,804	9,028	7,929	12,019	11,717
Lake Side	3,619	2,698	3,648	3,894	4,075	4,421	4,591
TOTAL	**27,419**	**27,950**	**28,518**	**29,112**	**27,611**	**33,217**	**30,274**

Percent of total water consumption = 45.4%

WYOMING PLANTS							
Plant Name	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Dave Johnston	8,864	8,231	8,325	8,485	7,856	6,571	5,901
Jim Bridger	18,000	19,047	20,067	19,893	18,184	19,103	19,076
Naughton	6,896	6,927	9,916	10,195	7,622	7,236	6,929
Wyodak	329	332	319	292	336	333	324
TOTAL	**34,090**	**34,537**	**38,627**	**38,865**	**33,998**	**33,243**	**32,230**

Percent of total water consumption = 54.6%

Table G.3 – Plant Water Consumption by Fuel Type (acre-feet)

COAL FIRED PLANTS							
Plant Name	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Dave Johnston	8,864	8,231	8,325	8,485	7,856	6,571	5,901
Hunter	14,225	15,383	14,751	15,808	15,103	16,326	13,426
Huntington	9,189	9,653	9,804	9,028	10,423	10,643	10,240
Jim Bridger	18,000	19,047	20,067	19,893	18,184	19,103	19,076
Naughton	6,896	6,927	9,916	10,195	7,622	7,236	6,929
Wyodak	329	332	319	292	336	333	324
TOTAL	**57,504**	**59,573**	**63,182**	**63,701**	**59,524**	**60,212**	**55,896**

Percent of total water consumption = 93.3%

NATURAL GAS FIRED PLANTS							
Plant Name	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Currant Creek	124	116	110	101	95	113	85
Chehalis	48	54	33	63	66	71	47
Gadsby	262	100	205	281	409	339	454
Lake Side	3,619	2,698	3,648	3,894	4,075	4,421	4,591
TOTAL	**4,053**	**2,968**	**3,996**	**4,339**	**4,644**	**4,943**	**5,178**

Percent of total water consumption = 6.7%

Table G.4 – Plant Water Consumption for Plants Located in the Upper Colorado River Basin (acre-feet)

Plant Name	2016	2017	2018	2019	2020	2021	2022
Hunter	14,225	15,383	14,751	15,808	15,103	16,326	13,426
Huntington	9,189	9,653	9,804	9,028	7,929	12,019	11,717
Naughton	6,896	6,927	9,916	10,195	7,622	7,236	6,929
Jim Bridger	18,000	19,047	20,067	19,893	18,184	19,103	19,076
TOTAL	**48,311**	**51,010**	**54,537**	**54,924**	**48,839**	**54,684**	**51,148**

Percent of total water consumption = 80.8%

APPENDIX H – STOCHASTIC PARAMETERS

Introduction

For the 2023 IRP, PacifiCorp updated and re-estimated the stochastic parameters provided in the 2021 IRP for use in the development of the 2023 IRP preferred portfolio.

Plexos, as used by PacifiCorp, develops portfolio cost scenarios via computational finance in concert with production simulation. The model stochastically shocks the case-specific underlying electricity price forecast as well as the corresponding case-specific key drivers (e.g., natural gas, loads, and hydro) and dispatches accordingly. Using exogenously calculated parameters (i.e., volatilities, mean reversions, and correlations), Plexos develops scenarios that bracket the uncertainty surrounding a driver; statistical sampling techniques are then employed to limit the number of representative scenarios to 50. The stochastic model used in Plexos is a two-factor (short- and long-run) mean reverting model.

PacifiCorp used short-run stochastic parameters for this Integrated Resource Plan (IRP); long-run parameters were set to zero since Plexos cannot re-optimize its capacity expansion plan. This inability to re-optimize or add capacity can create a problem when dispatching to meet extreme load and/or fuel price excursions, as often seen in long-term stochastic modeling. Such extreme out-year price and load excursions can influence portfolio costs disproportionately while not reflecting plausible outcome. Thus, since long-term volatility is the year-on-year growth rate, only the expected yearly price and/or load growth is simulated over the forecast horizon[1].

Key drivers that significantly affect the determination of prices tend to fall into two categories: loads and fuels. Targeting only key variables from each category simplifies the analysis while effectively capturing sensitivities on a larger number of individual variables. For instance, load uncertainty can encompass the sensitivities of weather, transmission availability, unit outages, and evolving end-uses. Depending on the region, fuel price uncertainty (especially natural gas) can encompass the sensitivities of weather, load growth, emissions, and hydro availability. The following sections summarize the development of stochastic process parameters and describe how these uncertain variables evolve over time.

Overview

Long-term planning demands specification of how important variables behave over time. For the case of PacifiCorp's long-term planning, important variables include natural gas and electricity prices, regional loads, and regional hydro generation. Modeling these variables involves not only a description of their expected value over time as with a traditional forecast, but also a description of the spread of possible future values. The following sections summarize the development of stochastic process parameters to describe how these uncertain variables evolve over time[2].

[1] Mean reversion is assumed to be zero in the long run.

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

Volatility

The standard deviation[3](σ) is a measure of how widely values are dispersed from the average value:

$$\sigma = \sqrt{\frac{\sum_{i=1}^{n}(x_i - \mu)^2}{(n-1)}}$$

where μ is the average value of the observations {x1, x2,…,xn}, and n is the number of observations.

Volatility (σ_T) incorporates a time component so a variable with constant volatility has a larger spread of possible outcomes two years in the future than one year in the future:

$$\sigma_T = \sigma\sqrt{T}$$

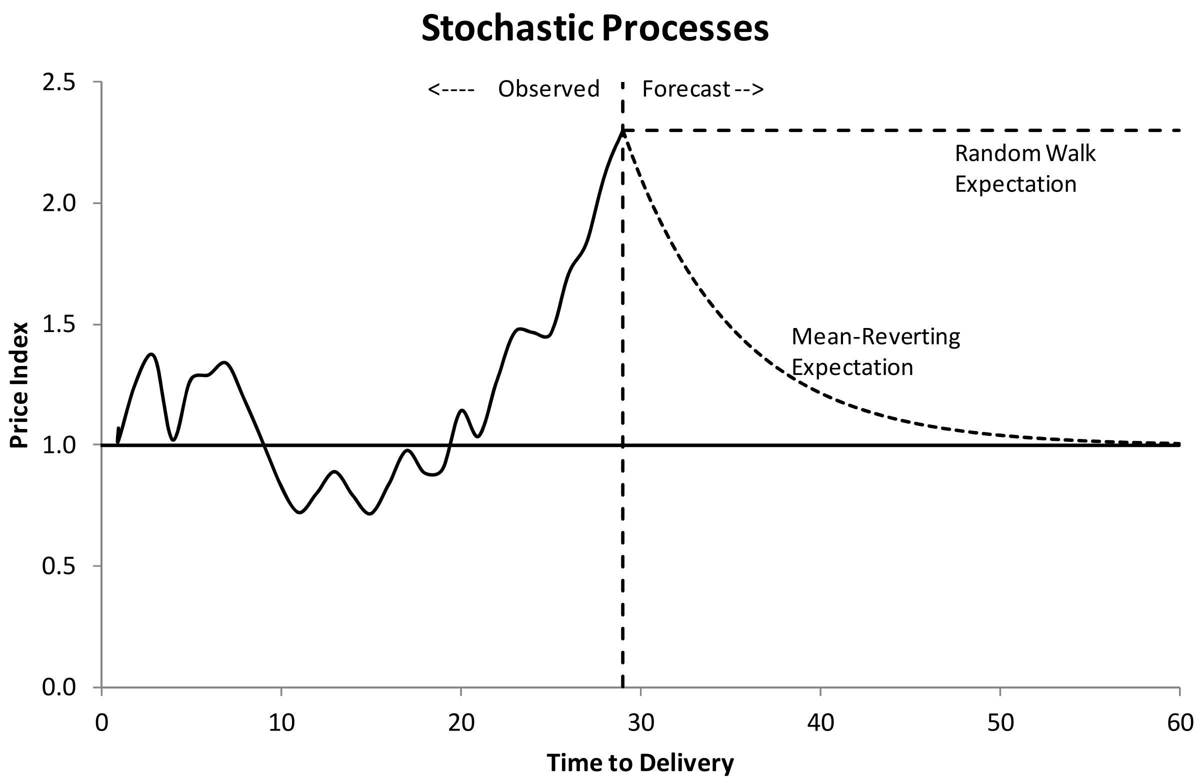
Volatilities are typically quoted on an annual basis but can be specified for any desired time (T). Suppose the annual volatility of load is two percent. This implies that the standard deviation of the range of possible loads a year from now is two percent, while the standard deviation four years from now is four percent.

Mean Reversion

If volatility was constant over the forecast period, then the standard deviation would increase linearly with the square root of time. This is described as a "Random Walk" process and often provides a reasonable assumption for long-term uncertainty. However, for energy commodities as well as many other variables in the short-term, this is not typically the case. Excepting seasonal effects, the standard deviation increases less quickly with longer forecast time. This is called a mean reverting process - variable outcomes tend to revert back towards a long-term mean after experiencing a shock.

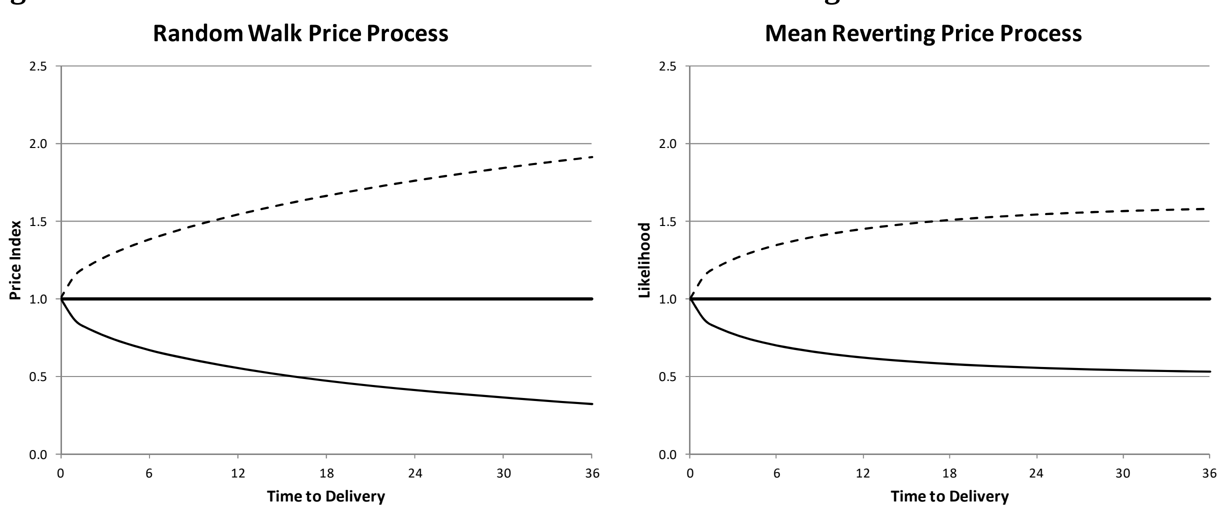
[3] "Standard Deviation" and "Variance" are standard statistical terms describing the spread of possible outcomes. The Variance equals the Standard Deviation squared.

Figure H.1 – Stochastic Processes



For a random walk process, the distribution of possible future outcomes continues to increase indefinitely, while for a mean reverting process, the distribution of possible outcomes reaches a steady-state. Actual observed outcomes will continue to vary within the distribution, but the distribution across all possible outcomes does not increase:

Figure H.2 – Random Walk Price Process and Mean Reverting Process



The volatility and mean reversion rate parameters combine to provide a compact description of the distribution of possible variable outcomes over time. The volatility describes the size of a typical shock or deviation for a particular variable and the mean reversion rate describes how quickly the variable moves back toward the long-run mean after experiencing a shock.

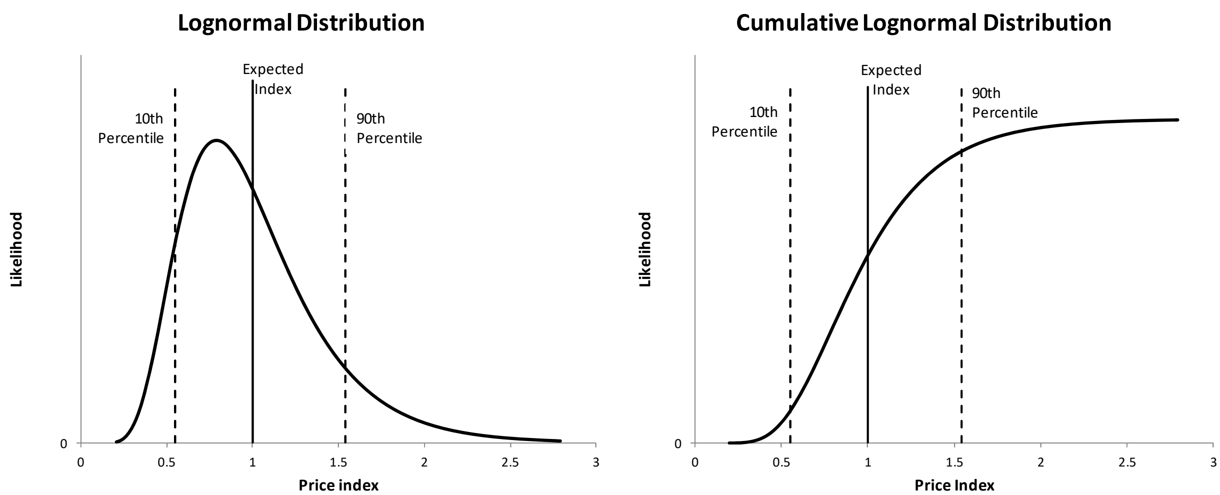
Estimating Short-term Process Parameters

Short-term uncertainty can best be described as a mean reverting process. The factors that drive uncertainty in the short-term are generally short-lived, decaying back to long-run average levels. Short-term uncertainty is mainly driven by weather (temperature, windiness, rainfall) but can also be driven by short-term economic factors, congestion, outages, etc. The process for estimating short-term uncertainty parameters is similar for most variables of interest. However, each of PacifiCorp's variables have characteristics that make their processes slightly different. The process for estimating short-term uncertainty parameters is described in detail below for the most straightforward variable – natural gas prices. Each of the other variables is then discussed in terms of how they differ from the standard natural gas price parameter estimation process.

Stochastic Process Description

The first step in developing process parameter estimates for any uncertain variable is to determine the form of the distribution and time step for uncertainty. In the case of natural gas, and for prices in general, the lognormal distribution is a good representation of possible future outcomes. A lognormal distribution is a continuous probability distribution of a random variable whose logarithm is normally distributed[4]. The lognormal distribution is often used to describe prices because it is bounded on the bottom by zero and has a long, asymmetric "tail" reflecting the possibility that prices could be significantly higher than the average:

Figure H.3 – Lognormal Distribution and Cumulative Lognormal Distribution



The time step for calculating uncertainty parameters depends on how quickly a variable can experience a significant change. Natural gas prices can change substantially from day-to-day and are reported on a daily basis, so the time step for analysis will be one day.

[4] A normal distribution is the most common continuous distribution represented by a bell-shaped curve that is symmetrical about the mean, or average, value.

All short-term parameters were calculated on a seasonal basis to reflect the different dynamics present during different seasons of the year. For instance, the volatility of gas prices is higher in the winter and lower in the spring and summer. Seasons were defined as follows:

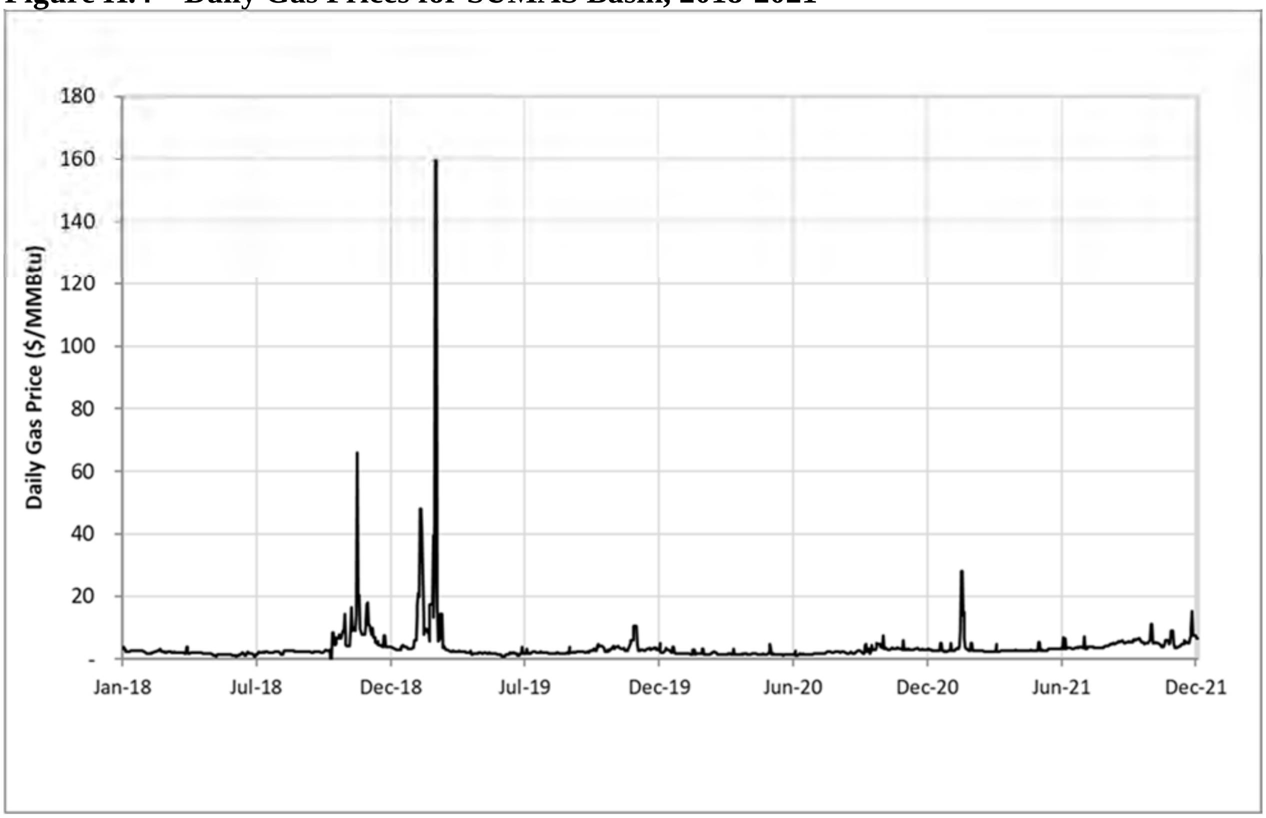
Table H.1 - Seasonal Definitions

Winter	December, January, and February
Spring	March, April, and May
Summer	June, July, and August
Fall	September, October, and November

Data Development

Basic Data Set:
The natural gas price data was organized into a consistent dataset with one natural gas price for each gas delivery point reported for each delivery day. The data was checked to make sure that there were no missing or duplicate dates. If no price is reported for a particular date, the date is included but left blank to maintain a consistent 24-hour time step between all observed prices. Four years of daily data from 2018 to 2021 was used for this short-term parameter analysis. The following chart shows the resulting data set for the Sumas gas basin:

Figure H.4 – Daily Gas Prices for SUMAS Basin, 2018-2021



Development of Price Index:
Uncertainty parameters are estimated by looking at the movement, or deviation, in prices from one day to the next. However, some of this movement is due to expected factors, not uncertainty. For

instance, gas prices are expected to be higher during winter or as we move toward winter. This expectation is already included in the gas price forecast and should not be considered a shock, or random event. To capture only the random or uncertain portion of price movements, a price index is developed that takes into account the expected portion of price movements. Three categories of price expectations are calculated:

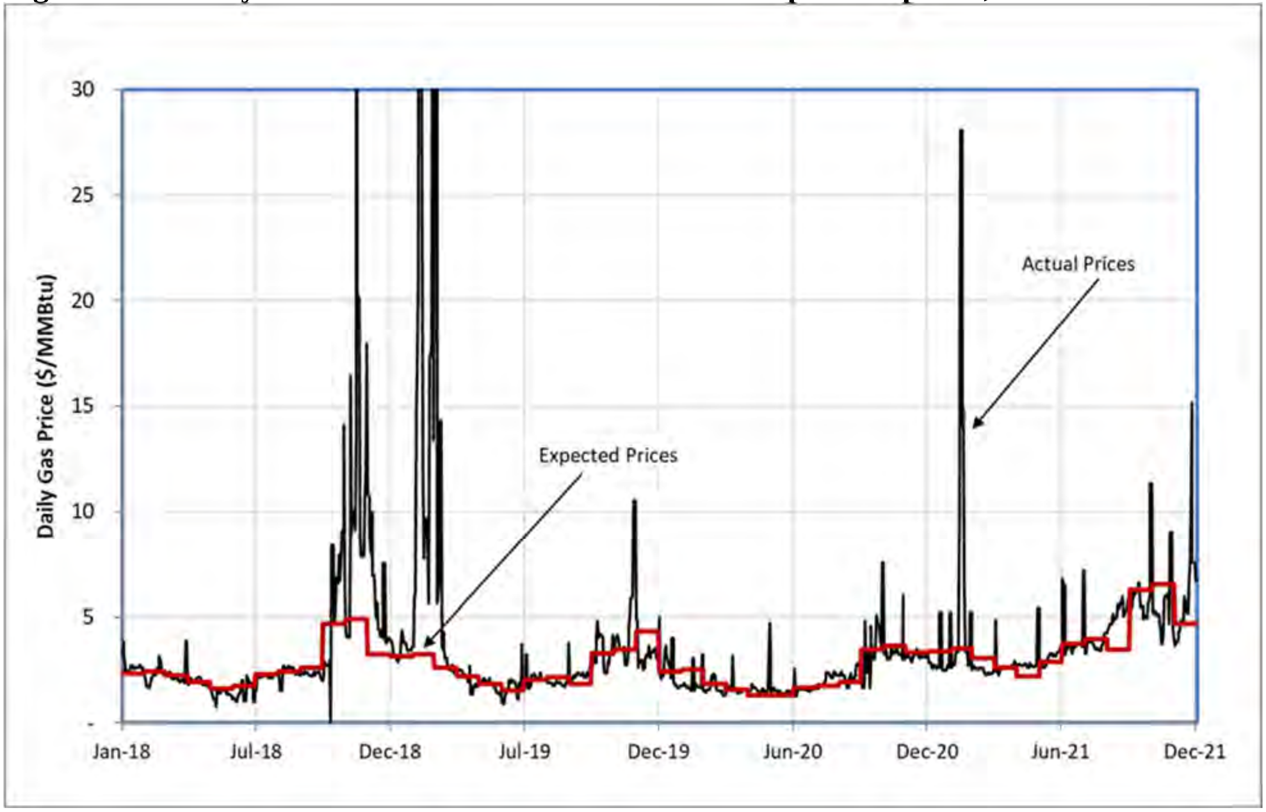
> Seasonal Median: The level of gas prices may be different from one year to the next. While this can be attributed to random movements or shocks in the gas markets, it is not a short-term event and should not be included in the short-term uncertainty process. To account for this possible difference in the level of gas prices, the median gas price for each season and year is calculated. For example, Sumas prices in the winter of 2018 average $2.68/MMBtu.
>
> Monthly Median: Within a season, there are different expected prices by month. For instance, within the fall season, November gas prices are expected to be much higher than September and October prices as winter is just around the corner. A monthly factor representing the ratio of monthly prices to the seasonal median price is calculated. For example, February prices in Sumas are 91 percent of the winter median price.
>
> Weekly Shape: Many variables exhibit a distinct shape across the week. For instance, loads and electricity prices are higher during the middle of the week and lower on the weekends. The expected shape of gas prices across the week was calculated and found to be insignificant (expected variation by weekday did not exceed three percent of the weekly average).

These three components – seasonal median, monthly shape, and weekly shape – combine to form an expected price for each day. For example, the expected price of gas in Sumas on February 1, 2018 was $2.21/MMBtu, the product of the seasonal median and the monthly shape factor

$$Expected\ Gas\ Price\ = Seasonal\ Median. Price * Monthly\ Shape\ within\ the\ Season$$

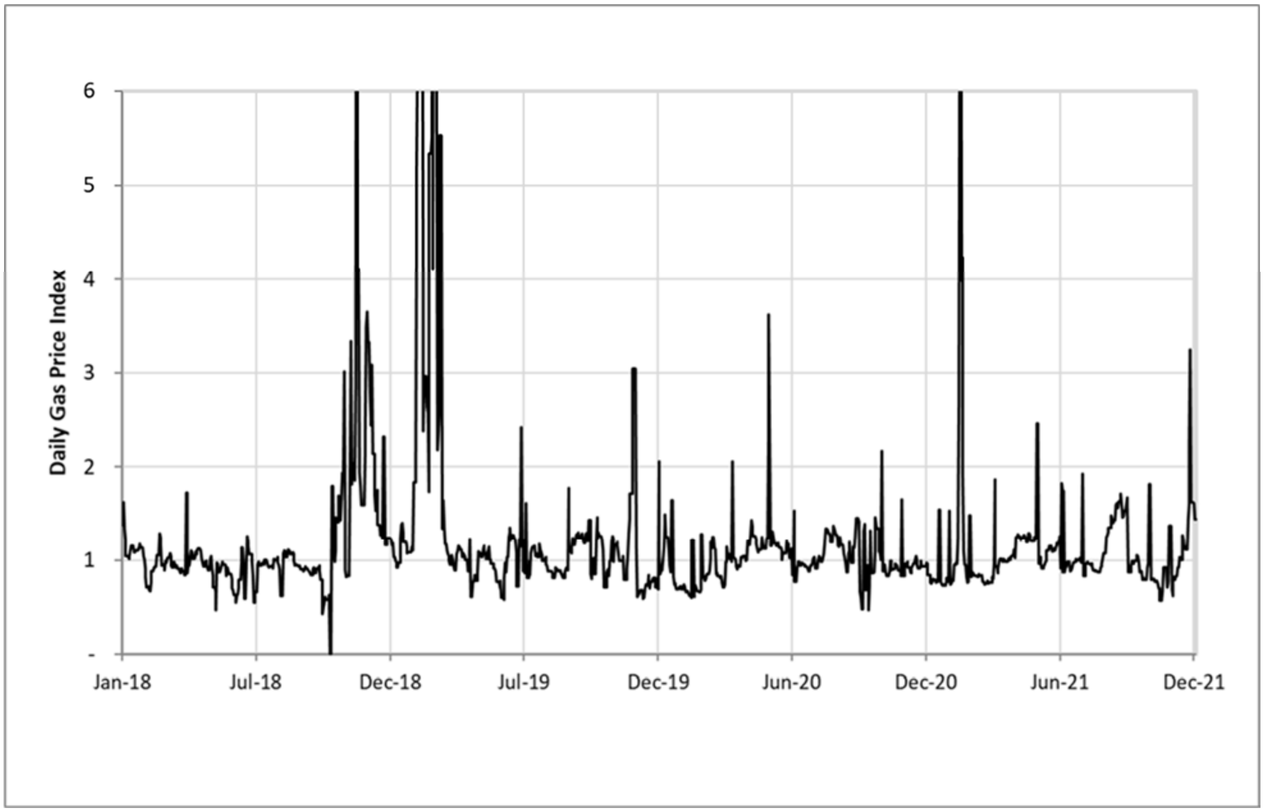
The following chart shows the comparison of the actual Sumas prices with the "expected" prices:

Figure H.5 – Daily Gas Prices for SUMAS Basin with "expected" prices, 2018-2021



Dividing the actual gas prices by the expected prices forms a price index with a median of one. This index, illustrated by the chart below, captures only the random component of price movements—the portion not explained by expected seasonal, monthly, and weekly shape.

Figure H.6 – Gas Price Index for SUMAS Basin, 2018-2021



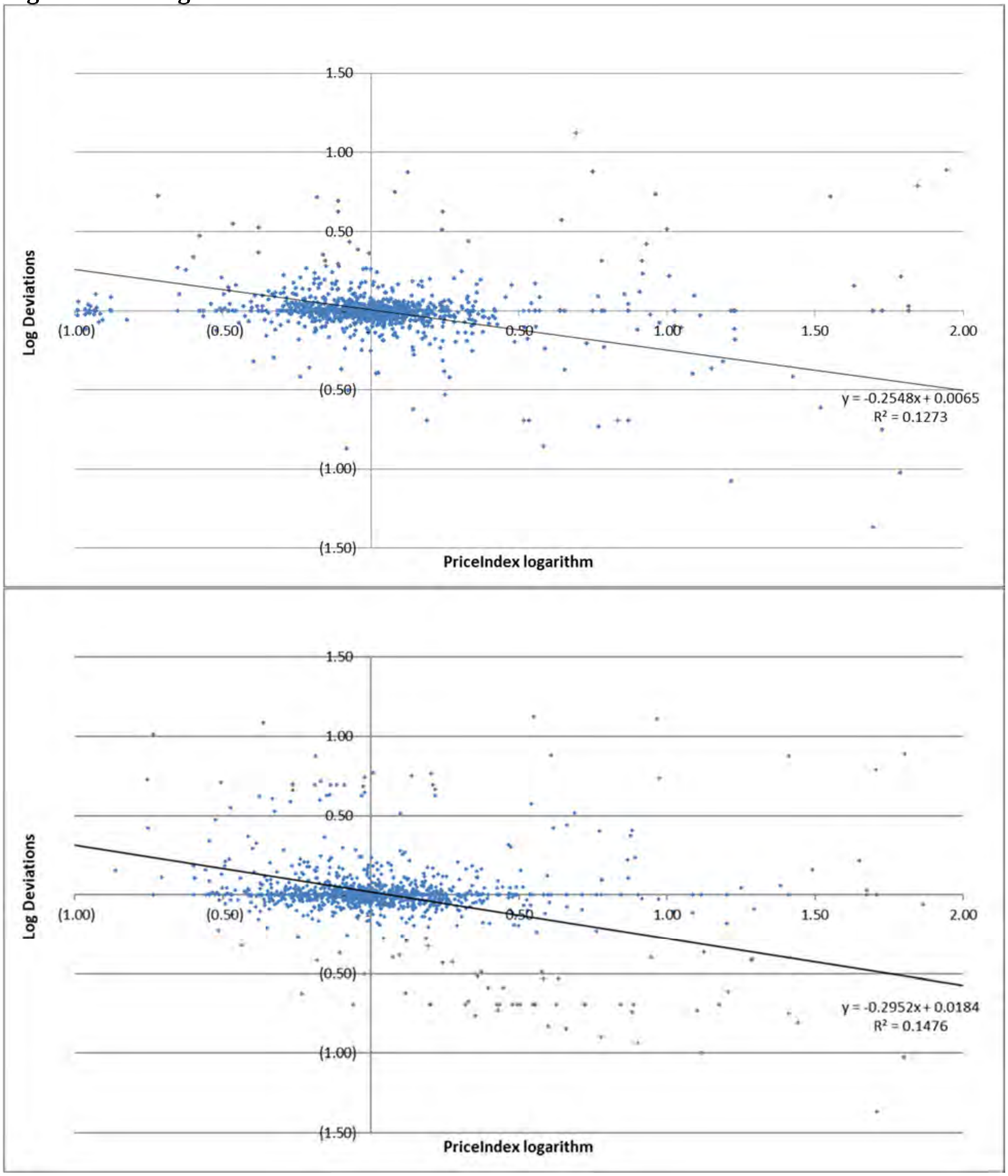
Parameter Estimation – Autoregressive Model

Uncertainty parameters are calculated for each variable by regressing the movement of each region's price index compared to the previous day's index.

Step 1 - Calculate Log Deviation of Price Index
Since gas prices are lognormally distributed, the regression analysis is performed on the natural log of prices and their log deviations. The log deviations are simply the differences between the natural log of one day's price index and the natural log of the previous day's price index.

Step 2 - Perform Regression
The log deviations of price index are regressed against the previous day's logarithm of price index for each season as well as for the entire data set. The following chart shows the log of the price index versus the log deviations for Sumas gas for all seasons and the resulting regression equation:

Figure H.7 – Regression for SUMAS Gas Basin



Step 3 - Interpret the Results

The INTERCEPT of the regression represents the log of the long-run mean. So in this case, the intercept is approximately zero, implying that the long-run mean is equal to one. This is consistent with the way in which the price index is formulated.

The *SLOPE* of the regression is related to the auto correlation and mean reversion rate:

$$auto\ correlation = \emptyset = 1 + slope$$
$$Mean\ Reversion\ Rate\ \ \alpha = -\ln(\emptyset)$$

The autocorrelation measures how much of the price shock from the previous time period remains in the next time period. For instance, if the autocorrelation is 0.4 and gas prices yesterday experienced a 10 percent jump over the norm, today's expected price would be 4 percent higher than normal. In addition, today's gas price will experience a shock today that may result in prices higher or lower than this expectation. The mean reversion rate expresses the same thing in a different manner. The higher the mean reversion rate, the faster prices revert to the long-run mean.

The last component of the regression analysis is the *STANDARD ERROR* or *STEYX*. This measures the portion of the price movements not explained by mean reversion and is the estimate of the variable's volatility.

Both the mean reversion rate and volatility calculated with this process are daily parameters and can be applied directly to daily movements in gas prices.

Step 4 - Results
The natural gas price parameters derived through this process are reported in the table below.

Table H.2 - Uncertainty Parameters for Natural Gas

	Winter	Spring	Summer	Fall
KERN OPAL				
Daily Volatility	27.16%	13.44%	13.47%	15.28%
Daily Mean Reversion Rate	0.129	0.304	0.525	0.244
SUMAS				
Daily Volatility	23.66%	22.44%	14.77%	74.31%
Daily Mean Reversion Rate	0.074	0.155	0.405	0.570

Electricity Price Process

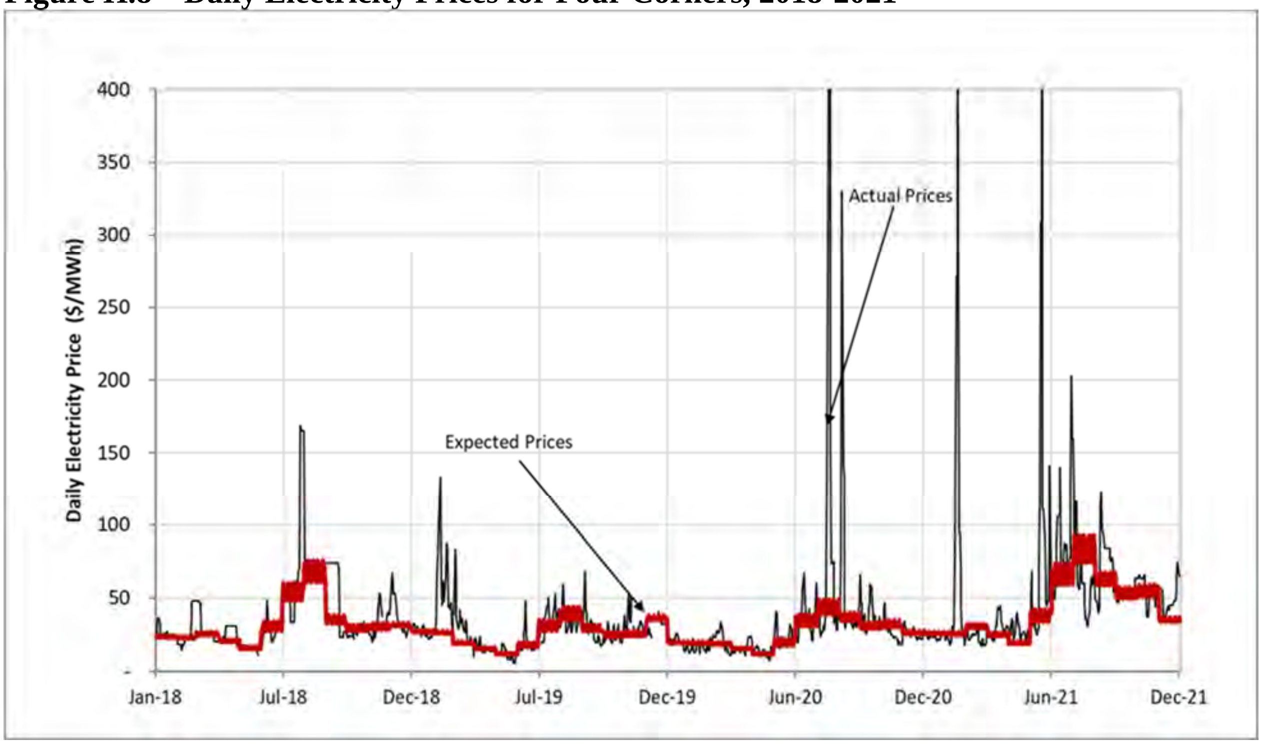
For the most part, electricity prices behave very similarly to natural gas prices. The lognormal distribution is generally a good assumption for electricity. While electricity prices do occasionally go below zero, this is not common enough to be worth using the Normal distribution assumption, and the distribution of electricity prices is often skewed upwards. In fact, even the lognormal assumption is sometimes inadequate for capturing the tail of the electricity price distribution. Like gas prices, electricity price can experience substantial change from one day to the next, so a daily time step should be used.

Basic Data Set:
The electricity price data was organized into a consistent dataset with one price for each region reported for each delivery day, like gas prices. The data covers the 2018 through 2021 period. However, electricity prices are reported for "High Load Level" periods (16 hours for six days a week) and "Low Load Level" periods (eight hours for six days a week and 24 hours on Sunday & NERC holidays). To have a consistent price definition, a composite price, calculated based on 16

hours of peak and eight hours of off-peak prices, is used for Monday through Saturday. The Low Load Level price was used for Sundays since that already reflects the 24-hour price. Missing and duplicate data is handled in a fashion like gas prices. Illiquid delivery point prices are filled using liquid hub prices as reference. Mid-C is the most liquid market in PACW, so missing prices for COB are filled using the latest available spread between COB and Mid-C markets. Similarly, Four Corner prices are filled using Palo Verde prices.

Development of Price Index:
As with gas prices, an electricity price index was developed which accounts for the expected components of price movements. The "expected" electricity price incorporates all three possible adjustments: seasonal median, monthly shape, and weekly shape. For instance, the expected price for January 2, 2018, in the Four Corners region was $24.22/megawatt hours (MWh). This price incorporates the 2018 winter median price of $26.00/MWh times the monthly shape factor for January of 90 percent and the weekday index for Saturday of 98 percent. The following chart shows the Four Corners actual and expected electricity prices over the analysis time period.

Figure H.8 – Daily Electricity Prices for Four Corners, 2018-2021



Electricity Price Uncertainty Parameters
Uncertainty parameters are calculated for each electric region, similar to the process for gas prices. The electricity price parameters derived through this process are reported in the table below.

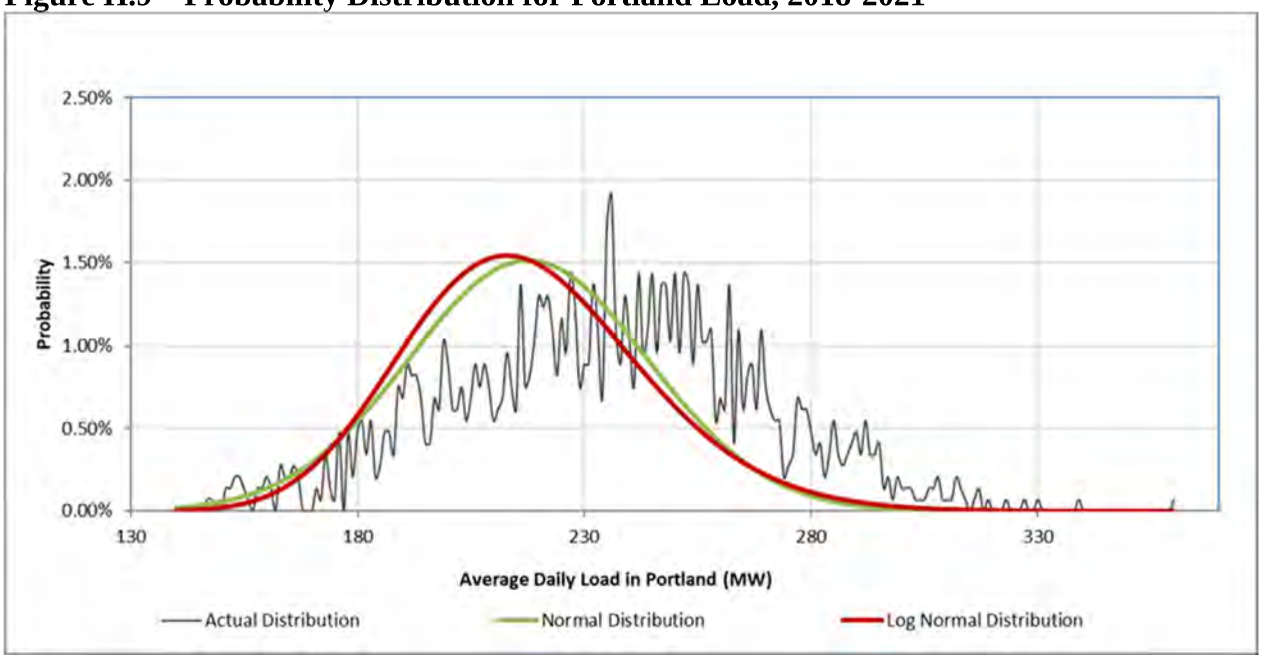
Table H.3 - Uncertainty Parameters for Electricity Regions

	Winter	Spring	Summer	Fall
Four Corners				
Daily Volatility	19.42%	19.26%	31.11%	21.46%
Daily Mean Reversion Rate	0.103	0.216	0.213	0.238
CA-OR Border				
Daily Volatility	19.10%	23.80%	94.62%	18.88%
Daily Mean Reversion Rate	0.101	0.213	1.014	0.297
Mid-Columbia				
Daily Volatility	22.31%	56.40%	39.16%	18.97%
Daily Mean Reversion Rate	0.101	0.477	0.300	0.294
Palo Verde				
Daily Volatility	17.44%	16.45%	28.82%	20.58%
Daily Mean Reversion Rate	0.102	0.199	0.149	0.230

Regional Load Process

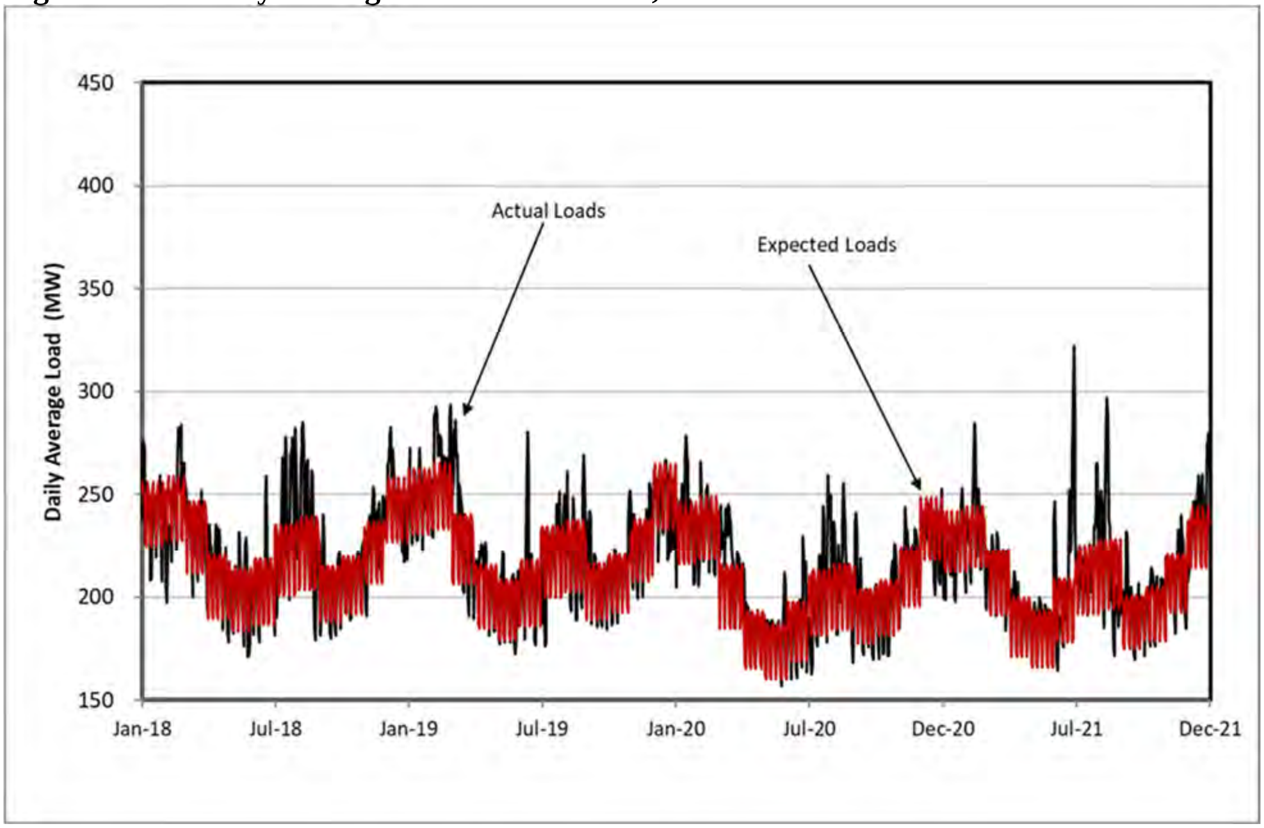
There are only two significant differences between the uncertainty analysis for regional loads and natural gas prices. The distribution of daily loads is somewhat better represented by a normal distribution rather than a lognormal distribution, and similar to electricity prices, loads have a significant expected shape across the week. The chart below shows the distribution of historical load outcomes for the Portland area as well as normal and lognormal distribution functions representing load possibilities. Both distributions do a reasonable job of representing the spread of possible load outcomes, but the tail of the lognormal distribution implies the possibility of higher loads than is supported by the historical data.

Figure H.9 – Probability Distribution for Portland Load, 2018-2021



Development of Load Index:
As with electricity prices, a load index was developed which accounts for the expected components of load movements, incorporating all three possible adjustments. For instance, the expected load for January 2, 2018, in Portland was 275 megawatts (MW). This load incorporates the 2018 winter average load of 245 MW times the monthly shape factor for January of 99 percent and the weekday index for Saturday also of 93 percent. The following chart shows the Portland actual and expected loads over the analysis period.

Figure H.10 – Daily Average Load for Portland, 2018-2021



Load Uncertainty Parameters:
Uncertainty parameters are calculated for each load region, like the process for gas and electricity prices. Since loads are modeled as normally, rather than log-normally distributed, deviations are simply calculated as the difference between the load index and the previous day's index.

The uncertainty parameters for regional loads derived through this process are reported in the table below.

Table H.4 - Uncertainty Parameters for Load Regions

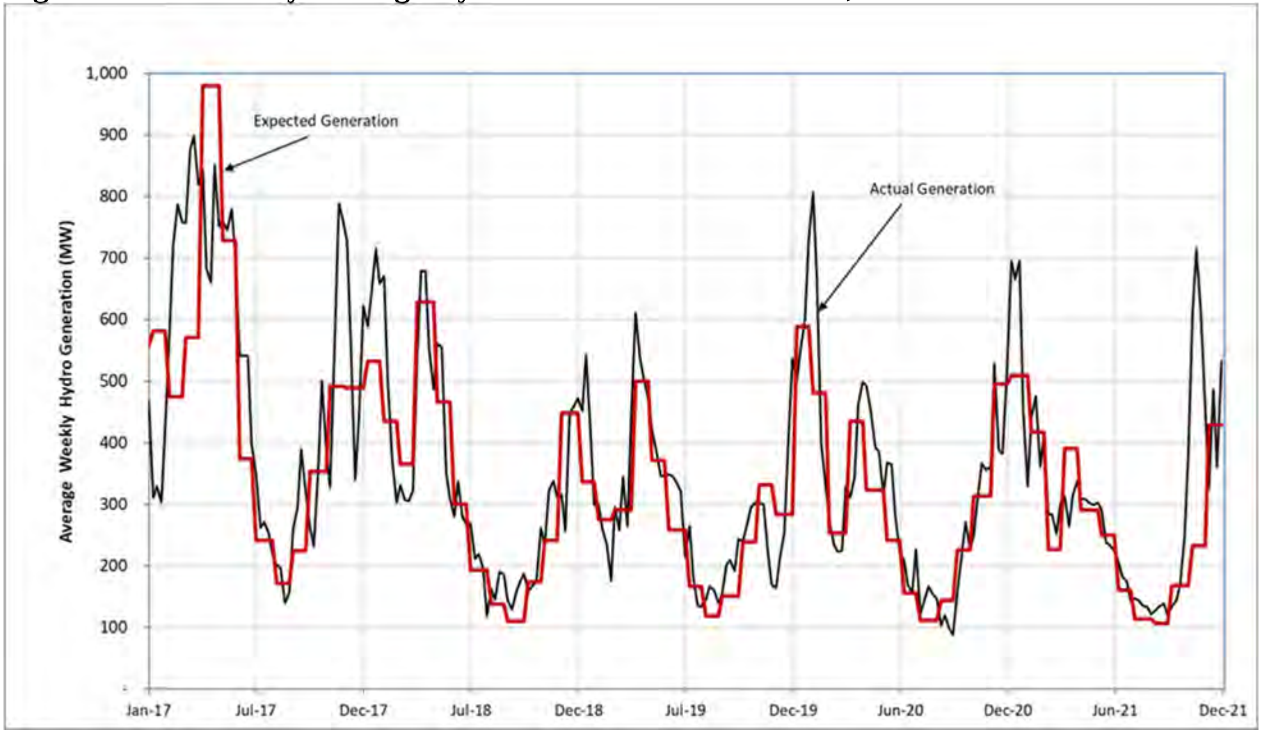
	Winter	Spring	Summer	Fall
California				
Daily Volatility	4.58%	4.15%	4.19%	4.64%
Daily Mean Reversion Rate	0.258	0.153	0.185	0.222
Idaho				
Daily Volatility	3.81%	6.44%	6.11%	4.68%
Daily Mean Reversion Rate	0.263	0.146	0.143	0.128
Portland				
Daily Volatility	4.06%	3.54%	5.95%	3.59%
Daily Mean Reversion Rate	0.252	0.229	0.183	0.365
Oregon Other				
Daily Volatility	4.36%	3.63%	4.55%	4.20%
Daily Mean Reversion Rate	0.261	0.242	0.168	0.253
Utah				
Daily Volatility	2.41%	3.47%	5.41%	3.49%
Daily Mean Reversion Rate	0.380	0.332	0.265	0.234
Washington				
Daily Volatility	5.03%	4.20%	5.37%	4.42%
Daily Mean Reversion Rate	0.171	0.164	0.173	0.213
Wyoming				
Daily Volatility	2.08%	2.08%	2.12%	2.01%
Daily Mean Reversion Rate	0.279	0.109	0.190	0.224

Hydro Generation Process

There are two differences between the uncertainty analysis for hydro generation and natural gas prices. Hydro generation varies on a slower time frame than other variables analyzed. As such, median hydro generation is calculated and analyzed on a weekly, rather than daily, basis. Generation is calculated as the median hourly generation across the 168 hours in a week. The hydro analysis covers the 2017 through 2021 period.

Development of Hydro Index:
A hydro generation index was developed which accounts for the expected components of hydro movements, incorporating seasonal and monthly adjustments. For instance, the expected hydro generation for the week of January 1, 2017, through January 7, 2017 in the Western Region was 467 MW. This generation incorporates the 2017 winter median generation of 515 MW times the monthly shape factor for January of 113 percent. The following chart shows the western hydro actual and expected generation over the analysis period.

Figure H.11 – Weekly Average Hydro Generation in the West, 2017-2021



Hydro Generation Uncertainty Parameters:

Uncertainty parameters are calculated for each hydro region, similar to the process for gas and electricity prices. The uncertainty parameters for hydro generation derived through this process are reported in the table below.

Table H.5 - Uncertainty Parameters for Hydro Generation

	Winter	Spring	Summer	Fall
Weekly Volatility	25.68%	20.11%	19.48%	27.59%
Weekly Mean Reversion Rate	0.68	0.77	1.80	0.36

Short-term Correlation Estimation

Correlation is a measure of how much the random component of variables tend to move together. After the uncertainty analysis has been performed, the process for estimating correlations is relatively straight-forward.

Step 1 - Calculate Residual Errors

Calculate the residual errors of the regression analysis for all the variables. The residual error represents the random portion of the deviation not explained by mean reversion. It is calculated for each period as the difference between the actual value and the value predicted by the linear regression equation:

$$Error = Actual\ Deviation - (Slope * Previous\ Deviation + Intercept)$$

All of the residual errors are compiled by delivery date.

Step 2 - Calculate Correlations
Correlate the residual errors of each pair of variables:

$$Correlation(X,Y) = \frac{\sum_i^n[(x_i - x_{avg.}) * (y_i - y_{avg.})]}{\sqrt{\sum_i^n (x_i - x_{avg.})^2 * \sum_i^n (y_i - y_{avg.})^2}}$$

There are a few things to note about the correlation calculations. First, correlation data must always be organized so that the same period is being compared for both variables. For instance, weekly hydro deviations cannot be compared to daily gas price deviations. Thus, a daily regression analysis was performed for the hydro variables.

Also, note that what is being correlated are the residual errors of the regression – only the uncertain portion of the variable movements. Variables may exhibit similar expected shapes – both loads and electricity prices are higher during the week than on the weekend. This coincidence is captured in the expected weekly shapes input into the planning model. The correlation calculated here captures the extent to which the shocks experienced by two different variables tend to have similar direction and magnitude. The resulting short-term correlations by season are reported below.

Table H.6 - Short-term Winter Correlations

	K-O	SUMAS	4C	COB	Mid-C	PV	CA	ID	Portland	OR Other	UT	WA	WY	Hydro
K-O	100%	69%	40%	30%	34%	45%	1%	-5%	10%	1%	2%	5%	-1%	-12%
SUMAS	69%	100%	20%	26%	29%	24%	7%	6%	11%	6%	1%	13%	3%	-16%
4C	40%	20%	100%	58%	52%	89%	13%	2%	8%	15%	20%	17%	9%	1%
COB	30%	26%	58%	100%	72%	57%	18%	1%	9%	22%	12%	28%	8%	-2%
Mid-C	34%	29%	52%	72%	100%	56%	14%	0%	19%	26%	12%	31%	5%	-3%
PV	45%	24%	89%	57%	56%	100%	8%	-1%	4%	9%	14%	13%	7%	-3%
CA	1%	7%	13%	18%	14%	8%	100%	16%	46%	78%	28%	45%	17%	10%
ID	-5%	6%	2%	1%	0%	-1%	16%	100%	24%	26%	35%	28%	23%	9%
Portland	10%	11%	8%	9%	19%	4%	46%	24%	100%	69%	40%	64%	32%	10%
OR Other	1%	6%	15%	22%	26%	9%	78%	26%	69%	100%	40%	67%	25%	16%
UT	2%	1%	20%	12%	12%	14%	28%	35%	40%	40%	100%	33%	50%	4%
WA	5%	13%	17%	28%	31%	13%	45%	28%	64%	67%	33%	100%	28%	15%
WY	-1%	3%	9%	8%	5%	7%	17%	23%	32%	25%	50%	28%	100%	0%
Hydro	-12%	-16%	1%	-2%	-3%	-3%	10%	9%	10%	16%	4%	15%	0%	100%

Deviation events that impact one part of PacifiCorp's system do not necessarily affect other parts of the system, due to its geographic diversity and transmission constraints. The correlation between these different deviations can be low if the deviations are caused by different drivers. An example from the winter season is the nine percent correlation between the Southeast Idaho load area, which is driven by weather events in PacifiCorp's PACE balancing area, and Hydro, which is predominantly driven by weather events in PacifiCorp's PACW balancing area, the unit commitment stack and unplanned unit outages.

Table H.7 - Short-term Spring Correlations

	K-O	SUMAS	4C	COB	Mid-C	PV	CA	ID	Portland	OR Other	UT	WA	WY	Hydro
K-O	100%	62%	16%	13%	14%	13%	5%	19%	8%	14%	13%	10%	9%	3%
SUMAS	62%	100%	15%	19%	14%	8%	-3%	17%	10%	10%	17%	16%	10%	-5%
4C	16%	15%	100%	38%	41%	72%	18%	10%	26%	27%	20%	22%	5%	5%
COB	13%	19%	38%	100%	58%	28%	18%	1%	22%	26%	11%	28%	6%	12%
Mid-C	14%	14%	41%	58%	100%	27%	19%	0%	20%	21%	3%	29%	3%	7%
PV	13%	8%	72%	28%	27%	100%	16%	7%	22%	18%	15%	14%	9%	1%
CA	5%	-3%	18%	18%	19%	16%	100%	10%	43%	66%	17%	42%	14%	-4%
ID	19%	17%	10%	1%	0%	7%	10%	100%	-4%	6%	50%	11%	14%	3%
Portland	8%	10%	26%	22%	20%	22%	43%	-4%	100%	70%	13%	57%	24%	-11%
OR Other	14%	10%	27%	26%	21%	18%	66%	6%	70%	100%	19%	65%	29%	-3%
UT	13%	17%	20%	11%	3%	15%	17%	50%	13%	19%	100%	22%	27%	-14%
WA	10%	16%	22%	28%	29%	14%	42%	11%	57%	65%	22%	100%	15%	-2%
WY	9%	10%	5%	6%	3%	9%	14%	14%	24%	29%	27%	15%	100%	-17%
Hydro	3%	-5%	5%	12%	7%	1%	-4%	3%	-11%	-3%	-14%	-2%	-17%	100%

Similarly, the spring season shows a very low correlation of 14 percent between the Northern California and Wyoming loads, which are driven by different local weather deviations and different customer types. Wyoming loads are mostly driven by large industrial customers, whose loads are relatively flat across the year.

Table H.8 - Short-term Summer Correlations

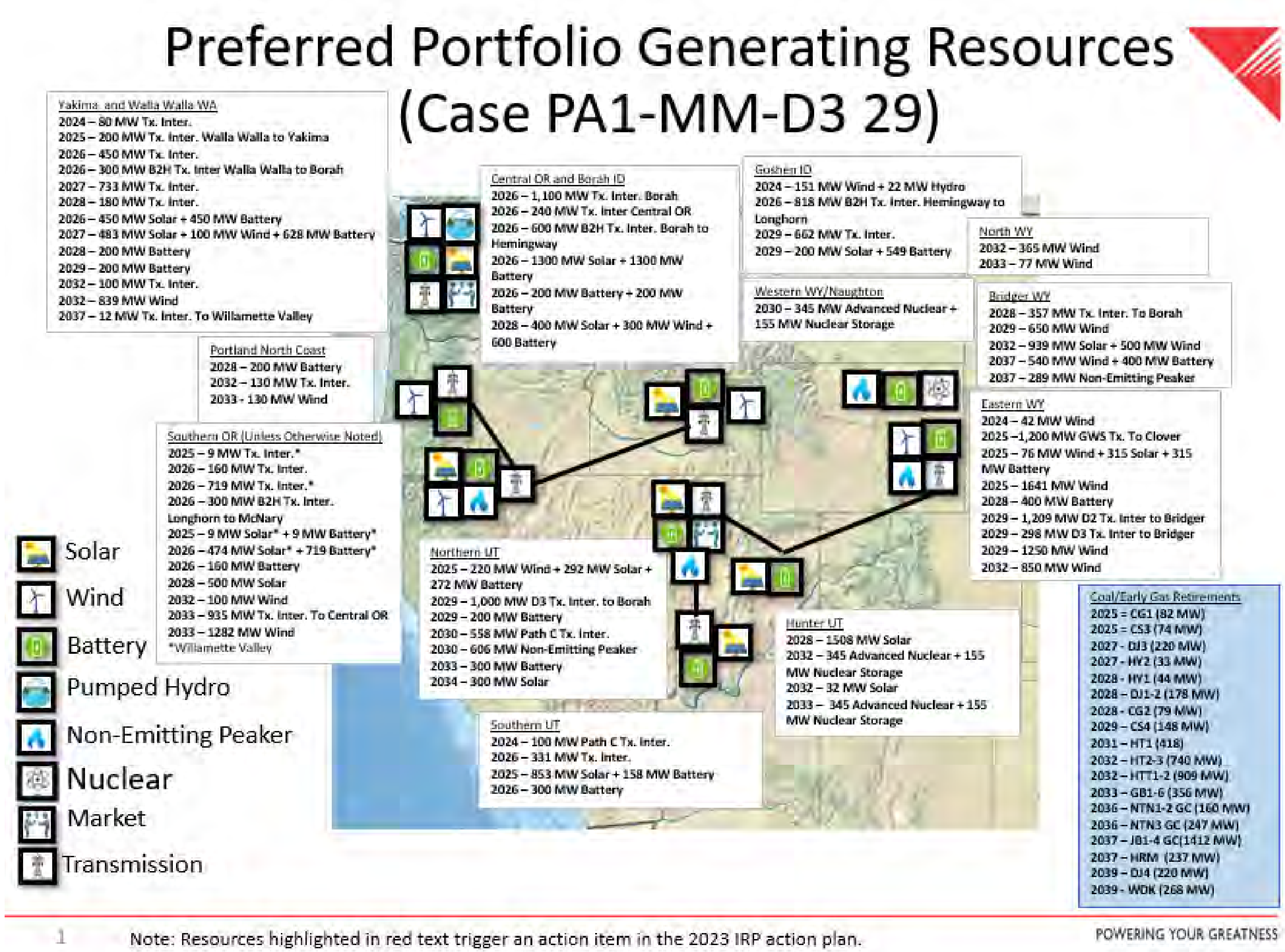
	K-O	SUMAS	4C	COB	Mid-C	PV	CA	ID	Portland	OR Other	UT	WA	WY	Hydro
K-O	100%	81%	13%	11%	23%	13%	1%	-4%	8%	4%	-2%	11%	-5%	-1%
SUMAS	81%	100%	11%	6%	21%	7%	1%	-1%	8%	3%	-1%	8%	-4%	1%
4C	13%	11%	100%	22%	40%	78%	19%	6%	26%	22%	26%	21%	10%	-3%
COB	11%	6%	22%	100%	61%	29%	14%	4%	20%	20%	20%	27%	5%	-4%
Mid-C	23%	21%	40%	61%	100%	47%	18%	-2%	39%	34%	5%	30%	0%	-3%
PV	13%	7%	78%	29%	47%	100%	21%	10%	28%	25%	26%	26%	13%	-1%
CA	1%	1%	19%	14%	18%	21%	100%	39%	44%	73%	30%	60%	9%	-9%
ID	-4%	-1%	6%	4%	-2%	10%	39%	100%	6%	19%	49%	17%	31%	0%
Portland	8%	8%	26%	20%	39%	28%	44%	6%	100%	77%	13%	62%	-4%	-1%
OR Other	4%	3%	22%	20%	34%	25%	73%	19%	77%	100%	18%	82%	3%	-2%
UT	-2%	-1%	26%	20%	5%	26%	30%	49%	13%	18%	100%	18%	43%	-5%
WA	11%	8%	21%	27%	30%	26%	60%	17%	62%	82%	18%	100%	5%	-6%
WY	-5%	-4%	10%	5%	0%	13%	9%	31%	-4%	3%	43%	5%	100%	-4%
Hydro	-1%	1%	-3%	-4%	-3%	-1%	-9%	0%	-1%	-2%	-5%	-6%	-4%	100%

In the summer season, 13 percent correlation has been observed between the deviations of Kern-Opal gas prices and Palo Verde power prices. Palo Verde prices are driven by a resource mix of southwest nuclear operations and gas unit dispatch based off SoCal gas prices. The operations of gas storage facilities and physical planned and unplanned maintenance of Kern-Opal and SoCal pipelines are independent of each other.

Table H.9 - Short-term Fall Correlations

	K-O	SUMAS	4C	COB	Mid-C	PV	CA	ID	Portland	OR Other	UT	WA	WY	Hydro
K-O	100%	20%	5%	13%	12%	3%	19%	-16%	9%	17%	-3%	9%	9%	1%
SUMAS	20%	100%	-1%	-9%	-3%	3%	5%	-3%	4%	5%	-3%	1%	6%	7%
4C	5%	-1%	100%	30%	26%	77%	13%	-3%	1%	8%	24%	10%	-7%	-15%
COB	13%	-9%	30%	100%	71%	37%	25%	-1%	28%	26%	13%	27%	11%	-19%
Mid-C	12%	-3%	26%	71%	100%	34%	23%	-3%	38%	34%	13%	32%	11%	-10%
PV	3%	3%	77%	37%	34%	100%	14%	-1%	2%	7%	17%	6%	-6%	-14%
CA	19%	5%	13%	25%	23%	14%	100%	27%	55%	80%	36%	60%	19%	8%
ID	-16%	-3%	-3%	-1%	-3%	-1%	27%	100%	26%	22%	43%	28%	22%	8%
Portland	9%	4%	1%	28%	38%	2%	55%	26%	100%	78%	37%	69%	33%	-1%
OR Other	17%	5%	8%	26%	34%	7%	80%	22%	78%	100%	41%	77%	32%	6%
UT	-3%	-3%	24%	13%	13%	17%	36%	43%	37%	41%	100%	43%	35%	1%
WA	9%	1%	10%	27%	32%	6%	60%	28%	69%	77%	43%	100%	34%	8%
WY	9%	6%	-7%	11%	11%	-6%	19%	22%	33%	32%	35%	34%	100%	3%
Hydro	1%	7%	-15%	-19%	-10%	-14%	8%	8%	-1%	6%	1%	8%	3%	100%

In the fall, a low correlation of 11 percent has been observed between Mid-C market price deviations and Wyoming load deviations. Market deviations are due to deviations in northwest weather patterns and resource mix while Wyoming loads are mostly dictated by planned or unplanned outages of industrial customer class.



Preferred Portfolio Generating Resources
(Case PA1-MM-D3 29)
Yakima and Walla Walla WA
2024 – 80 MW Tx. Inter.
2025 – 200 MW Tx. Inter. Walla Walla to Yakima
2026 – 450 MW Tx. Inter.
2026 – 300 MW B2H Tx. Inter Walla Walla to Borah
2027 – 733 MW Tx. Inter.
2028 – 180 MW Tx. Inter.
2026 – 450 MW Solar + 450 MW Battery
2027 – 483 MW Solar + 100 MW Wind + 628 MW Battery
2028 – 200 MW Battery
2029 – 200 MW Battery
2032 – 100 MW Tx. Inter.
2032 – 839 MW Wind
2037 – 12 MW Tx. Inter. To Willamette Valley
Central OR and Borah ID
2026 – 1,100 MW Tx. Inter. Borah
2026 – 240 MW Tx. Inter Central OR
2026 – 600 MW B2H Tx. Inter. Borah to Hemingway
2026 – 1300 MW Solar + 1300 MW Battery
2026 – 200 MW Battery + 200 MW Battery
2028 – 400 MW Solar + 300 MW Wind + 600 Battery
Goshen ID
2024 – 151 MW Wind + 22 MW Hydro
2026 – 818 MW B2H Tx. Inter. Hemingway to Longhorn
2029 – 662 MW Tx. Inter.
2029 – 200 MW Solar + 549 Battery
North WY
2032 – 365 MW Wind
2033 – 77 MW Wind
Western WY/Naughton
2030 – 345 MW Advanced Nuclear + 155 MW Nuclear Storage
Bridger WY
2028 – 357 MW Tx. Inter. To Borah
2029 – 650 MW Wind
2032 – 939 MW Solar + 500 MW Wind
2037 – 540 MW Wind + 400 MW Battery
2037 – 289 MW Non-Emitting Peaker
Portland North Coast
2028 – 200 MW Battery
2032 – 130 MW Tx. Inter.
2033 - 130 MW Wind
Southern OR (Unless Otherwise Noted)
2025 – 9 MW Tx. Inter.*
2026 – 160 MW Tx. Inter.
2026 – 719 MW Tx. Inter.*
2026 – 300 MW B2H Tx. Inter. Longhorn to McNary
2025 – 9 MW Solar* + 9 MW Battery*
2026 – 474 MW Solar* + 719 Battery*
2026 – 160 MW Battery
2028 – 500 MW Solar
2032 – 100 MW Wind
2033 – 935 MW Tx. Inter. To Central OR
2033 – 1282 MW Wind
*Willamette Valley
Eastern WY
2024 – 42 MW Wind
2025 –1,200 MW GWS Tx. To Clover
2025 – 76 MW Wind + 315 Solar + 315 MW Battery
2025 – 1641 MW Wind
2028 – 400 MW Battery
2029 – 1,209 MW D2 Tx. Inter to Bridger
2029 – 298 MW D3 Tx. Inter to Bridger
2029 – 1250 MW Wind
2032 – 850 MW Wind
Northern UT
2025 – 220 MW Wind + 292 MW Solar + 272 MW Battery
2029 – 1,000 MW D3 Tx. Inter. to Borah
2029 – 200 MW Battery
2030 – 558 MW Path C Tx. Inter.
2030 – 606 MW Non-Emitting Peaker
2033 – 300 MW Battery
2034 – 300 MW Solar
Hunter UT
2028 – 1508 MW Solar
2032 – 345 Advanced Nuclear + 155 MW Nuclear Storage
2032 – 32 MW Solar
2033 – 345 Advanced Nuclear + 155 MW Nuclear Storage
Southern UT
2024 – 100 MW Path C Tx. Inter.
2026 – 331 MW Tx. Inter.
2025 – 853 MW Solar + 158 MW Battery
2026 – 300 MW Battery
Coal/Early Gas Retirements
2025 – CG1 (82 MW)
2025 – CS3 (74 MW)
2027 - DJ3 (220 MW)
2027 - HY2 (33 MW)
2028 - HY1 (44 MW)
2028 – DJ1-2 (178 MW)
2028 - CG2 (79 MW)
2029 – CS4 (148 MW)
2031 – HT1 (418)
2032 – HT2-3 (740 MW)
2032 – HTT1-2 (909 MW)
2033 – GB1-6 (356 MW)
2036 – NTN1-2 GC (160 MW)
2036 – NTN3 GC (247 MW)
2037 – JB1-4 GC(1412 MW)
2037 – HRM (237 MW)
2039 – DJ4 (220 MW)
2039 - WDK (268 MW)
Solar
Wind
Battery
Pumped Hydro
Non-Emitting Peaker
Nuclear
Market
Transmission
1
Note: Resources highlighted in red text trigger an action item in the 2023 IRP action plan.
POWERING YOUR GREATNESS

P10-Offshore Wind

Summary Portfolio Capacity by Resource Type and Year, Installed MW																					
	Installed Capacity, MW																				
Resource	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	Total
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	606	-	-	-	-	-	-	289	-	-	-	-	-	895
DSM - Energy Efficiency	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426	4,953
DSM - Demand Response	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-	929
Renewable - Wind	-	194	1,937	-	100	300	1,900	-	-	2,683	1,459	-	-	-	540	-	-	-	-	-	9,113
Renewable - Utility Solar	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-	7,855
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	500	-	-	-	-	-	8,210
Renewable - Battery (Long Duration)	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-	350
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-	1,500
Front Office - Selected Markets	987	1,000	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	149
Front Office Transactions - Winter	1,640	1,781	1,035	553	553	524	166	195	231	52	41	52	52	52	52	52	52	52	29	32	360
Front Office Transactions - Summer	1,683	1,874	1,637	1,525	1,535	586	547	535	587	158	63	47	50	61	33	85	111	163	208	198	584
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-	(1,141)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-	(2,335)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	-	-	-	(699)	-	-	-	-	-	-	-	-	-	-	-	-	(1,770)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	-	-	(356)	-	-	(247)	(237)	-	-	-	-	(593)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,729**	**5,086**	**8,443**	**7,803**	**3,646**	**5,264**	**3,897**	**1,965**	**1,505**	**4,059**	**889**	**228**	**271**	**390**	**1,591**	**(1,130)**	**352**	**(195)**	**376**	**656**	

W-10 SC CETA

Summary Portfolio Capacity by Resource Type and Year, Installed MW																					
	Installed Capacity, MW																				
Resource	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	Total
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	-	-	606	-	-	-	-	634	-	-	-	-	-	1,240
DSM - Energy Efficiency	123	220	259	206	225	230	245	265	637	114	160	170	162	288	586	165	170	165	158	429	4,977
DSM - Demand Response	72	39	154	107	123	75	27	-	46	-	-	-	3	-	-	246	19	19	-	-	930
Renewable - Wind	-	194	1,717	-	-	457	500	120	-	6,486	3,607	-	-	-	-	-	-	-	-	-	13,081
Renewable - Utility Solar	-	-	1,469	1,600	-	2,589	1,298	120	108	600	-	841	-	-	-	-	-	-	-	-	8,625
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	954	1,600	-	1,979	1,647	-	-	600	-	-	-	-	1,207	-	-	-	-	-	7,987
Renewable - Battery (Long Duration)	-	-	-	-	-	400	-	-	-	-	-	-	-	-	784	-	-	-	-	-	1,184
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	27	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	500	-	-	500	500	-	-	-	-	-	-	-	-	1,500
Front Office - Selected Markets	963	1,000	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	148
Front Office Transactions - Winter	1,572	1,745	1,383	805	940	474	368	506	613	176	171	57	38	38	129	125	127	121	160	165	486
Front Office Transactions - Summer	1,656	1,869	1,699	1,769	1,854	630	571	572	595	95	6	-	-	-	-	-	-	-	-	-	566
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	(699)	-	-	-	-	-	-	-	(330)	-	-	(1,840)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	(2,067)	-	-	-	-	-	-	-	(268)	-	-	(2,335)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	-	-	-	-	-	-	-	-	-	-	(370)	(713)	-	-	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,070)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	(119)	-	(237)	-	-	(247)	(237)	-	-	(64)	-	(657)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,610**	**5,045**	**8,635**	**6,045**	**3,150**	**6,581**	**4,328**	**1,935**	**1,999**	**5,792**	**4,444**	**1,331**	**203**	**326**	**2,723**	**(414)**	**316**	**(293)**	**254**	**594**	

S-08 New Load FlatLoad Increase

Summary Portfolio Capacity by Resource Type and Year, Installed MW

Resource	Installed Capacity, MW 2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	Total
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	606	-	-	881	-	-	345	289	-	-	-	-	-	2,121
DSM - Energy Efficiency	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426	4,953
DSM - Demand Response	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-	929
Renewable - Wind	-	194	1,937	-	100	300	1,900	-	-	2,783	3,359	-	-	-	540	-	-	-	-	-	11,113
Renewable - Utility Solar	-	-	1,469	2,524	483	1,907	200	-	-	972	1,600	300	-	-	-	-	-	-	-	-	9,455
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	954	2,929	628	1,900	1,149	-	-	-	1,750	-	-	-	200	-	-	-	-	-	9,510
Renewable - Battery (Long Duration)	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-	350
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-	1,500
Front Office - Selected Markets	899	1,000	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	145
Front Office Transactions - Winter	1,640	1,781	1,035	553	553	524	166	195	231	52	27	27	27	27	37	38	38	39	9	10	350
Front Office Transactions - Summer	1,683	1,874	1,637	1,525	1,535	586	547	535	587	158	47	18	26	45	30	33	88	107	100	148	565
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-	(1,141)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-	(2,335)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	-	-	-	(699)	-	-	-	-	-	-	-	-	-	-	-	-	(1,770)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	-	-	(356)	-	-	(247)	(237)	-	-	-	-	(593)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,641**	**5,086**	**8,443**	**7,803**	**3,646**	**5,264**	**3,897**	**1,965**	**1,505**	**4,159**	**6,840**	**174**	**222**	**694**	**1,273**	**(1,196)**	**315**	**(264)**	**248**	**584**	

P11-Max NG

Summary Portfolio Capacity by Resource Type and Year, Installed MW																					
	Installed Capacity, MW																				
Resource	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	Total
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	1,044	-	-	-	-	500	-	-	522	-	(1,044)	1,022
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	283	-	-	-	-	-	283
NonEmitting Peaker	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426	4,953
DSM - Demand Response	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-	929
Renewable - Wind	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-	9,113
Renewable - Utility Solar	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-	7,855
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-	7,910
Renewable - Battery (Long Duration)	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-	350
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Front Office - Selected Markets	1,000	1,000	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	150
Front Office Transactions - Winter	1,640	1,781	1,035	553	553	524	166	279	281	52	41	52	52	52	52	52	52	52	47	38	368
Front Office Transactions - Summer	1,683	1,874	1,637	1,525	1,535	586	547	598	595	195	163	158	170	191	132	179	281	170	262	303	639
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-	(1,141)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-	(2,335)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	-	-	-	(699)	-	-	-	-	-	-	-	-	-	-	-	-	(1,770)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	-	-	(356)	-	-	(247)	(237)	-	-	-	-	(593)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,742**	**5,086**	**8,443**	**7,803**	**3,646**	**5,264**	**3,897**	**1,006**	**1,563**	**4,740**	**389**	**339**	**391**	**520**	**1,884**	**(1,036)**	**522**	**334**	**448**	**(277)**	

P15-No GWS

Summary Portfolio Capacity by Resource Type and Year, Installed MW																					
	Installed Capacity, MW																				
Resource	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	Total
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-	1,240
DSM - Energy Efficiency	123	220	259	198	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426	4,954
DSM - Demand Response	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-	929
Renewable - Wind	-	194	296	-	100	300	-	-	-	2,349	1,282	-	-	-	-	-	-	-	-	-	4,521
Renewable - Utility Solar	-	-	1,469	2,224	483	2,307	600	-	200	972	-	300	-	-	-	-	-	-	-	-	8,555
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	954	2,629	628	2,500	1,349	-	-	800	150	-	-	-	200	-	-	-	-	-	9,210
Renewable - Battery (Long Duration)	-	-	-	-	-	-	-	-	-	600	150	-	-	-	200	-	-	-	-	-	950
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	500	-	500	500	-	-	-	1,000	-	-	-	-	-	2,500
Front Office - Selected Markets	1,000	1,000	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	150
Front Office Transactions - Winter	1,640	1,781	1,816	977	1,085	950	974	919	938	440	315	316	316	316	422	565	657	679	737	839	834
Front Office Transactions - Summer	1,683	1,874	1,836	1,866	1,826	633	647	632	632	408	196	195	191	191	120	179	207	235	312	369	712
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	(330)	-	-	-	-	-	(1,141)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	(418)	(1,649)	-	-	-	(268)	-	-	-	-	-	(2,335)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(1,783)	-	-	-	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	-	-	-	(699)	-	-	-	-	-	-	-	-	-	-	-	-	(1,770)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	-	-	(356)	-	-	(247)	(237)	-	-	-	-	(593)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,742**	**5,086**	**7,782**	**7,969**	**4,469**	**6,737**	**3,505**	**2,786**	**2,457**	**5,763**	**1,119**	**640**	**676**	**1,129**	**197**	**890**	**1,053**	**1,102**	**1,188**	**1,634**	

P16-No B2H

Summary Portfolio Capacity by Resource Type and Year, Installed MW

	Installed Capacity, MW																				
Resource	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**Total**
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-	1,240
DSM - Energy Efficiency	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426	4,953
DSM - Demand Response	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-	929
Renewable - Wind	-	194	1,937	-	100	-	1,900	400	-	2,783	959	-	-	-	540	-	-	-	-	-	8,813
Renewable - Utility Solar	-	-	1,469	2,524	483	1,507	600	-	-	972	600	300	-	-	-	-	-	-	-	-	8,455
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	954	2,929	1,352	1,900	1,149	-	-	-	750	-	-	-	200	-	-	-	-	-	9,234
Renewable - Battery (Long Duration)	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-	350
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-	1,500
Front Office - Selected Markets	1,000	1,000	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	150
Front Office Transactions - Winter	1,640	1,781	1,035	553	556	539	170	177	195	52	41	52	52	52	52	52	52	65	47	106	363
Front Office Transactions - Summer	1,683	1,874	1,637	1,525	1,535	622	558	516	585	147	50	47	47	47	34	51	129	156	204	205	583
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-	(1,141)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-	(2,335)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	-	-	-	(699)	-	-	-	-	-	-	-	-	-	-	-	-	(1,770)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	-	-	(356)	-	-	(247)	(237)	-	-	-	-	(593)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,742**	**5,086**	**8,443**	**7,803**	**4,373**	**4,615**	**4,312**	**2,328**	**1,467**	**4,148**	**1,576**	**228**	**268**	**721**	**1,292**	**(1,164)**	**370**	**(189)**	**390**	**737**	

P-MN

Summary Portfolio Capacity by Resource Type and Year, Installed MW

	Installed Capacity, MW																				
Resource	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	Total
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	-	-	-	-	-	303	578	345	-	-	-	-	-	1,226
DSM - Energy Efficiency	123	220	259	198	217	221	243	259	637	105	160	170	161	288	586	164	170	165	139	412	4,897
DSM - Demand Response	72	39	152	99	126	94	27	13	35	-	-	-	-	-	1	228	19	19	-	-	924
Renewable - Wind	-	194	1,717	-	-	-	500	-	-	6,025	3,565	-	450	-	-	-	-	-	-	-	12,451
Renewable - Utility Solar	-	-	1,469	1,600	-	2,470	1,298	-	254	941	-	-	-	-	600	-	-	-	-	-	8,632
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	954	1,600	-	2,304	1,647	-	-	600	-	-	-	-	2,356	-	-	-	-	-	9,461
Renewable - Battery (Long Duration)	-	-	-	-	-	400	-	-	-	-	-	-	-	-	-	-	-	-	-	-	400
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	27	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	500	-	1,000	-	-	-	-	-	-	-	-	-	-	1,500
Front Office - Selected Markets	963	1,000	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	148
Front Office Transactions - Winter	1,640	1,781	1,405	766	831	635	624	624	667	254	65	90	51	69	63	179	245	258	168	182	530
Front Office Transactions - Summer	1,683	1,874	1,764	1,835	1,966	650	617	620	636	47	-	4	-	-	-	-	-	-	-	1	585
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-	(1,141
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	(2,067)	-	-	-	-	-	-	-	(268)	-	-	(2,335
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	-	-	-	340	(354)	-	-	-	-	(160)	(210)	(699)	-	-	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	-	-	-	(699)	-	-	-	-	-	-	-	-	-	-	-	-	(1,770
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	-	-	(356)	-	-	(247)	(237)	-	-	(64)	-	(657
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,705**	**5,086**	**8,720**	**6,056**	**3,148**	**6,521**	**4,628**	**1,509**	**1,875**	**6,905**	**3,790**	**(92)**	**965**	**775**	**3,494**	**(365)**	**434**	**(156)**	**243**	**595**	

P-LN

Summary Portfolio Capacity by Resource Type and Year, Installed MW

	Installed Capacity, MW																				
Resource	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**Total**
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	-	-	303	-	-	-	-	1,240	-	-	-	-	-	1,543
DSM - Energy Efficiency	123	220	259	197	216	219	240	258	637	103	160	170	161	281	586	163	170	165	139	412	4,879
DSM - Demand Response	72	39	143	38	161	120	33	16	33	-	-	-	51	-	-	170	19	19	-	-	914
Renewable - Wind	-	194	1,717	-	-	-	500	-	11	5,477	1,821	-	-	-	-	-	-	-	-	-	9,720
Renewable - Utility Solar	-	-	1,469	1,600	-	2,519	1,298	-	288	241	-	-	-	-	1,400	-	-	-	-	-	8,815
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	954	1,600	160	2,008	1,647	-	-	-	400	-	-	-	2,560	-	-	-	-	-	9,329
Renewable - Battery (Long Duration)	-	-	-	-	-	600	-	-	-	-	-	-	-	-	200	-	-	-	-	-	800
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	27	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	500	-	1,000	-	-	-	-	-	-	-	-	-	-	1,500
Front Office - Selected Markets	1,000	1,000	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	150
Front Office Transactions - Winter	1,572	1,745	1,187	776	822	718	620	726	757	108	78	69	78	69	87	72	103	181	158	160	504
Front Office Transactions - Summer	1,656	1,869	1,665	2,003	2,040	660	620	596	591	66	70	79	74	72	10	38	71	78	59	30	617
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	-	-	-	(811)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	(2,067)	-	-	-	-	-	-	-	-	-	-	(2,067)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	598	-	-	699	-	(330)	-	-	-	-	(370)	(1,413)	-	(268)	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	(598)	-	-	(699)	-	-	-	-	-	-	-	-	-	-	-	-	(2,368)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	(119)	-	(237)	-	-	(247)	(237)	-	-	(64)	-	(657)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,647**	**5,045**	**8,394**	**6,172**	**3,407**	**6,591**	**4,630**	**1,948**	**2,317**	**4,782**	**2,529**	**81**	**364**	**422**	**5,466**	**(1,207)**	**363**	**175**	**292**	**602**	

P-SC

Summary Portfolio Capacity by Resource Type and Year, Installed MW

Resource	Installed Capacity, MW																				
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	Total
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	-	-	606	-	-	-	-	634	-	-	-	-	-	1,240
DSM - Energy Efficiency	123	220	259	206	225	230	245	265	637	114	160	170	162	288	586	165	170	165	158	429	4,977
DSM - Demand Response	72	39	154	107	123	75	27	-	46	-	-	-	3	-	-	246	19	19	-	-	930
Renewable - Wind	-	194	1,717	-	-	457	500	-	-	6,486	3,607	-	-	-	-	-	-	-	-	-	12,961
Renewable - Utility Solar	-	-	1,469	1,600	-	2,589	1,298	-	108	600	-	841	-	-	-	-	-	-	-	-	8,505
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	954	1,600	-	1,979	1,647	-	-	600	-	-	-	-	1,207	-	-	-	-	-	7,987
Renewable - Battery (Long Duration)	-	-	-	-	-	400	-	-	-	-	-	-	-	-	784	-	-	-	-	-	1,184
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	27	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	500	-	-	500	500	-	-	-	-	-	-	-	-	1,500
Front Office - Selected Markets	930	999	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	146
Front Office Transactions - Winter	1,572	1,745	1,383	805	940	474	368	520	626	184	171	57	41	39	148	126	128	121	164	169	489
Front Office Transactions - Summer	1,656	1,869	1,699	1,769	1,854	630	571	578	595	118	10	-	-	-	-	-	-	-	-	-	567
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	(699)	-	-	-	-	-	-	-	(330)	-	-	(1,840)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	(2,067)	-	-	-	-	-	-	-	(268)	-	-	(2,335)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	-	-	-	-	-	-	-	-	-	-	(370)	(713)	-	-	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,070)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	(119)	-	(237)	-	-	(247)	(237)	-	-	(64)	-	(657)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,577**	**5,044**	**8,635**	**6,045**	**3,150**	**6,581**	**4,328**	**1,715**	**2,012**	**5,823**	**4,448**	**1,331**	**206**	**327**	**2,742**	**(413)**	**317**	**(293)**	**258**	**598**	

P-HH

Summary Portfolio Capacity by Resource Type and Year, Installed MW																					
	Installed Capacity, MW																				
Resource	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**Total**
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	-	-	-	-	-	-	-	951	-	-	-	-	-	951
DSM - Energy Efficiency	123	220	259	210	229	234	255	266	675	116	161	185	162	289	594	165	187	176	172	671	5,349
DSM - Demand Response	72	39	154	119	117	81	26	-	37	5	13	12	26	-	-	239	22	19	-	-	981
Renewable - Wind	-	194	1,717	-	-	174	500	-	-	7,922	2,321	-	-	-	-	-	-	-	-	-	12,828
Renewable - Utility Solar	-	-	1,469	1,600	-	3,006	1,298	-	4	1,288	241	-	-	-	-	-	-	-	-	-	8,906
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	954	1,600	-	2,599	1,647	-	-	600	-	-	-	-	1,541	-	-	-	-	-	8,941
Renewable - Battery (Long Duration)	-	-	-	-	-	600	-	-	-	-	-	-	-	-	200	-	-	-	-	-	800
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	27	-	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	500	-	1,000	-	-	-	-	500	-	-	-	-	-	2,000
Front Office - Selected Markets	993	1,000	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	150
Front Office Transactions - Winter	1,572	1,745	1,254	864	910	556	551	511	613	101	31	31	31	37	21	65	117	175	131	167	474
Front Office Transactions - Summer	1,656	1,869	1,656	1,783	1,955	622	575	568	587	11	11	23	11	11	7	11	11	11	3	3	569
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-	(1,141)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	(2,067)	-	-	-	-	-	-	-	(268)	-	-	(2,335)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	-	-	-	(699)	-	-	-	-	-	-	-	-	-	-	-	-	(1,770)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	(119)	(237)	(237)	-	-	(247)	-	-	-	(500)	-	(1,093)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,640**	**5,045**	**8,463**	**6,134**	**3,211**	**7,627**	**4,524**	**1,697**	**1,916**	**8,857**	**2,541**	**14**	**230**	**337**	**3,197**	**(933)**	**337**	**(217)**	**(194)**	**841**	

P14-All GW

Summary Portfolio Capacity by Resource Type and Year, Installed MW

	Installed Capacity, MW																				
Resource	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**Total**
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-	1,240
DSM - Energy Efficiency	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426	4,953
DSM - Demand Response	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-	929
Renewable - Wind	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-	9,113
Renewable - Utility Solar	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-	7,855
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-	7,910
Renewable - Battery (Long Duration)	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-	350
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-	1,500
Front Office - Selected Markets	1,000	1,000	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	150
Front Office Transactions - Winter	1,195	1,453	696	482	607	518	166	195	231	52	41	52	52	52	52	52	52	62	46	85	307
Front Office Transactions - Summer	1,556	1,709	1,417	1,547	1,524	582	547	535	587	159	83	53	66	65	48	120	132	182	231	252	570
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-	(1,141)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-	(2,335)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	-	-	-	(699)	-	-	-	-	-	-	-	-	-	-	-	-	(1,770)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	-	-	(356)	-	-	(247)	(237)	-	-	-	-	(593)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,170**	**4,593**	**7,884**	**7,754**	**3,689**	**5,254**	**3,897**	**1,965**	**1,505**	**4,160**	**809**	**234**	**287**	**739**	**1,306**	**(1,095)**	**373**	**(166)**	**416**	**763**	

P13-All EE

Summary Portfolio Capacity by Resource Type and Year, Installed MW

	Installed Capacity, MW																				
Resource	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**Total**
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-	1,240
DSM - Energy Efficiency	123	220	259	289	330	334	392	457	1,016	215	301	283	292	457	816	230	253	241	343	1,231	8,082
DSM - Demand Response	72	39	152	109	119	91	29	13	35	-	1	-	2	-	4	265	70	20	-	778	1,799
Renewable - Wind	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-	9,113
Renewable - Utility Solar	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-	7,855
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-	7,910
Renewable - Battery (Long Duration)	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-	350
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-	1,500
Front Office - Selected Markets	1,000	995	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	150
Front Office Transactions - Winter	1,640	1,781	1,035	552	529	481	124	164	173	52	41	52	52	41	52	52	52	52	29	21	349
Front Office Transactions - Summer	1,683	1,874	1,637	1,515	1,516	573	529	480	564	150	53	47	47	47	30	35	102	109	124	141	563
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-	(1,141)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-	(2,335)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	-	-	-	(699)	-	-	-	-	-	-	-	-	-	-	-	-	(1,770)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	-	-	(356)	-	-	(247)	(237)	-	-	-	-	(593)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,742**	**5,081**	**8,443**	**7,884**	**3,705**	**5,333**	**3,995**	**2,072**	**1,788**	**4,254**	**906**	**326**	**393**	**890**	**1,514**	**(1,068)**	**477**	**(176)**	**496**	**2,171**	

P12-RET Coal 30 NG 40

Summary Portfolio Capacity by Resource Type and Year, Installed MW

Resource	Installed Capacity, MW																				
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	Total
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	606	-	-	-	-	-	345	1,790	-	-	-	-	-	2,741
DSM - Energy Efficiency	123	954	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426	5,687
DSM - Demand Response	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-	929
Renewable - Wind	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	676	-	-	-	-	-	9,249
Renewable - Utility Solar	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-	7,855
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	754	2,929	824	1,900	1,149	-	-	-	150	-	-	-	1,323	-	-	-	-	(196)	8,833
Renewable - Battery (Long Duration)	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-	350
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	500
Front Office - Selected Markets	1,000	1,000	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	150
Front Office Transactions - Winter	1,640	1,702	758	296	413	298	79	111	153	52	52	52	52	52	458	549	584	841	876	933	498
Front Office Transactions - Summer	1,683	1,783	1,382	1,138	1,073	530	346	375	423	149	89	66	66	75	508	481	498	545	585	590	619
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	-	-	-	(811)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	(450)	-	-	-	-	(418)	(1,199)	-	-	-	-	-	-	-	-	-	(2,067)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	598	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	(598)	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	(598)	-	-	(699)	-	-	-	-	-	-	-	-	-	-	-	-	(2,368)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	-	-	(356)	-	-	(2,781)	-	-	-	-	-	(2,890)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,742**	**5,650**	**7,711**	**7,159**	**2,790**	**4,982**	**3,609**	**1,721**	**1,263**	**3,650**	**776**	**247**	**287**	**749**	**2,398**	**0**	**1,271**	**976**	**1,600**	**1,753**	

P08-No D3-D2

Summary Portfolio Capacity by Resource Type and Year, Installed MW

Resource	Installed Capacity, MW																				Total
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-	1,240
DSM - Energy Efficiency	123	220	259	198	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426	4,954
DSM - Demand Response	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-	929
Renewable - Wind	-	194	1,937	-	100	300	-	-	-	2,349	1,282	-	-	-	-	-	-	-	-	-	6,162
Renewable - Utility Solar	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-	7,855
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	954	2,929	628	1,900	1,149	-	-	800	150	-	-	-	200	-	-	-	-	-	8,710
Renewable - Battery (Long Duration)	-	-	-	-	-	-	-	-	-	600	150	-	-	-	200	-	-	-	-	-	950
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	500	-	500	500	-	-	-	1,000	-	-	-	-	-	2,500
Front Office - Selected Markets	1,000	1,000	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	150
Front Office Transactions - Winter	1,640	1,781	1,035	553	553	525	632	594	613	236	78	107	79	105	80	160	249	374	446	547	519
Front Office Transactions - Summer	1,683	1,874	1,637	1,525	1,535	586	607	608	631	353	192	186	191	191	97	139	136	196	268	269	645
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-	(1,141)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-	(2,335)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	-	-	-	(699)	-	-	-	-	-	-	-	-	-	-	-	-	(1,770)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	-	-	(356)	-	-	(247)	(237)	-	-	-	-	(593)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,742**	**5,086**	**8,443**	**7,804**	**3,646**	**5,265**	**2,523**	**2,437**	**1,931**	**5,504**	**878**	**422**	**439**	**918**	**1,843**	**(968)**	**574**	**160**	**853**	**1,242**	

P07-D3-D2 32

Summary Portfolio Capacity by Resource Type and Year, Installed MW

	Installed Capacity, MW																				
Resource	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**Total**
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-	1,240
DSM - Energy Efficiency	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426	4,953
DSM - Demand Response	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-	929
Renewable - Wind	-	194	1,937	-	100	300	-	-	-	6,165	1,755	-	-	-	-	-	-	-	-	-	10,451
Renewable - Utility Solar	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-	7,855
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	754	2,929	824	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	(196)	7,710
Renewable - Battery (Long Duration)	-	-	600	-	-	-	-	-	-	-	150	-	(600)	-	200	-	-	-	-	-	350
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-	1,500
Front Office - Selected Markets	940	1,000	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	147
Front Office Transactions - Winter	1,640	1,781	962	448	625	533	636	592	610	52	41	52	52	52	52	52	52	64	47	86	421
Front Office Transactions - Summer	1,683	1,874	1,405	1,522	1,506	570	603	608	631	143	47	18	18	20	30	38	113	134	141	193	565
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-	(1,141)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-	(2,335)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	-	-	-	(699)	-	-	-	-	-	-	-	-	-	-	-	-	(1,770)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	-	-	(356)	-	-	(247)	(237)	-	-	-	-	(593)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,682**	**5,086**	**8,538**	**7,695**	**3,885**	**5,257**	**2,523**	**2,435**	**1,928**	**7,526**	**1,169**	**199**	**(361)**	**694**	**748**	**(1,177)**	**354**	**(212)**	**327**	**509**	

P03-Hunter3-SCR

Summary Portfolio Capacity by Resource Type and Year, Installed MW

Resource	Installed Capacity, MW																				Total
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-	1,240
DSM - Energy Efficiency	123	220	259	198	216	220	240	258	637	105	149	170	161	288	586	163	186	176	143	429	4,927
DSM - Demand Response	72	53	167	105	111	90	31	13	35	-	-	2	-	-	-	225	19	38	-	-	961
Renewable - Wind	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-	9,113
Renewable - Utility Solar	-	-	1,469	2,524	483	1,832	200	-	-	972	-	300	-	-	-	-	-	-	-	-	7,780
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-	7,910
Renewable - Battery (Long Duration)	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-	350
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-	1,500
Front Office - Selected Markets	1,000	1,000	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	150
Front Office Transactions - Winter	1,640	1,778	1,025	552	552	528	172	197	237	52	41	52	52	52	52	52	52	65	47	98	365
Front Office Transactions - Summer	1,683	1,872	1,629	1,524	1,535	586	554	547	587	165	88	57	66	65	48	120	132	186	235	257	597
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-	(1,141)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	(418)	(1,178)	-	-	-	-	-	-	(268)	-	-	(1,864)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	-	-	-	(699)	-	-	-	-	-	-	-	-	-	-	-	-	(1,770)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	-	-	(356)	-	-	(247)	(237)	-	-	-	-	(593)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,742**	**5,095**	**8,440**	**7,798**	**3,625**	**5,203**	**3,918**	**1,973**	**1,496**	**4,159**	**1,259**	**225**	**279**	**750**	**1,298**	**(1,090)**	**389**	**(133)**	**425**	**784**	

P06-No Forward Tech

Summary Portfolio Capacity by Resource Type and Year, Installed MW

	Installed Capacity, MW																				
Resource	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**Total**
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-	1,240
DSM - Energy Efficiency	123	220	259	208	228	219	240	260	638	106	161	171	161	288	542	163	184	176	141	429	4,917
DSM - Demand Response	72	220	199	12	75	68	43	9	47	-	-	2	76	-	-	123	20	39	-	-	1,005
Renewable - Wind	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-	9,113
Renewable - Utility Solar	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	600	-	-	-	-	-	8,455
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	954	2,929	628	1,900	1,149	-	-	200	350	-	-	-	200	-	-	-	-	-	8,310
Renewable - Battery (Long Duration)	-	-	-	-	-	-	-	-	-	300	450	-	-	-	200	-	-	-	-	-	950
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Front Office - Selected Markets	903	1,000	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	145
Front Office Transactions - Winter	1,640	1,752	964	551	556	523	165	279	268	65	52	52	52	52	52	52	57	326	365	358	409
Front Office Transactions - Summer	1,683	1,850	1,561	1,521	1,534	585	547	585	595	362	200	191	196	215	173	222	293	408	480	503	685
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-	(1,141)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-	(2,335)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	-	-	-	(699)	-	-	-	-	-	-	-	-	-	-	-	-	(1,770)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	-	-	(356)	-	-	(247)	(237)	-	-	-	-	(593)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,645**	**5,214**	**8,343**	**7,711**	**3,604**	**5,249**	**3,916**	**1,591**	**1,548**	**4,370**	**923**	**360**	**485**	**900**	**1,979**	**(1,090)**	**554**	**351**	**986**	**1,290**	

P05-No NUC

Summary Portfolio Capacity by Resource Type and Year, Installed MW

	Installed Capacity, MW																				
Resource	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**Total**
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	895	-	303	303	-	-	345	289	-	-	-	-	-	2,135
DSM - Energy Efficiency	123	220	259	208	228	219	240	260	638	106	161	171	161	288	542	163	184	176	141	429	4,917
DSM - Demand Response	72	220	199	12	75	68	43	9	47	-	-	2	76	-	-	123	20	39	-	-	1,005
Renewable - Wind	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-	9,113
Renewable - Utility Solar	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-	7,855
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	954	2,929	628	1,900	1,149	-	-	200	350	-	-	-	200	-	-	-	-	-	8,310
Renewable - Battery (Long Duration)	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-	350
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Front Office - Selected Markets	963	1,000	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	148
Front Office Transactions - Winter	1,640	1,752	964	551	556	523	165	279	267	64	52	52	52	52	52	55	106	348	384	412	416
Front Office Transactions - Summer	1,683	1,850	1,561	1,521	1,534	585	547	583	595	362	200	191	196	215	217	270	370	461	493	582	701
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-	(1,141)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-	(2,335)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	-	-	-	(699)	-	-	-	-	-	-	-	-	-	-	-	-	(1,770)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	-	-	(356)	-	-	(247)	(237)	-	-	-	-	(593)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,705**	**5,214**	**8,343**	**7,711**	**3,604**	**5,249**	**3,916**	**1,878**	**1,547**	**4,372**	**926**	**360**	**485**	**900**	**1,423**	**(1,039)**	**680**	**426**	**1,018**	**1,423**	

P04-Huntington RET28

Summary Portfolio Capacity by Resource Type and Year, Installed MW

	Installed Capacity, MW																				
Resource	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**Total**
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-	1,240
DSM - Energy Efficiency	123	220	259	208	228	219	240	258	637	109	161	171	161	288	542	163	184	176	141	428	4,916
DSM - Demand Response	72	220	199	12	77	64	43	9	11	-	-	2	108	-	-	125	20	39	-	-	1,001
Renewable - Wind	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-	9,113
Renewable - Utility Solar	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-	7,855
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	954	2,929	628	2,300	1,149	-	-	-	-	-	-	-	100	-	-	-	-	-	8,060
Renewable - Battery (Long Duration)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	200
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-	1,500
Front Office - Selected Markets	1,000	1,000	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	150
Front Office Transactions - Winter	1,640	1,752	964	551	556	509	163	195	233	52	41	52	52	52	52	52	52	65	47	95	359
Front Office Transactions - Summer	1,683	1,850	1,561	1,521	1,533	586	546	532	587	156	78	51	64	62	48	120	132	177	231	248	588
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-	(1,141)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	(459)	-	-	-	(418)	(1,190)	-	-	-	-	-	-	(268)	-	-	(2,335)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	-	-	-	(699)	-	-	-	-	-	-	-	-	-	-	-	-	(1,770)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	-	-	(356)	-	-	(247)	(237)	-	-	-	-	(593)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,742**	**5,214**	**8,343**	**7,711**	**3,605**	**5,173**	**3,913**	**1,952**	**1,468**	**4,154**	**949**	**220**	**385**	**747**	**1,154**	**(1,190)**	**388**	**(141)**	**419**	**771**	

P02-JB3-4 EOL

Summary Portfolio Capacity by Resource Type and Year, Installed MW

	Installed Capacity, MW																				
Resource	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**Total**
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-	1,240
DSM - Energy Efficiency	123	220	259	208	228	219	241	259	637	116	163	172	163	288	542	163	183	175	141	428	4,928
DSM - Demand Response	72	220	193	6	83	61	41	10	8	-	-	-	117	-	-	121	21	20	-	-	973
Renewable - Wind	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-	9,113
Renewable - Utility Solar	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-	7,855
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-	7,910
Renewable - Battery (Long Duration)	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-	350
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-	1,500
Front Office - Selected Markets	1,000	1,000	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	150
Front Office Transactions - Winter	1,640	1,752	969	551	555	523	164	195	233	52	41	52	52	52	52	52	52	65	47	92	360
Front Office Transactions - Summer	1,683	1,850	1,561	1,521	1,533	585	546	532	587	155	78	52	65	65	48	120	132	179	231	247	589
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	(699)	-	(330)	-	-	(1,840)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-	(2,335)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	-	-	-	-	-	-	-	-	-	-	(370)	(713)	-	-	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,070)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	-	-	(356)	-	-	(247)	(237)	-	-	-	-	(593)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,742**	**5,214**	**8,342**	**7,705**	**3,610**	**5,242**	**3,913**	**1,954**	**1,465**	**4,160**	**792**	**220**	**397**	**750**	**1,254**	**(1,194)**	**388**	**(159)**	**419**	**767**	

P19-Cluster West

Summary Portfolio Capacity by Resource Type and Year, Installed MW

	Installed Capacity, MW																				
Resource	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**Total**
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-	1,240
DSM - Energy Efficiency	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426	4,953
DSM - Demand Response	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-	929
Renewable - Wind	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-	9,113
Renewable - Utility Solar	-	-	1,469	2,524	483	2,406	200	-	-	972	-	300	-	-	-	-	-	-	-	-	8,354
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	954	2,929	628	2,399	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-	8,409
Renewable - Battery (Long Duration)	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-	350
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-	1,500
Front Office - Selected Markets	1,000	1,000	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	150
Front Office Transactions - Winter	1,640	1,781	1,035	553	553	483	152	184	213	52	41	52	52	52	52	52	52	52	46	65	358
Front Office Transactions - Summer	1,683	1,874	1,637	1,525	1,535	567	476	419	539	150	50	46	50	50	30	45	121	146	189	193	566
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-	(1,141)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-	(2,335)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	-	-	-	(699)	-	-	-	-	-	-	-	-	-	-	-	-	(1,770)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	-	-	(356)	-	-	(247)	(237)	-	-	-	-	(593)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,742**	**5,086**	**8,443**	**7,803**	**3,646**	**6,202**	**3,812**	**1,838**	**1,439**	**4,151**	**776**	**227**	**271**	**724**	**1,288**	**(1,170)**	**362**	**(212)**	**374**	**684**	

P18-Cluster East

Summary Portfolio Capacity by Resource Type and Year, Installed MW

Resource	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	Total
	Installed Capacity, MW																				
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-	1,240
DSM - Energy Efficiency	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426	4,953
DSM - Demand Response	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-	929
Renewable - Wind	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-	9,113
Renewable - Utility Solar	-	-	1,469	2,524	483	1,907	2,373	-	-	972	-	300	-	-	-	-	-	-	-	-	10,028
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	954	2,929	628	1,900	3,322	-	-	-	150	-	-	-	200	-	-	-	-	-	10,083
Renewable - Battery (Long Duration)	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-	350
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-	1,500
Front Office - Selected Markets	1,000	1,000	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	150
Front Office Transactions - Winter	1,640	1,781	1,035	553	553	524	66	84	128	52	41	51	41	41	52	52	52	52	29	27	343
Front Office Transactions - Summer	1,683	1,874	1,637	1,525	1,535	586	303	328	374	58	18	16	-	-	-	3	14	30	40	36	503
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-	(1,141)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-	(2,335)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	-	-	-	(699)	-	-	-	-	-	-	-	-	-	-	-	-	(1,770)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	-	-	(356)	-	-	(247)	(237)	-	-	-	-	(593)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,742**	**5,086**	**8,443**	**7,803**	**3,646**	**5,264**	**7,899**	**1,647**	**1,189**	**4,059**	**744**	**196**	**210**	**663**	**1,258**	**(1,212)**	**255**	**(328)**	**208**	**489**	

P01-JB3-4 GC

Summary Portfolio Capacity by Resource Type and Year, Installed MW

Resource	Installed Capacity, MW																				
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	Total
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-	1,240
DSM - Energy Efficiency	123	220	259	208	228	219	240	258	637	115	161	171	161	288	542	163	184	176	141	428	4,922
DSM - Demand Response	72	220	199	12	77	64	43	9	11	-	-	2	108	-	-	125	20	39	-	-	1,001
Renewable - Wind	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-	9,113
Renewable - Utility Solar	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-	7,855
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-	7,910
Renewable - Battery (Long Duration)	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-	350
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-	1,500
Front Office - Selected Markets	987	1,000	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	149
Front Office Transactions - Winter	1,640	1,752	964	551	555	523	164	195	233	52	41	52	52	52	52	52	52	65	47	94	359
Front Office Transactions - Summer	1,683	1,850	1,561	1,521	1,533	585	546	532	587	156	78	52	66	65	48	120	132	179	231	247	589
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-	(1,141)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-	(2,335)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	1,069	-	-	-	-	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(1,056)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,770)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	-	-	(356)	-	-	(247)	(237)	-	-	-	-	(593)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,729**	**5,214**	**8,343**	**7,711**	**3,604**	**5,245**	**3,914**	**1,952**	**1,468**	**4,160**	**790**	**221**	**387**	**750**	**1,254**	**(1,190)**	**388**	**(139)**	**419**	**769**	

P-MM

Summary Portfolio Capacity by Resource Type and Year, Installed MW																					
	Installed Capacity, MW																				
Resource	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	Total
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-	1,240
DSM - Energy Efficiency	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426	4,953
DSM - Demand Response	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-	929
Renewable - Wind	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-	9,113
Renewable - Utility Solar	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-	7,855
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-	7,910
Renewable - Battery (Long Duration)	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-	350
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-	1,500
Front Office - Selected Markets	987	1,000	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	149
Front Office Transactions - Winter	1,640	1,781	1,035	553	553	524	166	195	231	52	41	52	52	52	52	52	52	62	46	85	364
Front Office Transactions - Summer	1,683	1,874	1,637	1,525	1,535	586	547	535	587	158	83	53	66	65	48	120	132	182	231	252	595
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-	(1,141)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-	(2,335)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	-	-	-	(699)	-	-	-	-	-	-	-	-	-	-	-	-	(1,770)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	-	-	(356)	-	-	(247)	(237)	-	-	-	-	(593)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,729**	**5,086**	**8,443**	**7,803**	**3,646**	**5,264**	**3,897**	**1,965**	**1,505**	**4,159**	**809**	**234**	**287**	**739**	**1,306**	**(1,095)**	**373**	**(166)**	**416**	**763**	

W-11 CETA Max Benefit

Summary Portfolio Capacity by Resource Type and Year, Installed MW																					
	Installed Capacity, MW																				
Resource	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	Total
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	-	-	606	-	-	-	-	634	-	-	-	-	-	1,240
DSM - Energy Efficiency	123	220	259	206	225	230	245	265	637	114	160	170	162	288	586	165	170	165	158	429	4,977
DSM - Demand Response	72	39	154	107	123	75	27	-	46	-	-	-	3	-	-	246	19	19	-	-	930
Renewable - Wind	-	194	1,717	-	100	457	500	-	-	4,788	3,607	-	-	-	-	-	-	-	-	-	11,363
Renewable - Utility Solar	-	-	1,469	1,600	483	2,589	1,298	120	108	600	-	841	-	-	-	-	-	-	-	-	9,108
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	954	1,600	628	1,979	1,647	400	-	600	-	-	-	-	1,207	-	-	-	-	-	9,015
Renewable - Battery (Long Duration)	-	-	-	-	-	400	-	-	-	-	-	-	-	-	784	-	-	-	-	-	1,184
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	27	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	500	-	-	500	500	-	-	-	-	-	-	-	-	1,500
Front Office - Selected Markets	1,000	1,000	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	150
Front Office Transactions - Winter	1,572	1,745	1,342	776	704	441	305	384	520	200	46	31	31	31	31	38	38	59	24	39	418
Front Office Transactions - Summer	1,656	1,869	1,608	1,691	1,717	607	541	546	583	184	26	3	3	3	3	3	3	3	3	3	553
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	(699)	-	-	-	-	-	-	-	(330)	-	-	(1,840)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	(2,067)	-	-	-	-	-	-	-	(268)	-	-	(2,335)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	-	-	-	-	-	-	-	-	-	-	(370)	(713)	-	-	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,070)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	(119)	-	(237)	-	-	(247)	(237)	-	-	(64)	-	(657)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	4,647	5,045	8,503	5,938	3,988	6,525	4,235	2,067	1,894	4,207	4,339	1,308	199	322	2,628	(498)	230	(352)	121	471	

W-11 CETA No Climate

Summary Portfolio Capacity by Resource Type and Year, Installed MW	Installed Capacity, MW																				
Resource	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**Total**
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	-	-	606	-	-	-	-	634	-	-	-	-	-	1,240
DSM - Energy Efficiency	123	220	259	206	225	230	245	265	637	114	160	170	162	288	586	165	170	165	158	429	4,977
DSM - Demand Response	72	39	154	107	123	75	27	-	46	-	-	-	3	-	-	246	19	19	-	-	930
Renewable - Wind	-	194	1,717	-	-	457	500	-	-	6,486	3,607	-	-	-	-	-	-	-	-	-	12,961
Renewable - Utility Solar	-	-	1,469	1,600	-	2,589	1,298	120	108	600	-	841	-	-	-	-	-	-	-	-	8,625
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	954	1,600	-	1,979	1,647	-	-	600	-	-	-	-	1,207	-	-	-	-	-	7,987
Renewable - Battery (Long Duration)	-	-	-	-	-	400	-	-	-	-	-	-	-	-	784	-	-	-	-	-	1,184
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	27	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	500	-	-	500	500	-	-	-	-	-	-	-	-	1,500
Front Office - Selected Markets	1,000	997	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	150
Front Office Transactions - Winter	1,639	1,813	1,518	942	1,071	624	508	554	672	185	15	16	16	16	-	7	7	15	53	51	486
Front Office Transactions - Summer	1,623	1,821	1,652	1,711	1,818	622	544	559	591	66	-	-	-	-	-	-	-	-	-	-	550
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	(699)	-	-	-	-	-	-	-	(330)	-	-	(1,840)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	(2,067)	-	-	-	-	-	-	-	(268)	-	-	(2,335)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	-	-	-	-	-	-	-	-	-	-	(370)	(713)	-	-	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,070)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	(119)	-	(237)	-	-	(247)	(237)	-	-	(64)	-	(657)
Retire - Non-Thermal	(21)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(21)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,683**	**5,062**	**8,723**	**6,124**	**3,245**	**6,723**	**4,441**	**1,850**	**2,054**	**5,772**	**4,282**	**1,290**	**181**	**304**	**2,594**	**(532)**	**196**	**(399)**	**147**	**480**	

P12-RET Coal 30 NG 40

Summary Portfolio Capacity by Resource Type and Year, Installed MW																					
	Installed Capacity, MW																				
Resource	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	Total
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	606	-	-	-	-	-	345	1,790	-	-	-	-	-	2,741
DSM - Energy Efficiency	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426	4,953
DSM - Demand Response	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-	929
Renewable - Wind	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	676	-	-	-	-	-	9,249
Renewable - Utility Solar	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-	7,855
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	754	2,929	628	1,900	1,149	-	-	-	150	-	-	-	1,323	-	-	-	-	-	8,833
Renewable - Battery (Long Duration)	-	-	600	-	-	-	-	-	-	-	150	-	(600)	-	200	-	-	-	-	-	350
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	500
Front Office - Selected Markets	998	1,000	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	150
Front Office Transactions - Winter	1,640	1,781	962	448	691	531	216	290	298	79	65	62	65	65	719	742	805	1,069	1,085	1,100	636
Front Office Transactions - Summer	1,683	1,874	1,405	1,515	1,501	566	547	529	570	273	182	181	191	191	577	597	599	652	664	664	748
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	-	-	-	(811)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	(450)	-	-	-	-	(418)	(1,199)	-	-	-	-	-	-	-	-	-	(2,067)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	598	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	(598)	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	(598)	-	-	(699)	-	-	-	-	-	-	-	-	-	-	-	-	(2,368)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	-	-	(356)	-	-	(2,781)	-	-	-	-	-	(2,890)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,740**	**5,086**	**8,538**	**7,688**	**3,300**	**5,251**	**3,947**	**2,054**	**1,555**	**3,801**	**882**	**372**	**(175)**	**878**	**2,728**	**309**	**1,593**	**1,311**	**1,888**	**2,190**	

Table 9.1 – Non-Emitting Peaking (Installed Capacity MW)[1]

Study	Installed Capacity, MW																			
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
P-LN	-	-	-	-	-	-	-	-	-	303	-	-	-	-	1,240	-	-	-	-	-
P-MN		-	-	-	-	-	-	-	-	-	-	-	303	578	345	-	-	-	-	-
P-MM	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P-HH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	951	-	-	-	-	-
P-SC	-	-	-	-	-	-	-	-	-	606	-	-	-	-	634	-	-	-	-	-
P01-JB3-4 GC	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P02-JB3-4 EOL	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P03-Hunter3-SCR	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P04-Huntington RET28	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P05-No NUC	-	-	-	-	-	-	-	895	-	303	303	-	-	345	289	-	-	-	-	-
P06-No Forward Tech	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P07-D3-D2 32	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P08-No D3-D2	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P09-No WY OTR	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P10-Offshore Wind	-	-	-	-	-	-	-	606	-	-	-	-	-	-	289	-	-	-	-	-
P11-Max NG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P12-RET Coal 30 NG 40	-	-	-	-	-	-	-	606	-	-	-	-	-	345	1,790	-	-	-	-	-
P13-All EE	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P14-All GW	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P15-No GWS	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P16-No B2H	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P17-Col3-4 RET25	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P18-Cluster East	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P19-Cluster West	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P20-JB3-4 CCUS	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-

1 – Positive values indicate installed capacity in the first full year of operations

Table 9.2 - DSM Energy Efficiency (Installed Capacity MW)

Study	Installed Capacity, MW																			
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
P-LN	123	220	259	197	216	219	240	258	637	103	160	170	161	281	586	163	170	165	139	412
P-MN	123	220	259	198	217	221	243	259	637	105	160	170	161	288	586	164	170	165	139	412
P-MM	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P-HH	123	220	259	210	229	234	255	266	675	116	161	185	162	289	594	165	187	176	172	671
P-SC	123	220	259	206	225	230	245	265	637	114	160	170	162	288	586	165	170	165	158	429
P01-JB3-4 GC	123	220	259	208	228	219	241	259	637	116	163	172	163	288	542	163	183	175	141	428
P02-JB3-4 EOL	123	220	259	208	228	219	240	258	637	115	161	171	161	288	542	163	184	176	141	428
P03-Hunter3-SCR	123	220	259	198	216	220	240	258	637	105	149	170	161	288	586	163	186	176	143	429
P04-Huntington RET28	123	220	259	208	228	219	240	258	637	109	161	171	161	288	542	163	184	176	141	428
P05-No NUC	123	220	259	208	228	219	240	260	638	106	161	171	161	288	542	163	184	176	141	429
P06-No Forward Tech	123	220	259	208	228	219	240	260	638	106	161	171	161	288	542	163	184	176	141	429
P07-D3-D2 32	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P08-No D3-D2	123	220	259	198	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P09-No WY OTR	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P10-Offshore Wind	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P11-Max NG	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P12-RET Coal 30 NG 40	123	954	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P13-All EE	123	220	259	289	330	334	392	457	1,016	215	301	283	292	457	816	230	253	241	343	1,231
P14-All GW	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P15-No GWS	123	220	259	198	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P16-No B2H	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P17-Col3-4 RET25	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P18-Cluster East	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P19-Cluster West	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P20-JB3-4 CCUS	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426

Table 9.3 – DSM Demand Response (Installed Capacity MW)

Study	Installed Capacity, MW																			
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
P-LN	72	39	143	38	161	120	33	16	33	-	-	-	51	-	-	170	19	19	-	-
P-MN	72	39	152	99	126	94	27	13	35	-	-	-	-	-	1	228	19	19	-	-
P-MM	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P-HH	72	39	154	119	117	81	26	-	37	5	13	12	26	-	-	239	22	19	-	-
P-SC	72	39	154	107	123	75	27	-	46	-	-	-	3	-	-	246	19	19	-	-
P01-JB3-4 GC	72	220	193	6	83	61	41	10	8	-	-	-	117	-	-	121	21	20	-	-
P02-JB3-4 EOL	72	220	199	12	77	64	43	9	11	-	-	2	108	-	-	125	20	39	-	-
P03-Hunter3-SCR	72	53	167	105	111	90	31	13	35	-	-	2	-	-	-	225	19	38	-	-
P04-Huntington RET28	72	220	199	12	77	64	43	9	11	-	-	2	108	-	-	125	20	39	-	-
P05-No NUC	72	220	199	12	75	68	43	9	47	-	-	2	76	-	-	123	20	39	-	-
P06-No Forward Tech	72	220	199	12	75	68	43	9	47	-	-	2	76	-	-	123	20	39	-	-
P07-D3-D2 32	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P08-No D3-D2	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P09-No WY OTR	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P10-Offshore Wind	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P11-Max NG	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P12-RET Coal 30 NG 40	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P13-All EE	72	39	152	109	119	91	29	13	35	-	1	-	2	-	4	265	70	20	-	778
P14-All GW	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P15-No GWS	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P16-No B2H	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P17-Col3-4 RET25	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P18-Cluster East	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P19-Cluster West	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P20-JB3-4 CCUS	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-

Table 9.4 – Renewable Wind (Installed Capacity MW)[1]

Study	Installed Capacity, MW																			
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
P-LN	-	194	1,717	-	-	-	500	-	11	5,477	1,821	-	-	-	-	-	-	-	-	-
P-MN	-	194	1,717	-	-	-	500	-	-	6,025	3,565	-	450	-	-	-	-	-	-	-
P-MM	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P-HH	-	194	1,717	-	-	174	500	-	-	7,922	2,321	-	-	-	-	-	-	-	-	-
P-SC	-	194	1,717	-	-	457	500	-	-	6,486	3,607	-	-	-	-	-	-	-	-	-
P01-JB3-4 GC	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P02-JB3-4 EOL	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P03-Hunter3-SCR	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P04-Huntington RET28	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P05-No NUC	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P06-No Forward Tech	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P07-D3-D2 32	-	194	1,937	-	100	300	-	-	-	6,165	1,755	-	-	-	-	-	-	-	-	-
P08-No D3-D2	-	194	1,937	-	100	300	-	-	-	2,349	1,282	-	-	-	-	-	-	-	-	-
P09-No WY OTR	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P10-Offshore Wind	-	194	1,937	-	100	300	1,900	-	-	2,683	1,459	-	-	-	540	-	-	-	-	-
P11-Max NG	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P12-RET Coal 30 NG 40	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	676	-	-	-	-	-
P13-All EE	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P14-All GW	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P15-No GWS	-	194	296	-	100	300	-	-	-	2,349	1,282	-	-	-	-	-	-	-	-	-
P16-No B2H	-	194	1,937	-	100	-	1,900	400	-	2,783	959	-	-	-	540	-	-	-	-	-
P17-Col3-4 RET25	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P18-Cluster East	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P19-Cluster West	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P20-JB3-4 CCUS	-	194	1,937	-	100	300	1,900	-	-	2,733	1,359	-	-	-	540	-	-	-	-	-

1 – Positive values indicate installed capacity in the first full year of operations

Table 9.5 – Renewable Solar (Installed Capacity MW)[1]

Study	Installed Capacity, MW																			
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
P-LN	-	-	1,469	1,600	-	2,519	1,298	-	288	241	-	-	-	-	1,400	-	-	-	-	-
P-MN	-	-	1,469	1,600	-	2,470	1,298	-	254	941	-	-	-	-	600	-	-	-	-	-
P-MM	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P-HH	-	-	1,469	1,600	-	3,006	1,298	-	4	1,288	241	-	-	-	-	-	-	-	-	-
P-SC	-	-	1,469	1,600	-	2,589	1,298	-	108	600	-	841	-	-	-	-	-	-	-	-
P01-JB3-4 GC	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P02-JB3-4 EOL	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P03-Hunter3-SCR	-	-	1,469	2,524	483	1,832	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P04-Huntington RET28	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P05-No NUC	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P06-No Forward Tech	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	600	-	-	-	-	-
P07-D3-D2 32	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P08-No D3-D2	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P09-No WY OTR	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P10-Offshore Wind	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P11-Max NG	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P12-RET Coal 30 NG 40	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P13-All EE	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P14-All GW	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P15-No GWS	-	-	1,469	2,224	483	2,307	600	-	200	972	-	300	-	-	-	-	-	-	-	-
P16-No B2H	-	-	1,469	2,524	483	1,507	600	-	-	972	600	300	-	-	-	-	-	-	-	-
P17-Col3-4 RET25	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P18-Cluster East	-	-	1,469	2,524	483	1,907	2,373	-	-	972	-	300	-	-	-	-	-	-	-	-
P19-Cluster West	-	-	1,469	2,524	483	2,406	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P20-JB3-4 CCUS	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-

1 – Positive values indicate installed capacity in the first full year of operations

Table 9.6 – Battery Storage (Installed Capacity MW)[1]

Study	Installed Capacity, MW																			
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
P-LN	-	-	954	1,600	160	2,008	1,647	-	-	-	400	-	-	-	2,560	-	-	-	-	-
P-MN	-	-	954	1,600	-	2,304	1,647	-	-	600	-	-	-	-	2,356	-	-	-	-	-
P-MM	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-
P-HH	-	-	954	1,600	-	2,599	1,647	-	-	600	-	-	-	-	1,541	-	-	-	-	-
P-SC	-	-	954	1,600	-	1,979	1,647	-	-	600	-	-	-	-	1,207	-	-	-	-	-
P01-JB3-4 GC	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-
P02-JB3-4 EOL	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-
P03-Hunter3-SCR	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-
P04-Huntington RET28	-	-	954	2,929	628	2,300	1,149	-	-	-	-	-	-	-	100	-	-	-	-	-
P05-No NUC	-	-	954	2,929	628	1,900	1,149	-	-	200	350	-	-	-	200	-	-	-	-	-
P06-No Forward Tech	-	-	954	2,929	628	1,900	1,149	-	-	200	350	-	-	-	200	-	-	-	-	-
P07-D3-D2 32	-	-	754	2,929	824	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	(196)
P08-No D3-D2	-	-	954	2,929	628	1,900	1,149	-	-	800	150	-	-	-	200	-	-	-	-	-
P09-No WY OTR	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-
P10-Offshore Wind	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	500	-	-	-	-	-
P11-Max NG	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-
P12-RET Coal 30 NG 40	-	-	754	2,929	824	1,900	1,149	-	-	-	150	-	-	-	1,323	-	-	-	-	(196)
P13-All EE	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-
P14-All GW	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-
P15-No GWS	-	-	954	2,629	628	2,500	1,349	-	-	800	150	-	-	-	200	-	-	-	-	-
P16-No B2H	-	-	954	2,929	1,352	1,900	1,149	-	-	-	750	-	-	-	200	-	-	-	-	-
P17-Col3-4 RET25	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-
P18-Cluster East	-	-	954	2,929	628	1,900	3,322	-	-	-	150	-	-	-	200	-	-	-	-	-
P19-Cluster West	-	-	954	2,929	628	2,399	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-
P20-JB3-4 CCUS	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-

1 – Positive values indicate installed capacity in the first full year of operations

Table 9.7 – Battery, Long Duration (Installed Capacity MW)[1]

Study	Installed Capacity, MW																			
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
P-LN	-	-	-	-	-	600	-	-	-	-	-	-	-	-	200	-	-	-	-	-
P-MN	-	-	-	-	-	400	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P-MM	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P-HH	-	-	-	-	-	600	-	-	-	-	-	-	-	-	200	-	-	-	-	-
P-SC	-	-	-	-	-	400	-	-	-	-	-	-	-	-	784	-	-	-	-	-
P01-JB3-4 GC	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P02-JB3-4 EOL	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P03-Hunter3-SCR	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P04-Huntington RET28	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-
P05-No NUC	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P06-No Forward Tech	-	-	-	-	-	-	-	-	-	300	450	-	-	-	200	-	-	-	-	-
P07-D3-D2 32	-	-	600	-	-	-	-	-	-	-	150	-	(600)	-	200	-	-	-	-	-
P08-No D3-D2	-	-	-	-	-	-	-	-	-	600	150	-	-	-	200	-	-	-	-	-
P09-No WY OTR	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P10-Offshore Wind	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P11-Max NG	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P12-RET Coal 30 NG 40	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P13-All EE	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P14-All GW	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P15-No GWS	-	-	-	-	-	-	-	-	-	600	150	-	-	-	200	-	-	-	-	-
P16-No B2H	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P17-Col3-4 RET25	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P18-Cluster East	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P19-Cluster West	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P20-JB3-4 CCUS	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-

1 – Positive values indicate installed capacity in the first full year of operations

Table 9.8 – Nuclear (Installed Capacity MW)[1]

Study	Installed Capacity, MW																			
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
P-LN	-	-	-	-	-	-	-	500	-	1,000	-	-	-	-	-	-	-	-	-	-
P-MN	-	-	-	-	-	-	-	500	-	1,000	-	-	-	-	-	-	-	-	-	-
P-MM	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P-HH	-	-	-	-	-	-	-	500	-	1,000	-	-	-	-	500	-	-	-	-	-
P-SC	-	-	-	-	-	-	-	500	-	-	500	500	-	-	-	-	-	-	-	-
P01-JB3-4 GC	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P02-JB3-4 EOL	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P03-Hunter3-SCR	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P04-Huntington RET28	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P05-No NUC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P06-No Forward Tech	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P07-D3-D2 32	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P08-No D3-D2	-	-	-	-	-	-	-	500	-	500	500	-	-	-	1,000	-	-	-	-	-
P09-No WY OTR	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P10-Offshore Wind	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P11-Max NG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P12-RET Coal 30 NG 40	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-
P13-All EE	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P14-All GW	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P15-No GWS	-	-	-	-	-	-	-	500	-	500	500	-	-	-	1,000	-	-	-	-	-
P16-No B2H	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P17-Col3-4 RET25	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P18-Cluster East	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P19-Cluster West	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P20-JB3-4 CCUS	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-

1 – Positive values indicate installed capacity in the first full year of operations

Table 9.9 – Coal End-of-life Retirements[1]

Study	Installed Capacity, MW																			
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
P-LN	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	-	-	-
P-MN	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P-MM	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P-HH	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P-SC	-	-	-	(82)	-	(253)	(328)	(148)	-	(699)	-	-	-	-	-	-	-	(330)	-	-
P01-JB3-4 GC	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	(699)	-	(330)	-	-
P02-JB3-4 EOL	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P03-Hunter3-SCR	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P04-Huntington RET28	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P05-No NUC	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P06-No Forward Tech	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P07-D3-D2 32	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P08-No D3-D2	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P09-No WY OTR	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P10-Offshore Wind	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P11-Max NG	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P12-RET Coal 30 NG 40	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	-	-	-
P13-All EE	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P14-All GW	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P15-No GWS	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	(330)	-	-	-	-	-
P16-No B2H	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P17-Col3-4 RET25	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P18-Cluster East	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P19-Cluster West	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P20-JB3-4 CCUS	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-

1 – Negative values indicate retirement of coal fueled capacity

Table 9.10 – Coal with SNCR Installation[1,2]

Study	Installed Capacity, MW																			
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
P-LN	-	-	-	2,067	-	-	-	-	-	(2,067)	-	-	-	-	-	-	-	-	-	-
P-MN	-	-	-	2,335	-	-	-	-	-	(2,067)	-	-	-	-	-	-	-	(268)	-	-
P-MM	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P-HH	-	-	-	2,335	-	-	-	-	-	(2,067)	-	-	-	-	-	-	-	(268)	-	-
P-SC	-	-	-	2,335	-	-	-	-	-	(2,067)	-	-	-	-	-	-	-	(268)	-	-
P01-JB3-4 GC	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P02-JB3-4 EOL	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P03-Hunter3-SCR	-	-	-	1,864	-	-	-	-	-	(418)	(1,178)	-	-	-	-	-	-	(268)	-	-
P04-Huntington RET28	-	-	-	2,335	-	(459)	-	-	-	(418)	(1,190)	-	-	-	-	-	-	(268)	-	-
P05-No NUC	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P06-No Forward Tech	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P07-D3-D2 32	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P08-No D3-D2	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P09-No WY OTR	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P10-Offshore Wind	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P11-Max NG	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P12-RET Coal 30 NG 40	-	-	-	2,067	(450)	-	-	-	-	(418)	(1,199)	-	-	-	-	-	-	-	-	-
P13-All EE	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P14-All GW	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P15-No GWS	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	(268)	-	-	-	-	-
P16-No B2H	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P17-Col3-4 RET25	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P18-Cluster East	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P19-Cluster West	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P20-JB3-4 CCUS	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-

1 – Positive values indicate first full year of operations with SNCR installed

2 – Negative values indicate retirement of coal fueled capacity with SNCR

Table 9.11 – Coal to Natural Gas Conversions[1,2]

Study	Installed Capacity, MW																			
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
P-LN	-	713	-	370	598	-	-	699	-	(330)	-	-	-	-	(370)	(1,413)	-	(268)	-	-
P-MN	-	713	-	370	-	-	-	340	(354)	-	-	-	-	(160)	(210)	(699)	-	-	-	-
P-MM	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P-HH	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P-SC	-	713	-	370	-	-	-	-	-	-	-	-	-	-	(370)	(713)	-	-	-	-
P01-JB3-4 GC	-	713	-	370	-	-	-	-	-	-	-	-	-	-	(370)	(713)	-	-	-	-
P02-JB3-4 EOL	-	713	-	1,069	-	-	-	-	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P03-Hunter3-SCR	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P04-Huntington RET28	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P05-No NUC	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P06-No Forward Tech	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P07-D3-D2 32	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P08-No D3-D2	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P09-No WY OTR	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P10-Offshore Wind	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P11-Max NG	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P12-RET Coal 30 NG 40	-	713	-	370	598	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	(598)	-	-
P13-All EE	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P14-All GW	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P15-No GWS	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(1,783)	-	-	-	-	-
P16-No B2H	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P17-Col3-4 RET25	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P18-Cluster East	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P19-Cluster West	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P20-JB3-4 CCUS	-	713	-	370	-	-	-	349	-	-	-	-	-	-	(370)	(1,062)	-	-	-	-

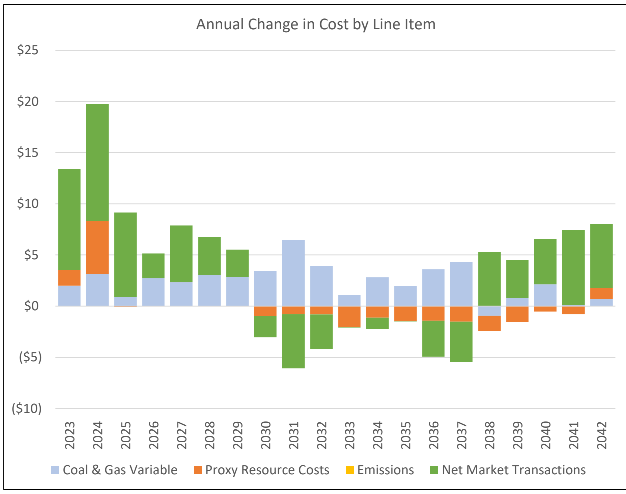
1 – Positive values indicate first full year of natural gas-fueled operation

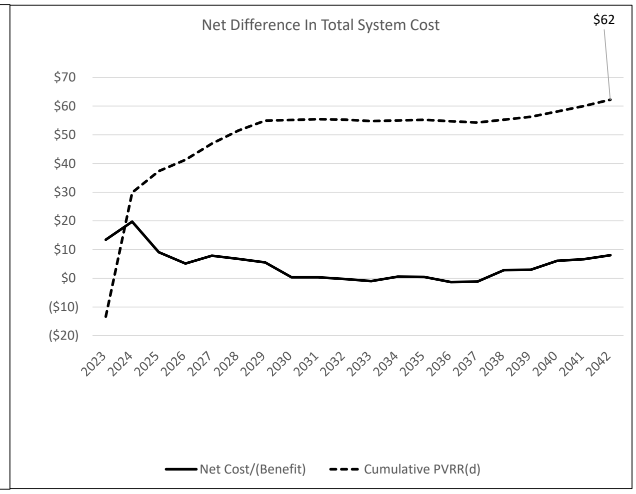
2 – Negative values indicate retirement of gas-converted capacity

APPENDIX J – STOCHASTIC SIMULATION RESULTS

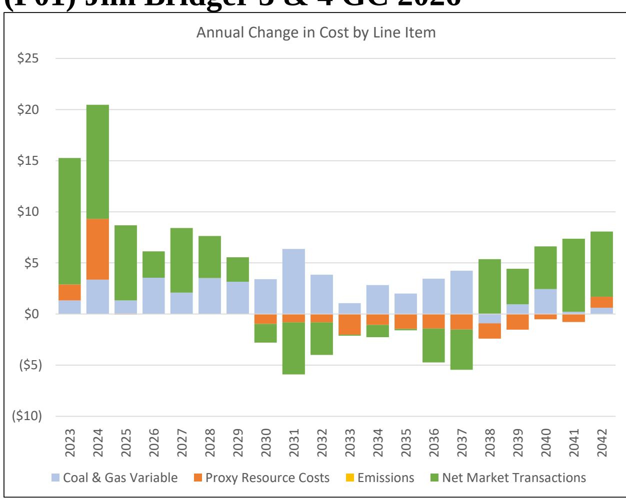
The following figures provide the cost summary detail comparing the MT model 95th percentile results to the mean results. This can indicate which cost categories pose the largest risks. Note that the 95th percentile sample is determined from the present value impact over the entire IRP study horizon, so it is not the illustrating the range of risk in each individual year.

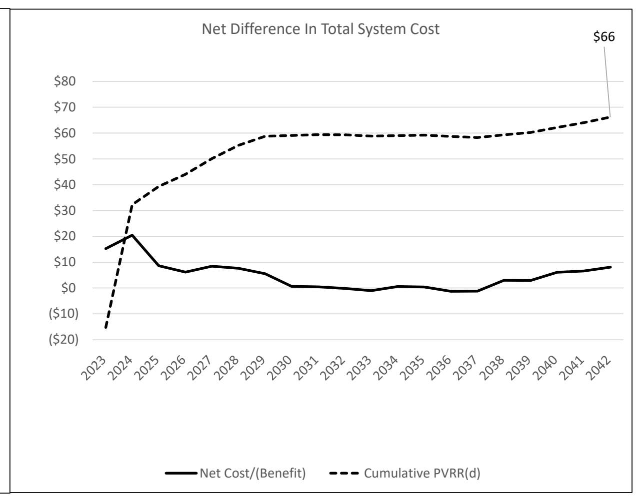
2023 IRP Preferred Portfolio



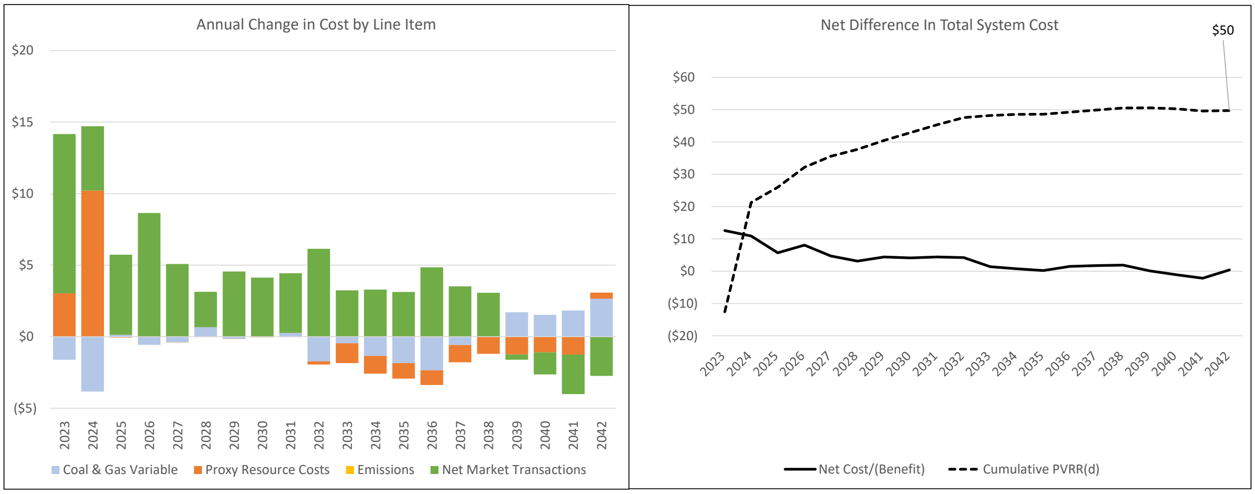


(P01) Jim Bridger 3 & 4 GC 2026

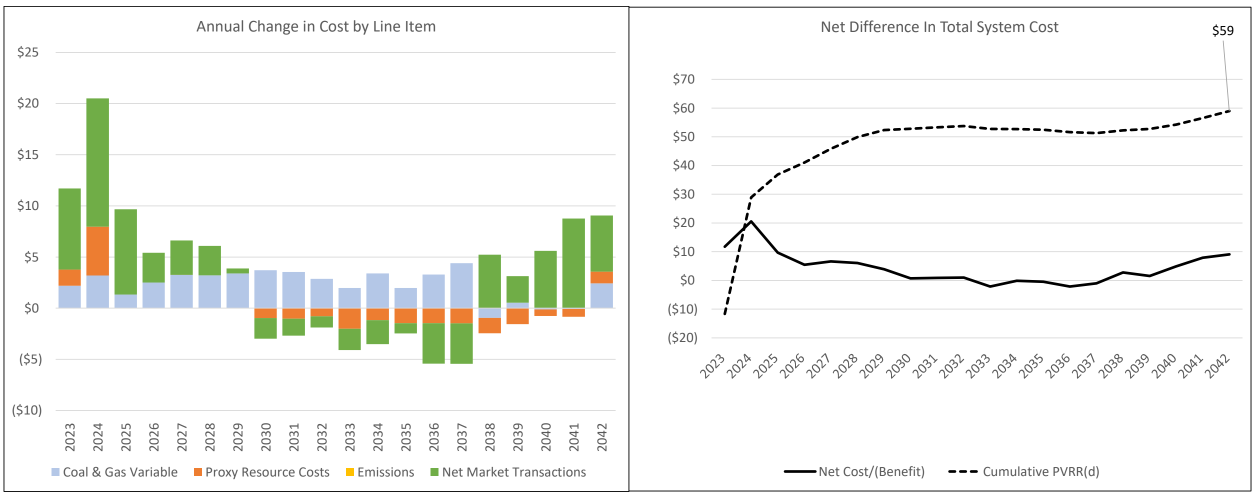




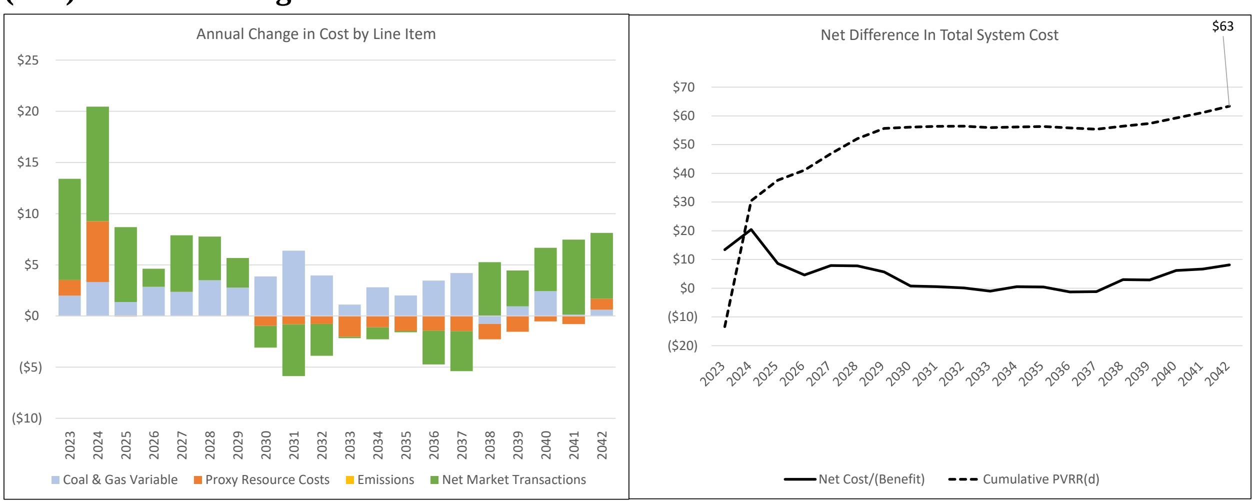
(P02) Jim Bridger 3 & 4 Coal EOL



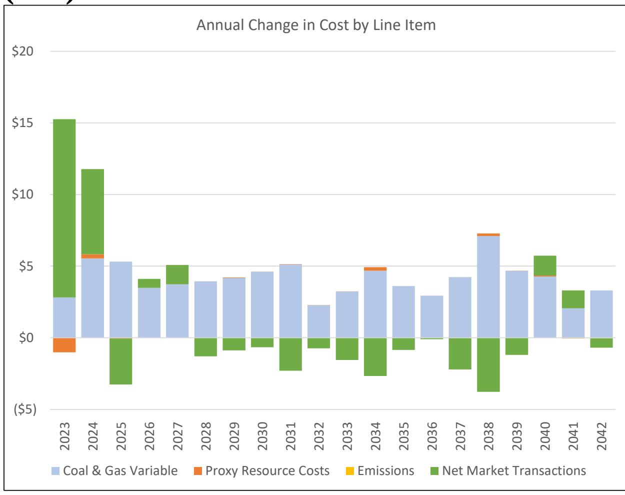
(P03) Hunter 3 SCR

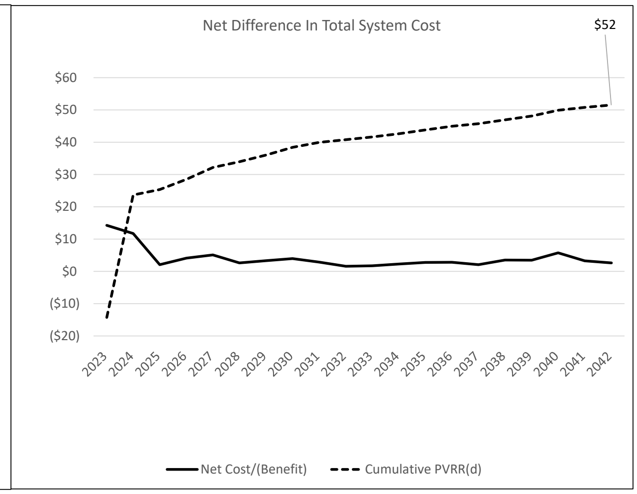


(P04) Retire Huntington 2028

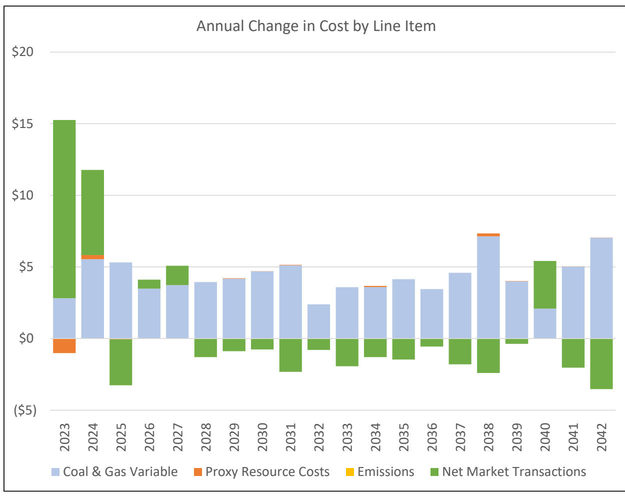


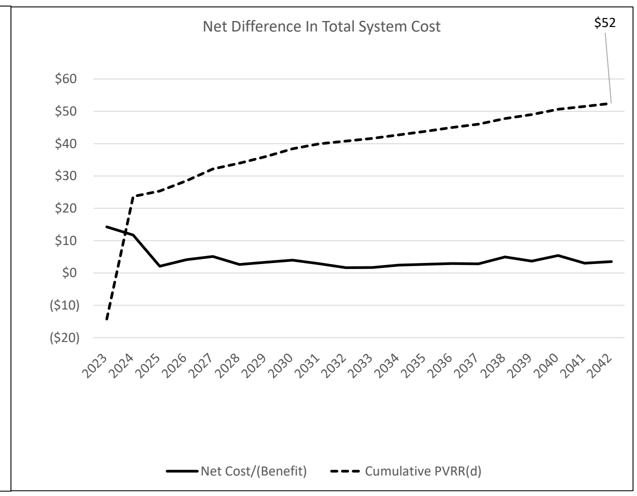
(P05) No NUC add Peaker





(P06) No NUC No Forward Tech





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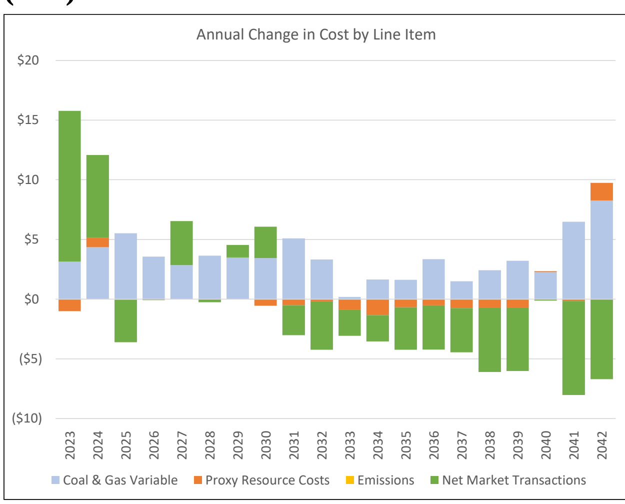

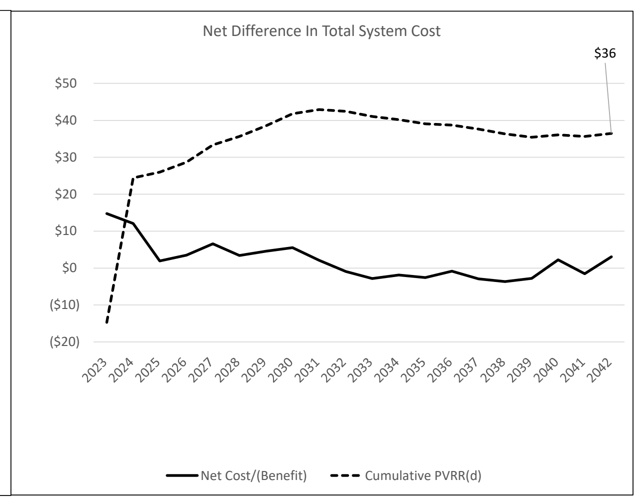

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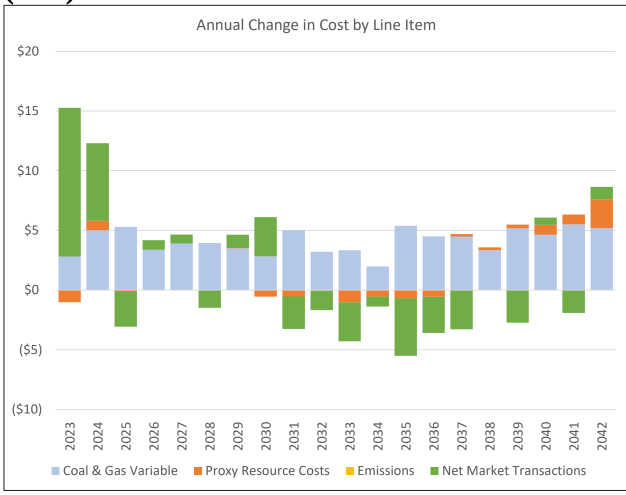

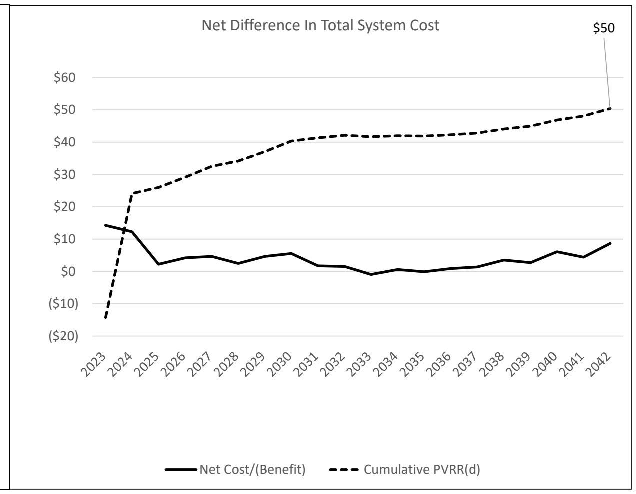

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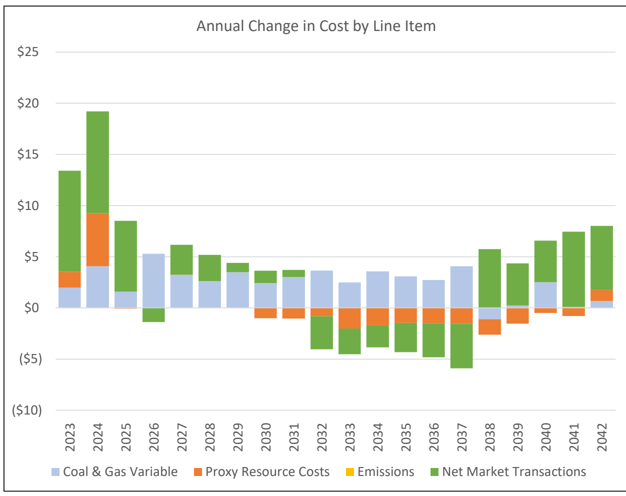

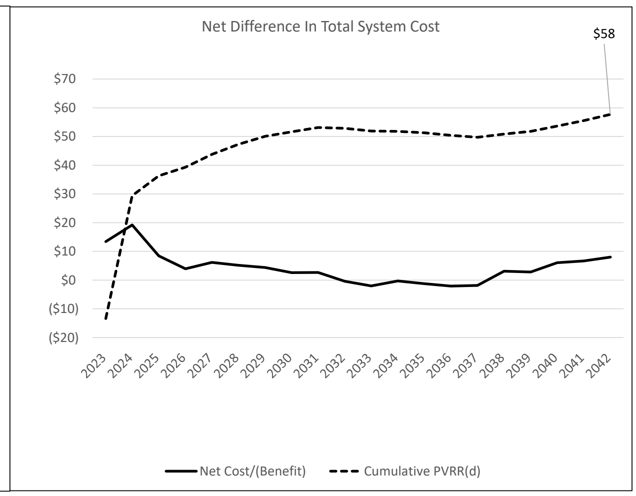

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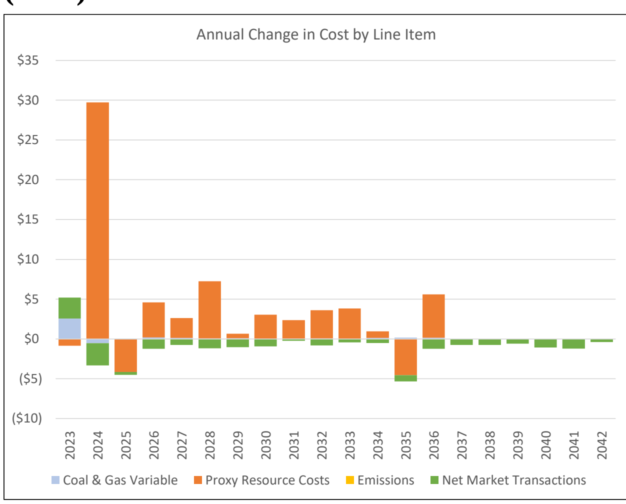

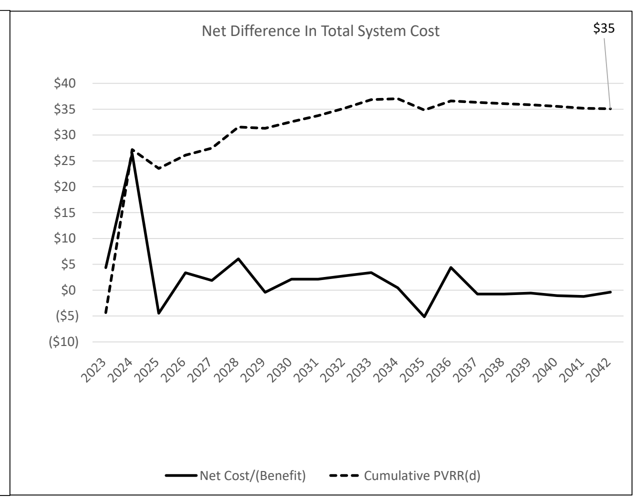

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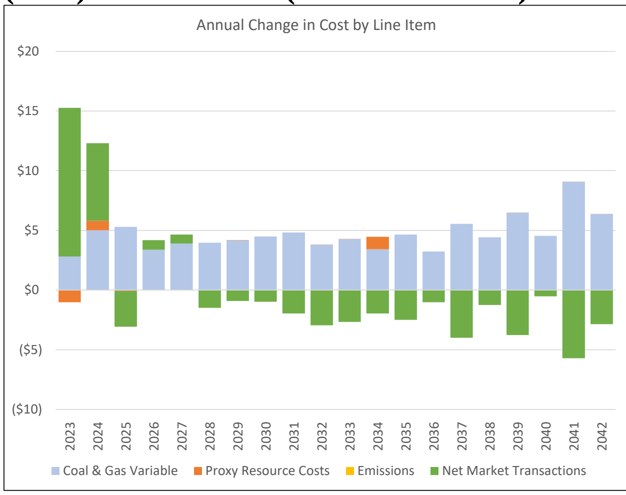

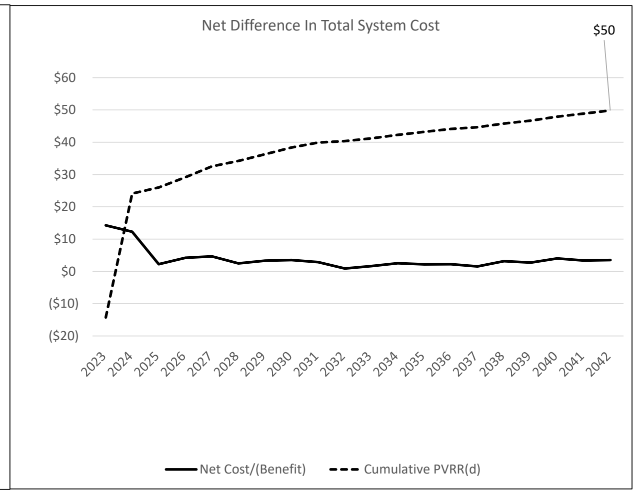

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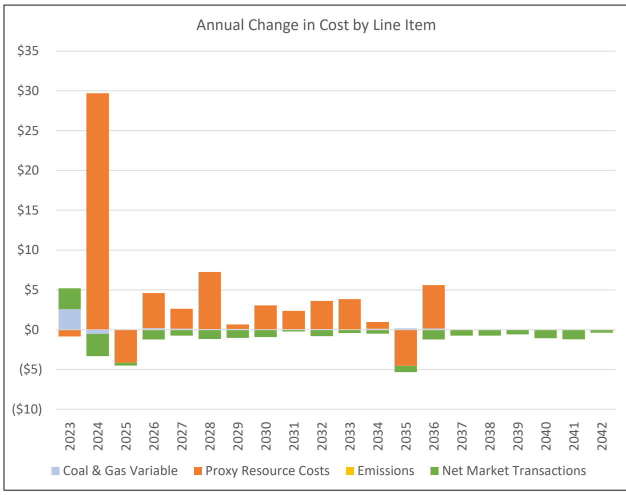
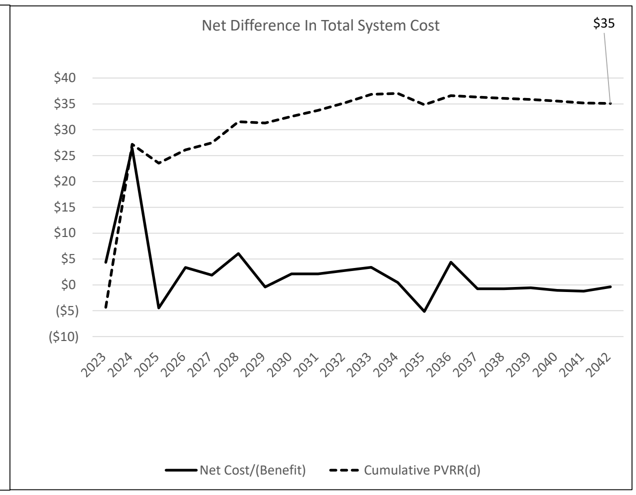
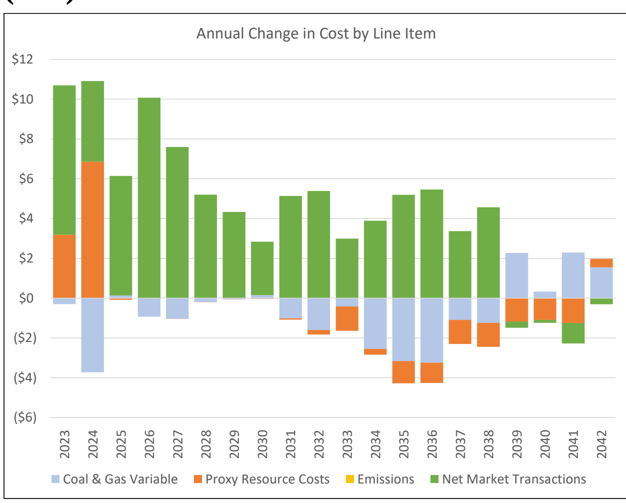
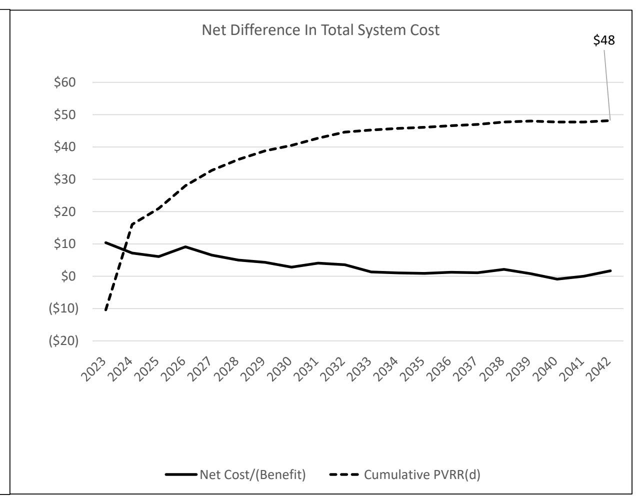


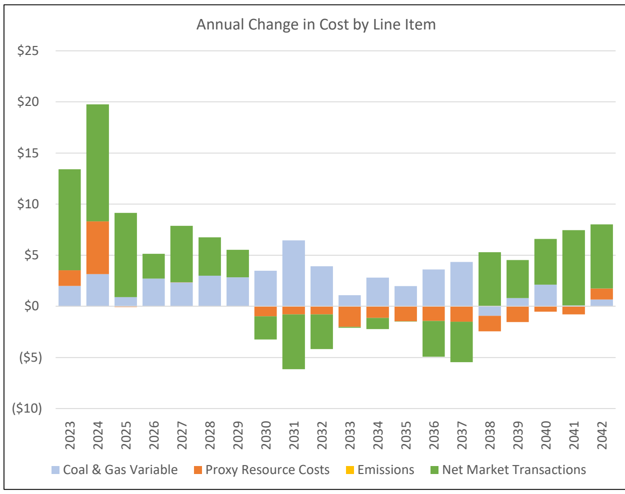


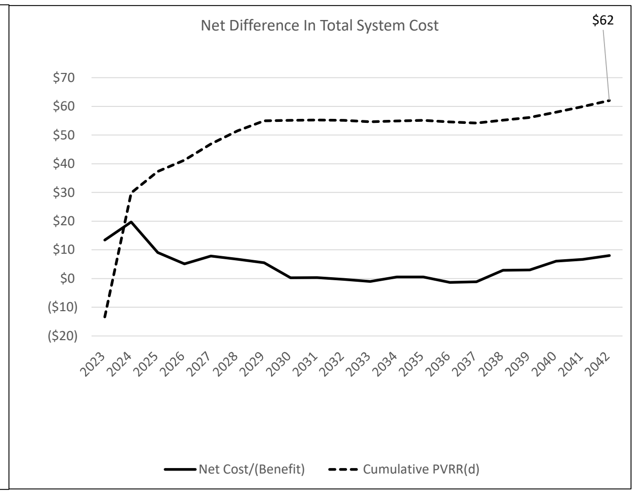
(P13) - ALL EE





(P14) All Gateway





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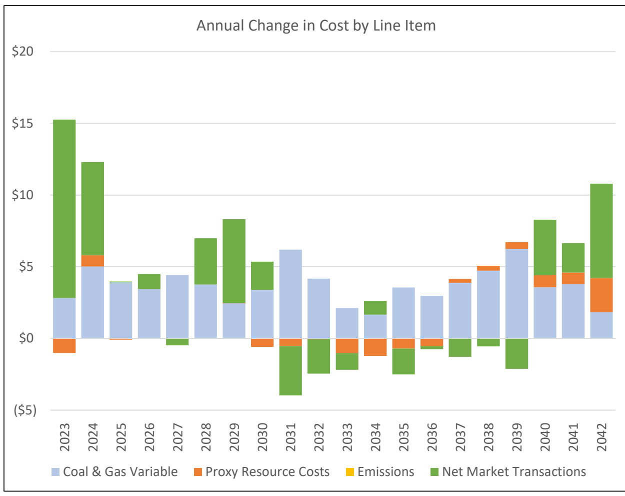

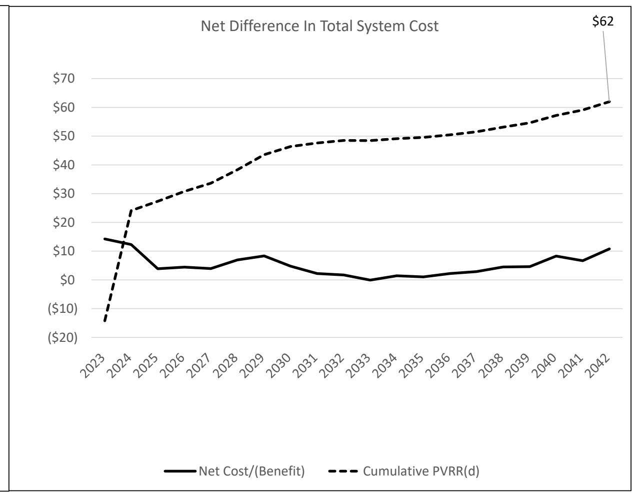

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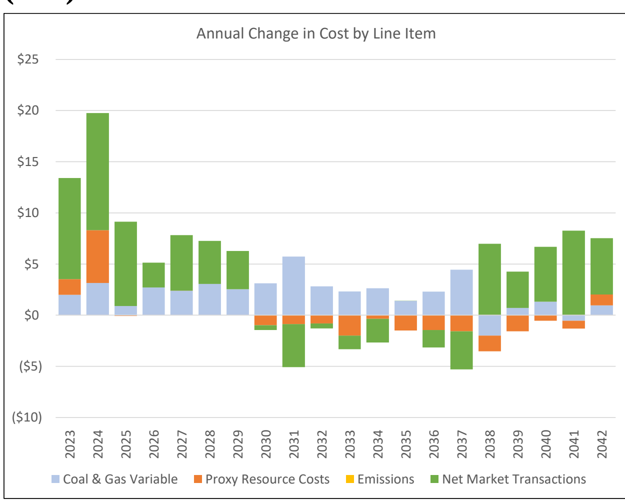
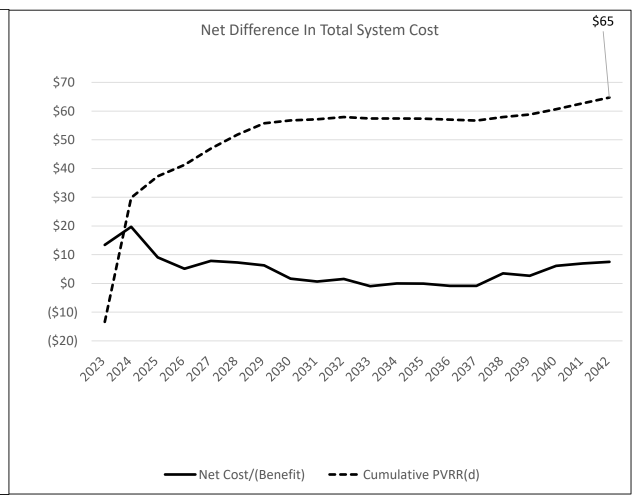
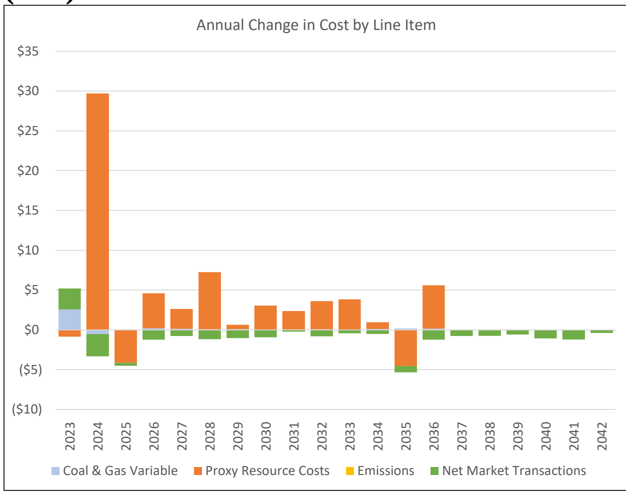
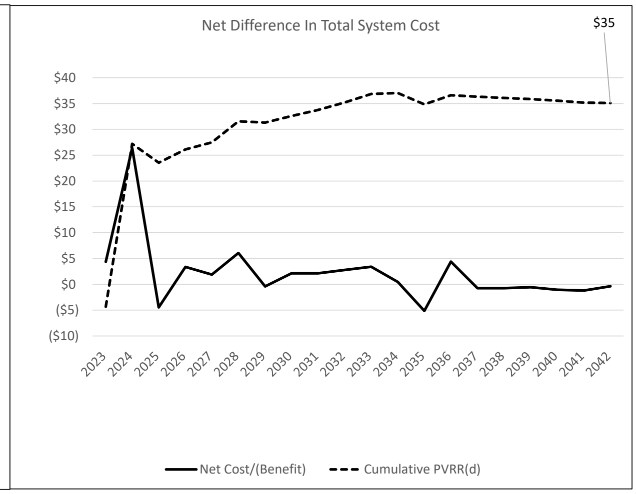


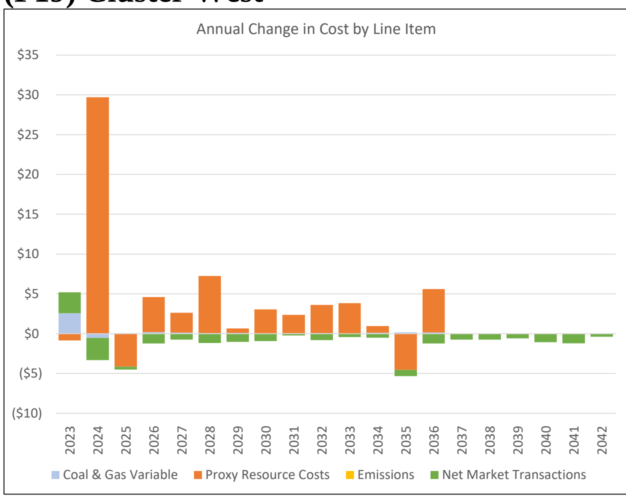


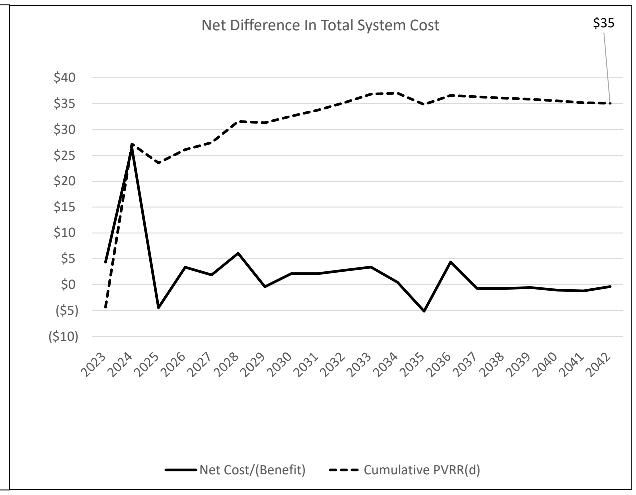
(P18) Cluster East





(P19) Cluster West





APPENDIX K – CAPACITY CONTRIBUTION

Introduction

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

In the 2019 IRP, PacifiCorp developed initial capacity contribution estimates for wind and solar capacity that accounted for expected declining contributions as the level of penetration increased. A key assumption in this analysis was that only a single variable was modified, for example, when evaluating solar penetration level, the capacity from wind and energy storage resources in the portfolio were held constant. As the preparation of the 2019 IRP continued, PacifiCorp identified that these initial estimates did not adequately account for the interactions between solar, wind, and energy storage and thus did not ensure that each portfolio was adequately reliable. Therefore, as part of the 2019 IRP PacifiCorp assessed each portfolio to verify that it would support reliable operation in each hour of the year. PacifiCorp has continued to perform this portfolio-wide reliability assessment as part of the 2021 and 2023 IRPs.

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

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

Method calculates the marginal capacity contribution of a one megawatt resource addition. Changes to the locations and quantities of wind, solar, and energy storage are key drivers of the marginal capacity contribution results.

CF Methodology

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

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

The weighting factors based on LOLP are defined as:

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

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

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

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

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

1. A multi-iteration hourly Monte Carlo simulation of PacifiCorp's system was produced using the Plexos Short-Term (ST) model. The key stochastic variables assessed as part of this analysis are loads, thermal outages, and hydro conditions. The LOLP for each hour in the year is calculated by counting the number of iterations in which system load and/or reserve obligations could not be met with available resources and dividing by the total

number of iterations.[2] For example, if in hour 19 on December 22nd there are three iterations with shortfalls out of a total of 50 iterations, then the LOLP for that hour would be 6 percent.[3]

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

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

For resources which are energy limited, such as energy storage or demand response programs, the LOLP values in each iteration must be examined independently, to ensure that the available storage or control hours are sufficient. Continuing the example of December 22nd described above, consider if hour 18 and hour 19 both have three hours with energy or reserve shortfalls out of 500 iterations. If all six shortfall hours are in different iterations, a 1-hour energy storage resource could cover all six hours. However, if the six shortfall hours are in the same three iterations in hour 18 and hour 19 (i.e. 2-hour duration events), then a 1-hour storage resource could only cover three of the six shortfall hours.

Additional considerations are also necessary for hybrid resources which share an interconnection and cannot generate their maximum potential output simultaneously.
The details of the wind and solar resource modeling in the study period are an important aspect of the results. The study includes specific wind and solar volumes by resource for each hour in the period and includes the effects of calm and cloudy days on resource output. Where data was available, the modeled generation profiles for proxy resources are derived from calendar year 2018 hourly generation profiles of existing resources, adjusted to align with the expected annual output of each proxy resource.

The use of correlated hourly shapes produces variability across each month and a reasonable correlation between resources of the same type that are located in close proximity. It also results

[2] While PacifiCorp participates in the Northwest Power Pool (NWPP) reserve sharing agreement, this only provides energy from other participants within the first hour of a contingency event, e.g. a forced outage of a generator or transmission line. Shortfalls in the 2023 IRP are much more likely to result from changes in load, renewable resource output, or energy storage limitations, which do not qualify as contingency events. In light of this, PacifiCorp's analysis includes the first hour of every shortfall event.
[3] 0.6 percent = 3 / 500.
[4] For each hour, the hourly LOLP is calculated as the number of iterations with ENS divided by the total of 500 iterations. There are 288 winter ENS iteration-hours out of total of 5,832 winter hours. As a result, the sum of LOLP for the winter is 288 / 500 = 58 percent. There are 579 summer ENS iteration-hours out of total of 2,928 summer hours. As a result, the sum of LOLP for the summer is 579 / 500 = 116 percent.
[5] 1.0417 percent = 0.6 percent / 58 percent, or simply 1.0417 percent = 3 / 288.
[6] 0.4271 percent = 1.0417 percent x 41.0 percent.

in days with higher generation and days with lower generation in each month. As one would expect, days with lower renewable generation are more likely to result in shortfall events. As a result, basing CF Method capacity contribution calculations on an average or 12-month by 24-hour forecast of renewable generation will tend to overstate capacity contribution, particularly if there is a significant quantity of similarly located resources of the same type already in the portfolio, or if an appreciable quantity of resource additions is being contemplated. Even if an hourly renewable generation forecast is used, capacity contributions can be overstated if the weather underlying the forecast is not consistent with that used for similarly located resources used to develop the CF Method results. Because similarly located resources of the same type would experience similar weather in actual operations, a mismatch in the underlying weather conditions used in renewable generation forecasting will create diversity in the generation supply than would not occur in actual operations.

Because they are both influenced by weather, a relationship between renewable output and load is expected. To assess this relationship, PacifiCorp gathered information on daily wind and solar output from 2016-2019 and compared it to the load data from that period, the same load data that was used to determine stochastic parameters.

Each of the days in the historical period was assigned to a tier based on the rank of its daily average load within that month. This was done independently for the east and west sides of the system. The seven tiers were defined as follows:

Tier 1: The peak load day

Tier 2: 2nd – 5th highest load days

Tier 3: Days 6-10

Tier 4: Days 11-15

Tier 5: Days 16-20

Tier 6: Days 21-25

Tier 7: Days 26-31

The average wind and solar generation on the days in each tier was then compared to the average wind and solar generation for the entire month. The results indicated that west-side wind is often below average during the highest load days in a month, and above average during the lowest load days in a month. The results for other resource types were less pronounced, but do exhibit some patterns, as shown in Figure K.1 and Figure K.2.

Figure K.1 – Renewable Resources vs. High Load Conditions

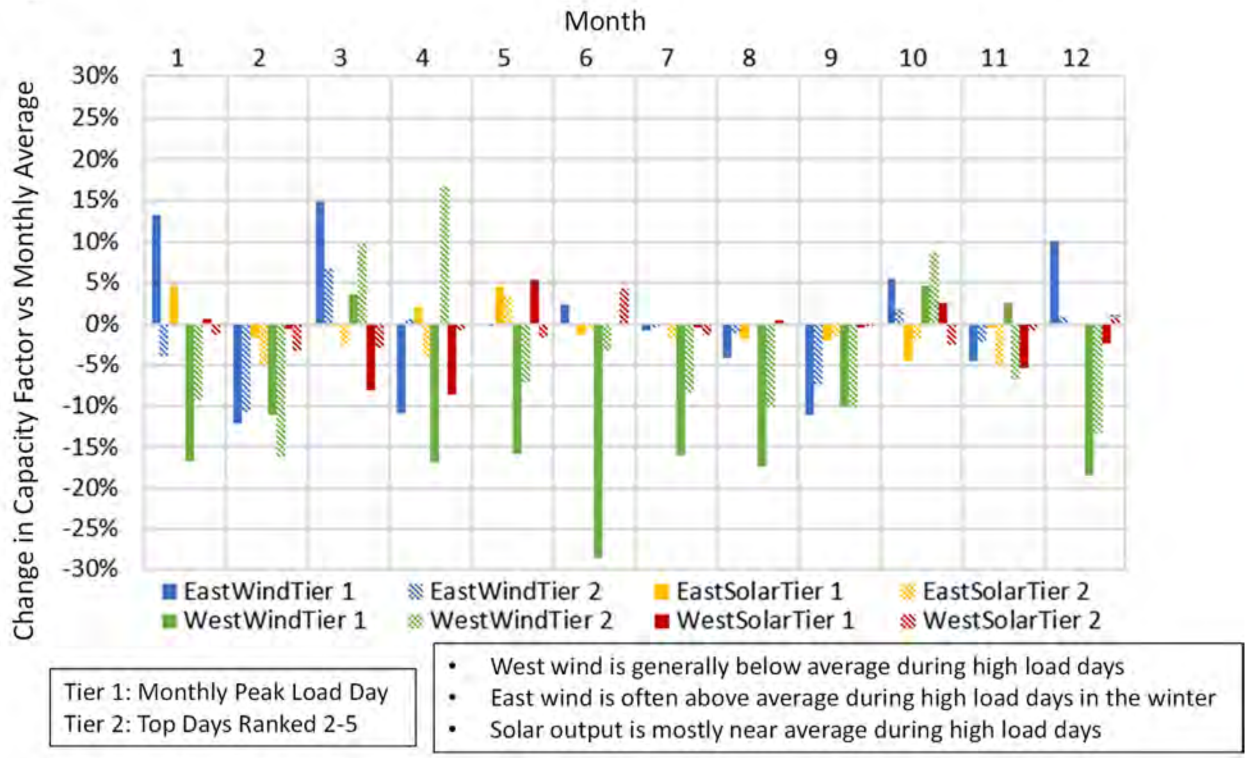
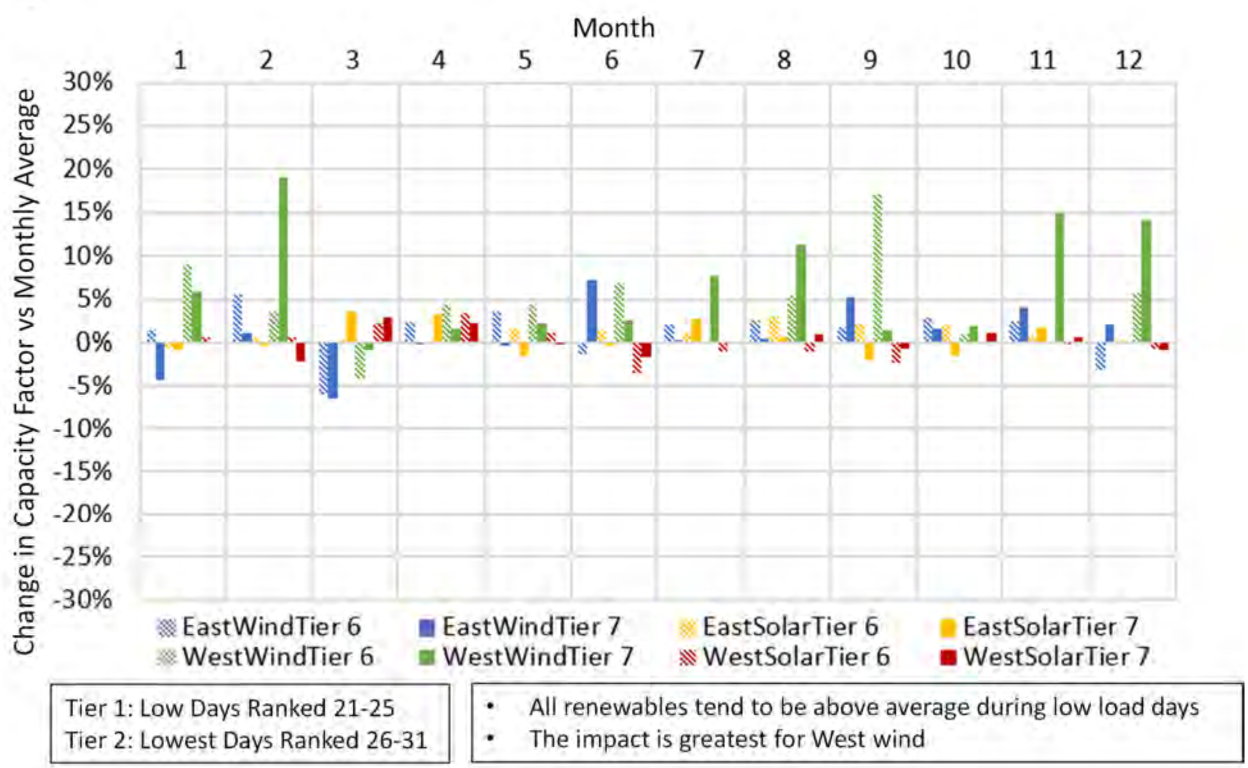


Figure K.2 – Renewable Resources vs. Low Load Conditions



Standard stochastic evaluation of prices, loads, etc. is based on standard deviations and mean reversion statistics. The results indicate that wind and solar output does exhibit relationships with load, but they are poorly represented by standard deviations – a different modeling technique is necessary.

Because of the complexity of the data, PacifiCorp did not attempt to develop wind and solar generation that varies by stochastic iteration for the 2023 IRP. Instead, PacifiCorp used a technique using the existing input framework: a single 8760 profile for each wind and solar resource that repeats every year. Because the load forecast rotates with the calendar, such that the peak load day moves to different calendar days, this creates differences in the alignment of load and renewable output across the IRP study horizon.

The order of the 2018 historical days was rearranged so that the forecasted intra-month variation in renewable output was reasonably aligned with the intra-month variation observed in the historical period for the days in the same load tier. Each day of renewable resource output derived from the 2018 history is mapped to a specific day for modeling purposes – only the order of the day's changes. To maintain correlations within wind and solar output, all wind and solar resources across the entire system are mapped using the same days.

While this technique builds on previous modeling and produces a reasonable forecast that captures some of the relationships between wind, solar, and load, additional work is needed in future IRPs to explore the variation and diversity of solar and wind output and further relationships with load.

APPENDIX L – PRIVATE GENERATION STUDY

Introduction

DNV prepared the Private Long-Term Resource Assessment for PacifiCorp. A key objective of this research is to assist PacifiCorp in developing private generation resource penetration forecasts to support its 2023 Integrated Resource Plan. The purpose of this study is to project the level of private generation resources PacifiCorp's customers might install over the next twenty years under low, base and high penetration scenarios.

PRIVATE GENERATION FORECAST

Behind-The-Meter Resource Assessment

PacifiCorp

Date: February 2, 2023

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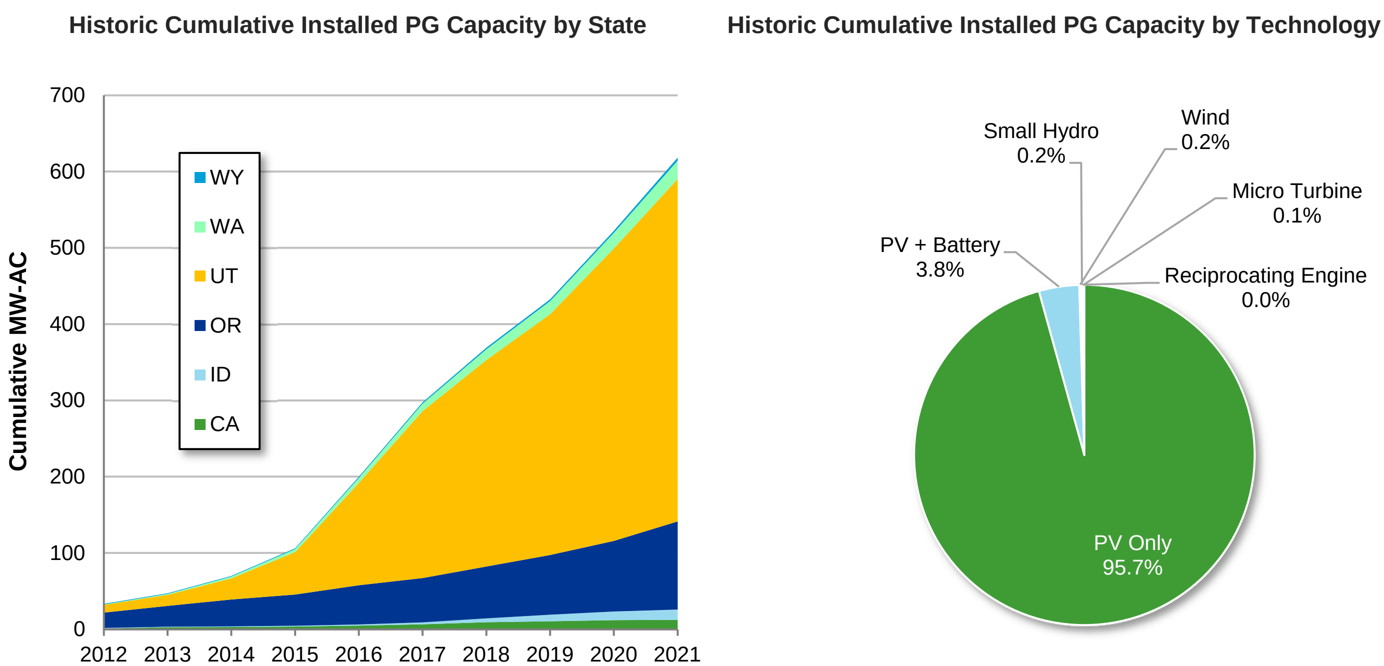
1 EXECUTIVE SUMMARY

DNV prepared the Long-Term Private Generation (PG) Resource Assessment for PacifiCorp (the Company) covering their service territories in Utah, Oregon, Idaho, Wyoming, California, and Washington to support PacifiCorp's 2023 Integrated Resource Plan (IRP). This study 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 (2023-2042) for all customer sectors (residential, commercial, industrial, and agricultural). The adoption model DNV developed for this study is calibrated to the current[1] installed and interconnected capacity of these technologies, shown in Figure 1-1.

Figure 1-1 Historic Cumulative Installed Private Generation Capacity, PacifiCorp, 2012-2021



To date, the majority of PG installed capacity and annual growth in capacity has been in Utah, which represents the largest portion go PacifiCorp's customer population—about 50% of all PacifiCorp customers are in the Company's Utah service territory. Roughly 99 percent of existing private 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 private generation market in the Company's service territory in the future years of this study.

For each technology and sector, DNV developed three adoption scenarios: 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.

[1] PacifiCorp private generation interconnection data as of February 2022.

All scenarios use technology cost and performance assumptions specific to each state in PacifiCorp's service territory in the base year (2022) of the study. The base case uses the 2022 federal income tax credit schedules[2] and state incentives, retail electricity rate escalation from the AEO[3] reference case, and a blended version of the NREL Annual Technology Baseline[4] 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. For the low case, retail electricity rates increase at a slower rate than the base case and technology costs decrease at a slower rate.

1.1 Study Methodologies and Approaches

The forecasting methodologies and techniques applied by DNV in this analysis are commonly used in small-scale, behind-the-meter 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 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 study 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.

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 that are prone to outages and severe weather events.

DNV combined technical feasibility characteristics of the identified PG 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 PG adoption based on technical and

[2] H.R.5376 - Inflation Reduction Act of 2022 (https://www.congress.gov/bill/117th-congress/house-bill/5376/text). Since the passing of the Inflation Recovery Act of 2022, the federal Investment Tax Credit (ITC) has been extended past its original expiration date for ten years. For facilities beginning construction before January 1, 2025, the bill will extend the ITC for up to 30 percent of the cost of installed equipment for ten years and will then step down to 26 percent in 2033 and 22 percent in 2034.

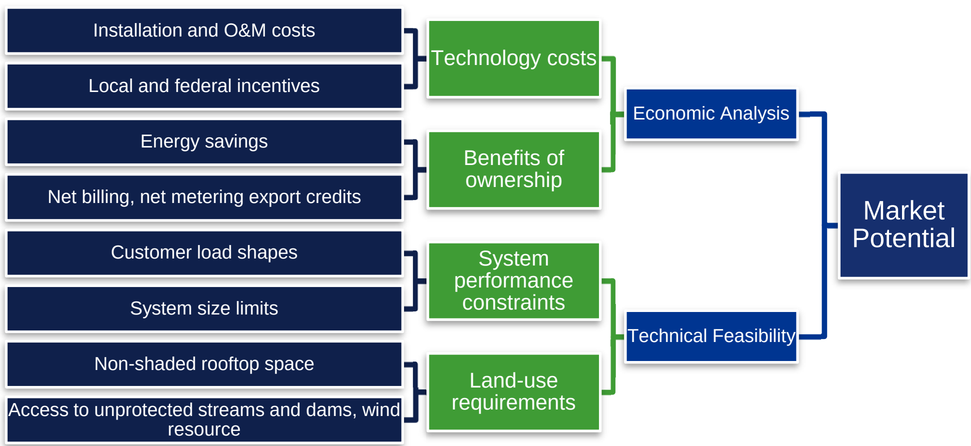
[3] U.S. Energy Information Administration, Annual Energy Outlook 2022 (AEO2022), (Washington, DC, March 2022).

[4] NREL (National Renewable Energy Laboratory). 2021. 2021 Annual Technology Baseline. Golden, CO: National Renewable Energy Laboratory.

economic feasibility and incorporated existing adoption of each PG technology by state and customer segment as an 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 PG technology, or the maximum, feasible, adoption for each technology by sector. These factors included overall PG 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 future penetration of all PG technologies. The methodology and major inputs to the analysis are shown in Figure 1-2. Changes to technology costs and retail electricity rates used in the high and low cases impact the economic portion of the analysis.

Figure 1-2 Methodology to Determine Market Potential of Private Generation Adoption



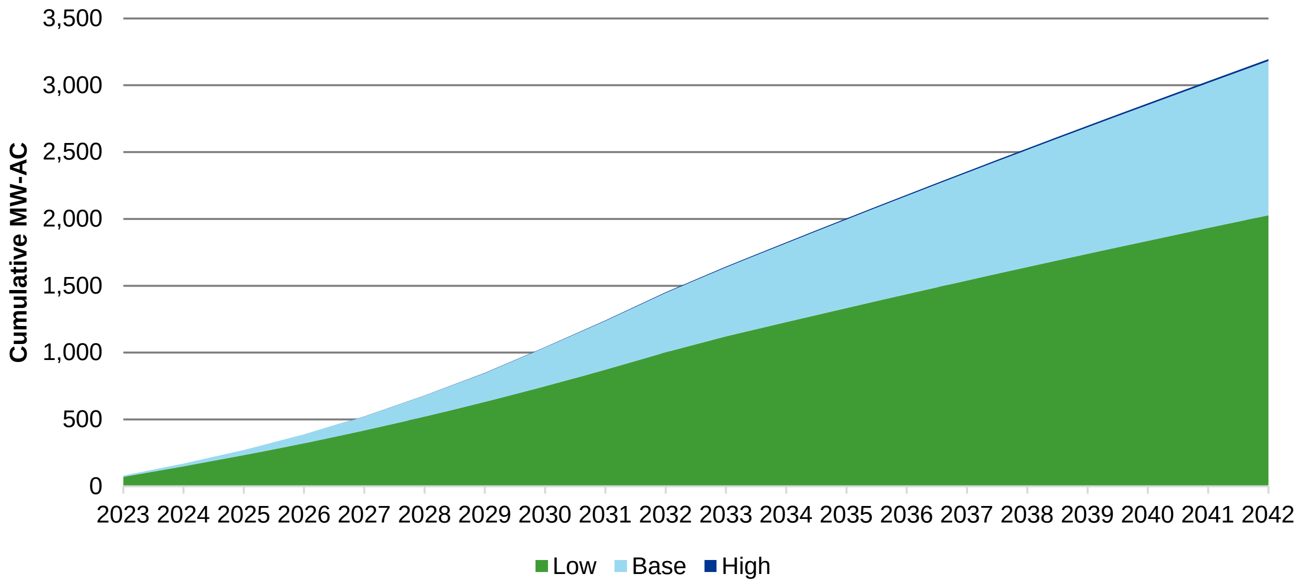
DNV developed Bass diffusion curves customized for each technology, state, and sector that also accounted for variation in willingness-to-adopt as cost effectiveness changes over time. The Bass diffusion curves were used to model annual and cumulative market adoption. Bass diffusion curves are widely 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 the maximum level of market 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 vary 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 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. The calibrated curves show some segments still in the very early phases of adoption, while other markets are more mature.

1.2 Private Generation Forecast

In the base case scenario, DNV estimates 3,181 MW of new private generation capacity will be installed in PacifiCorp's service territory over the next twenty years (2023-2042). Figure 1-3 shows the base, low and high case scenarios. The low case scenario estimates 2,028 MW of new capacity over the 20-year forecast while the high case estimates 3,196 MW of new private generation capacity installed by 2042.

Figure 1-3 Cumulative New Capacity Installed by Scenario (MW-AC), 2023-2042



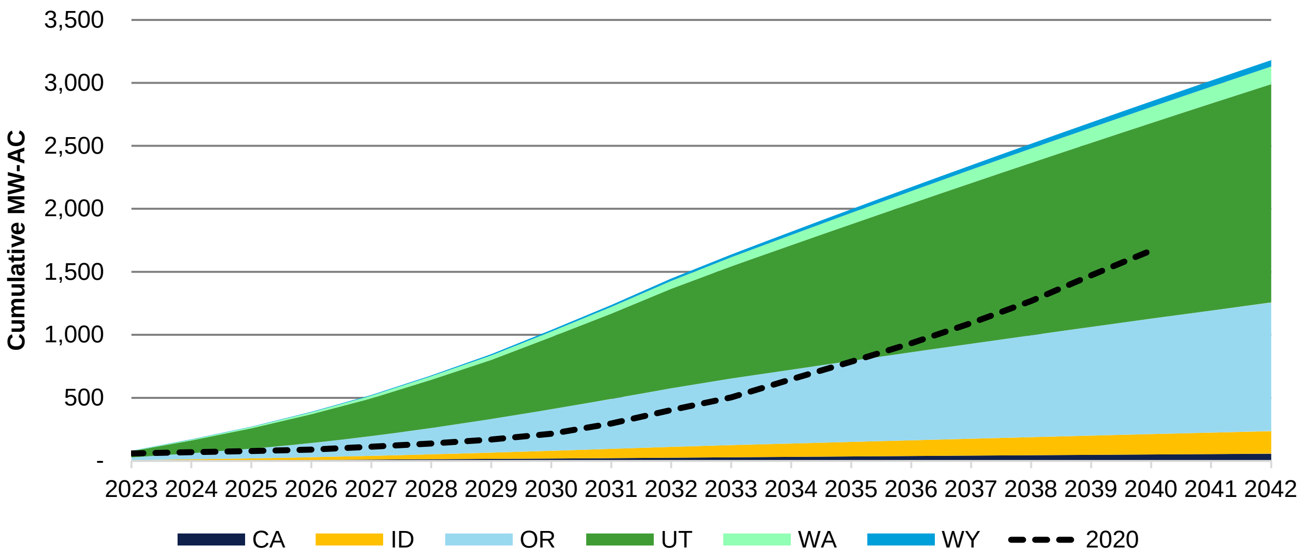
The sensitivity analysis showed a much greater margin of uncertainty on the low side than the high side. The Inflation Reduction Act of 2022 (IRA) extends tax credits for private generation that create very favorable economics for adoption, and those are embedded in the base case. We therefore limited 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 increases to customer payback period were enough to tamp down adoption by a wider margin. The low case assumed higher technology costs and lower retail electricity rates than the other cases, reducing the economic appeal of private generation despite incentives being unchanged. The low case forecast is 36% less than the base case, while the high case cumulative installed capacity forecasted over the 20-year period is just 0.5% greater than the base case.

Figure 1-4 shows the base case forecast by state, compared to the previous (2020) study's total base case forecast.[5] 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. The base scenario estimates approximately 1,447 MW of new capacity will be installed over the next 10 years in PacifiCorp's territory—55% of which is in Utah, 32% in Oregon, and 6% in Idaho. Since the 2020 study, the federal Investment Tax Credit (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

[5] Cumulative capacity is adjusted to account for the difference in the forecast starting years (2021 in the previous study, versus 2023 in this study). Source: Navigant. 2020. "Private Generation Long-Term Resource Assessment (2021-2040)"

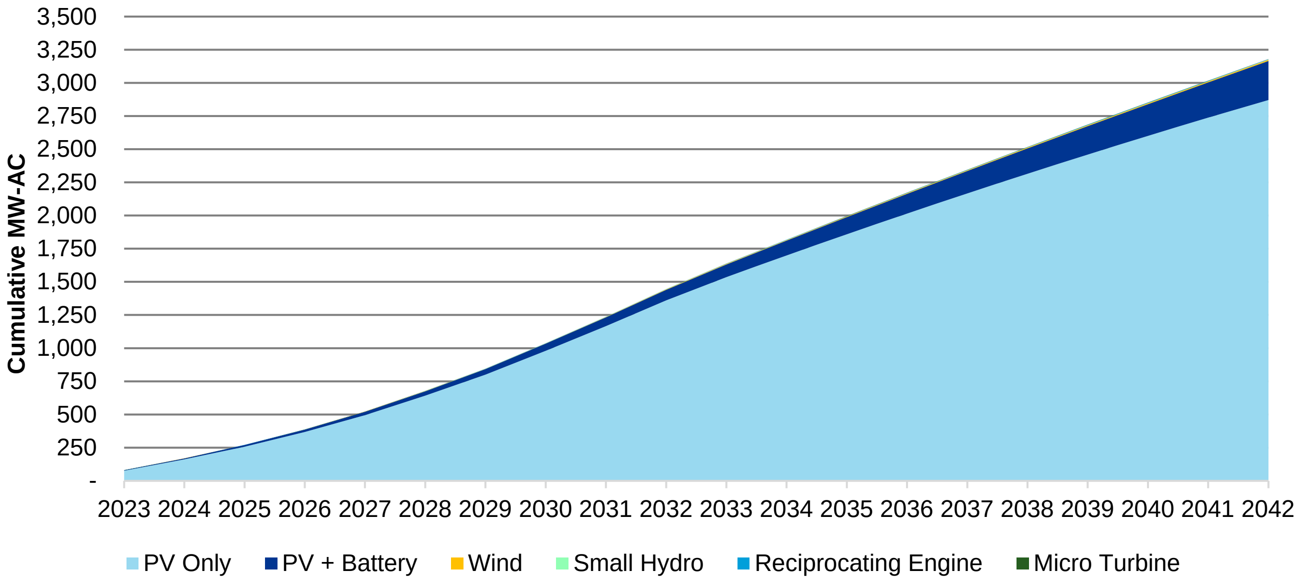
similar to the previous study's high case. In addition to the change in customer economics, projected PV capacity is expected to grow at a faster rate in the early years and at a slower rate towards the end of the forecast period. The key drivers of these differences include larger average PV system sizes, 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), 2023-2042, 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 76 MW and PV + Battery by 3 MW. These two technologies make up 99% of new installed private generation capacity forecasted. The results section of the report contains results by technology for the high, base, and low sectors. Additionally, total PV capacity forecasted is presented by sector in that section as well.

Figure 1-5 Cumulative New Capacity Installed by Technology (MW-AC), 2023-2042, Base Case



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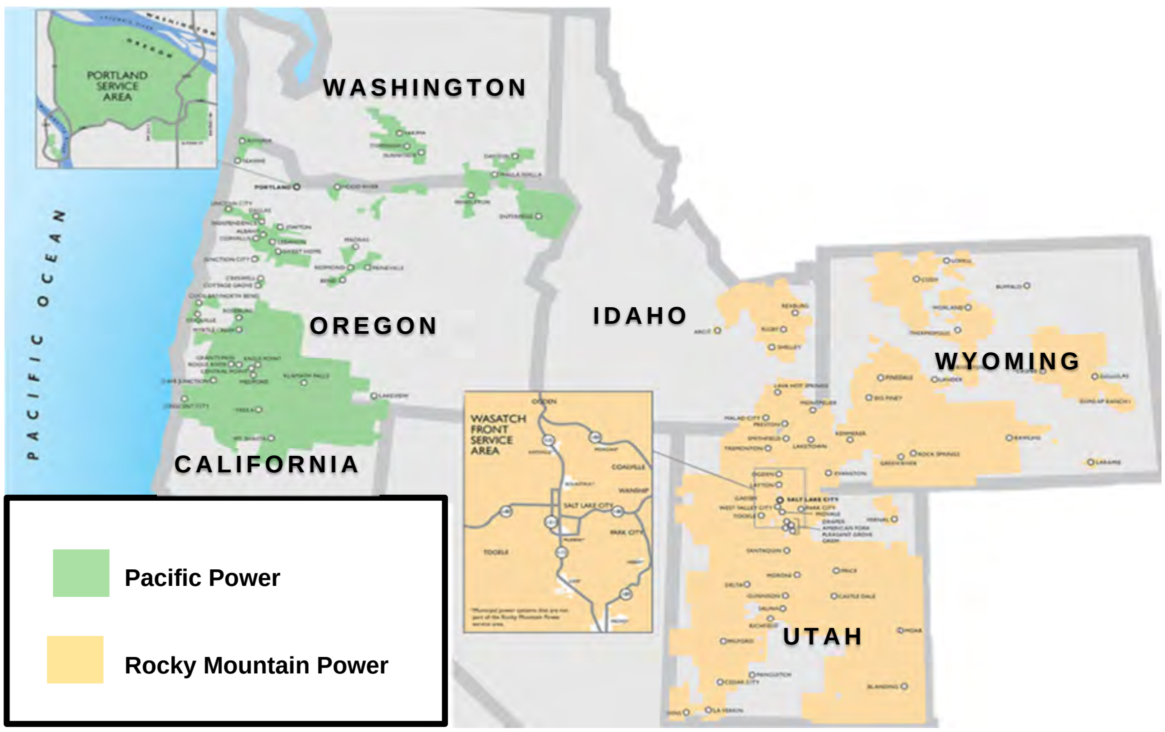
2 STUDY BACKGROUND

DNV prepared this Private Generation Long-term Resource Assessment on behalf of PacifiCorp and representing their service territory in six states—shown in Figure 2-1—California, Idaho, Oregon, Utah, Washington, and Wyoming. In this study, private generation technologies provide behind-the-meter energy generation at the customer site and are designed for the purpose of offsetting customer load and/or peak demand. The purpose of this study is to support PacifiCorp's 2023 Integrated Resource Plan by projecting the level of private generation resources PacifiCorp's customers may install over the next two decades under base, low, and high adoption scenarios. In addition to private 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



Although there have been six previous studies involving private generation, DNV developed its assumptions, inputs, methodologies, and forecasts independently from these prior assessments that had been performed for PacifiCorp. The forecasting methodologies and techniques applied by DNV in this analysis are commonly used in small-scale, behind-the-meter energy resource and energy efficiency forecasting. This study evaluated the expected adoption of behind-the-meter 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. Private generation adoption for each technology was estimated by sector in each state in PacifiCorp's service territory.

3 STUDY APPROACH AND METHODS

DNV used applicability/ technical feasibility, customer perspectives towards PGs, and project economics as the basis for forecasting expected market adoption of each private 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 thepayback and adoption analyses. A full list of detailed technology attributes and assumptions by state and sector is provided in Appendix A. The following information provides a high-level summary of the key elements of the technologies assessed in this analysis.

3.1.1 Solar PV

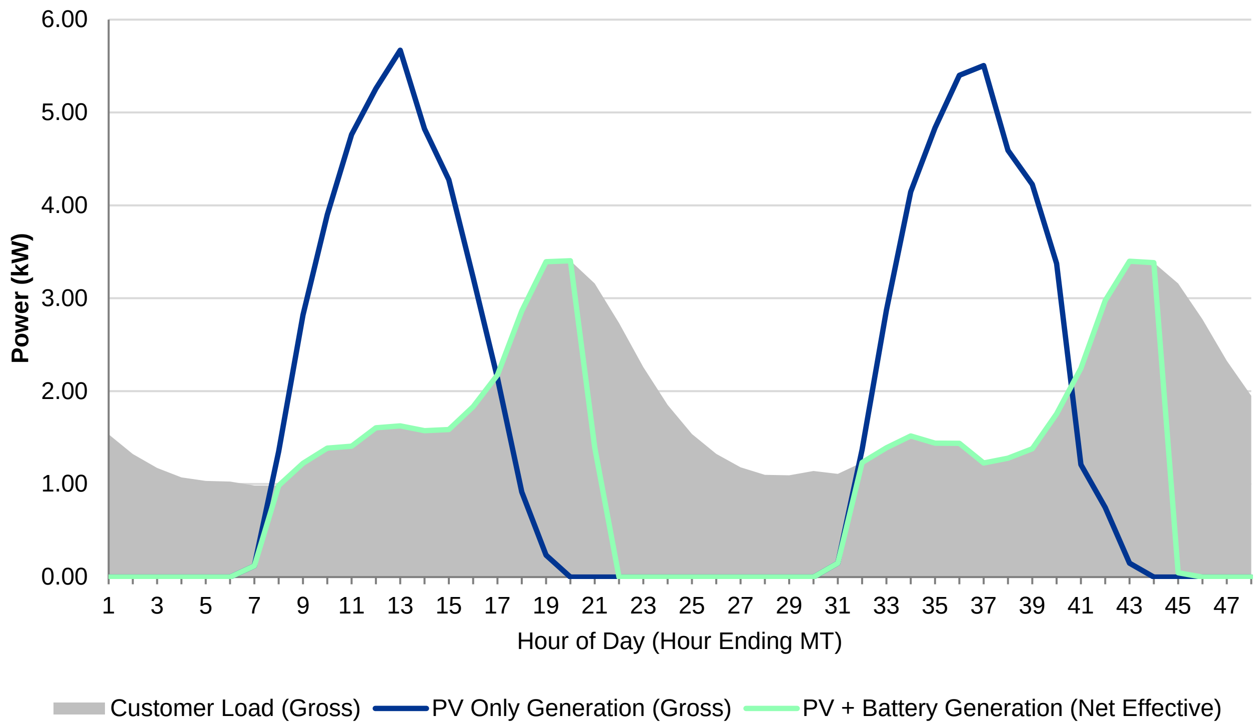
Solar photovoltaic (PV) systems convert sunlight into electrical energy. DNV modeled representative PV system energy output for residential and non-residential systems in each state to estimate first-year production. To model hourly production, DNV leveraged its SolarFarmer and Solar Resource Compass 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 both dust soiling and snow soiling, as well as a monthly albedo profile. By incorporating industry standard models and DNV analytics, precipitation and snowfall data is 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 were modeled using the same specifications as the PV Only technology, with the exception of 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 by 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 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 in this analysis.

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	6.0	6.8	5.5	10.0	5.5
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 is dependent 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	30-150	37-100	30-115	60-750	20-100	18-25
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 Appendix A. 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 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 sector are listed in Appendix A.

Table 3-3 Residential PV + Battery Representative System Assumptions

Technology	System Performance	Units	CA	ID	OR	UT	WA	WY
PV	Nameplate Capacity	kW-DC	9.5	8.8	10.6	8.1	13.6	8.6
BESS	Total Usable Energy Capacity	kWh	12.5	12.5	14.0	12.5	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%					
	Battery Pack Chemistry	n/a	Lithium-ion NMC (Nickel, Manganese, Cobalt)					

Residential and non-residential BESS can be installed as a standalone system, added to an existing PV system, 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 systems are ineligible for the federal ITC—explained further in section 3.2.5.

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 the purpose of forecasting private generation capacity, the Battery Retrofit forecast is presented in the results section as a part of the PV + Battery capacity forecast. In the behind-the-meter battery storage capacity forecast, presented in Appendix E, 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 models several current-generation, commercially available Nickel Manganese Cobalt (NMC) cells were used to predict expected degradation performance of "generic" cells. These cells were tested in the lab over periods of 6 – 12 months at multiple temperatures, C-rates, SOC ranges, and cycling/resting conditions. Predictions are generally constrained to 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 of 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 majority of the time with proper thermal management (ventilation, HVAC). DNV notes that temperature plays a key role in battery degradation. Continuous operation under extreme low or high temperatures will accelerate degradation in battery 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, inclusive of hardware, labor, permitting and interconnection fees, as well as provisions for sales and marketing, overhead, and profit. For labor costs, we used state level data from the US Bureau of Labor Statistics (BLS) for electricians, laborers (construction), and electrical engineers.

Total installed costs (or capital expenditures) are based on cost assumptions that were 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 is indicative of a cash sale, not a lease or PPA, and it does not account for 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.

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

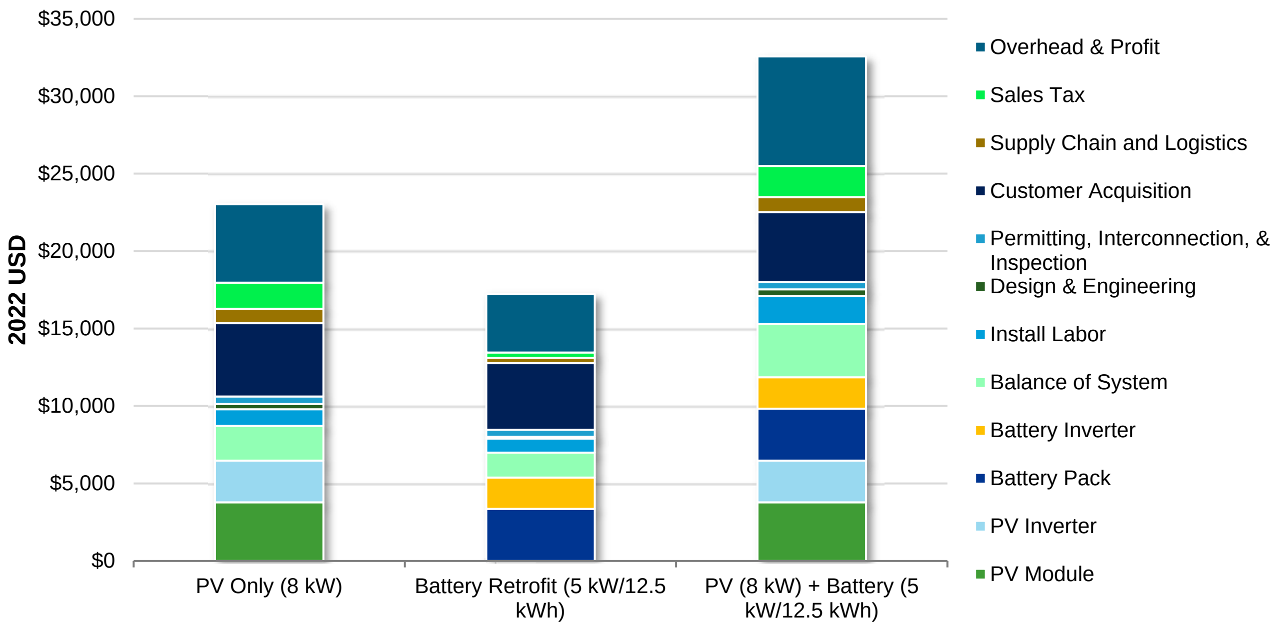
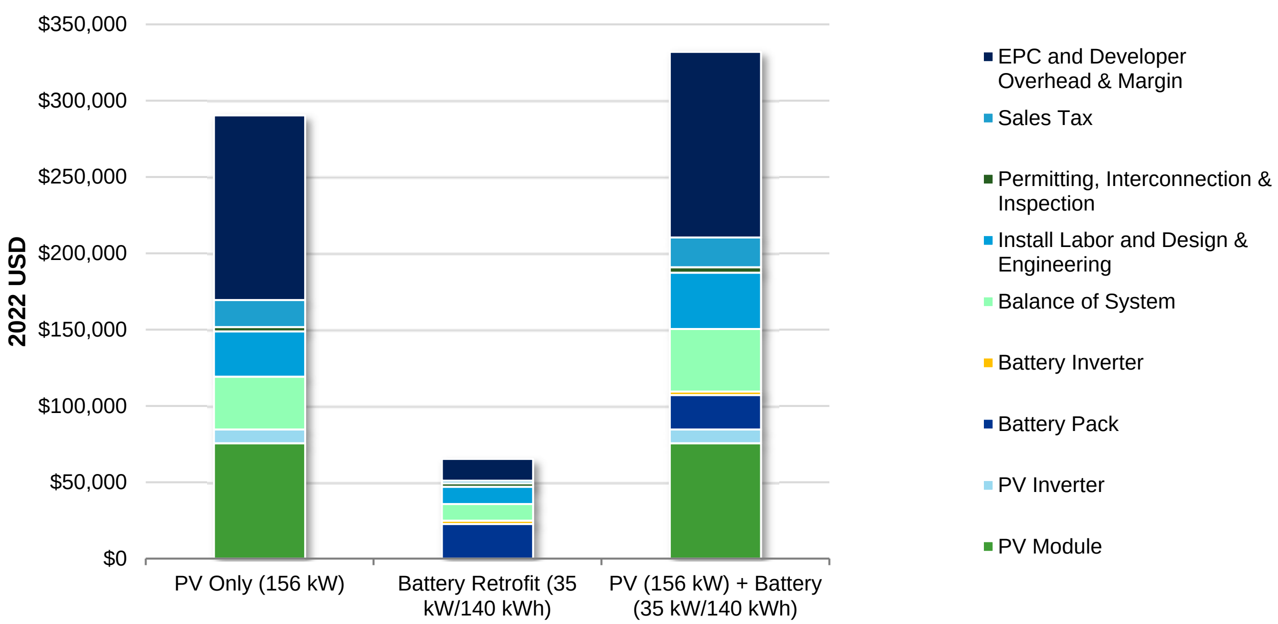


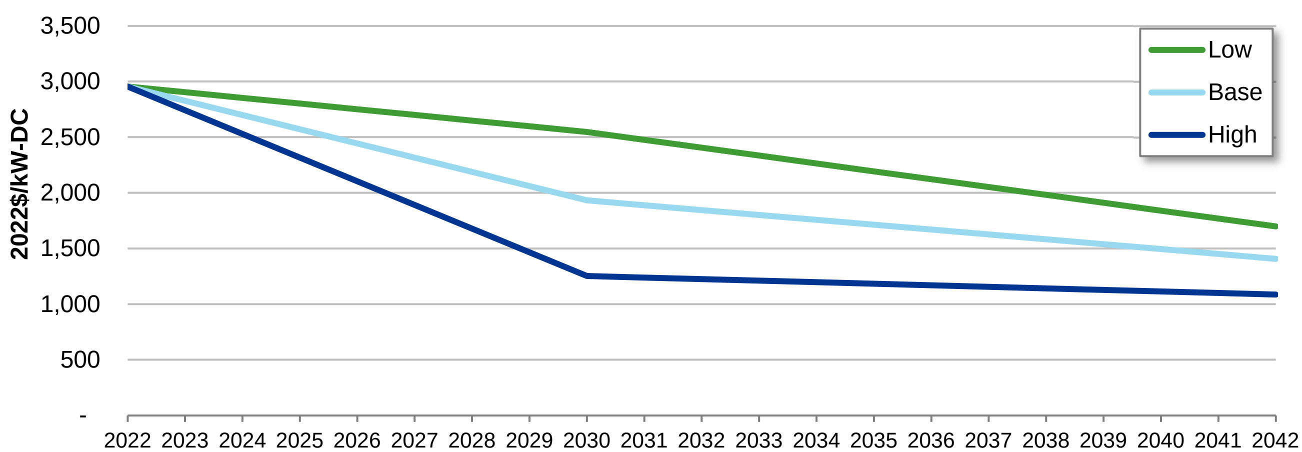
Figure 3-3 Cost of Commercial PV Standalone, Battery Storage Retrofit to Existing PV, and PV + Battery Systems from DNV Bottom-up Cap-Ex Model, Utah



DNV has estimated all CapEx categories for the projects based on Wood Mackenzie's US 2022 H1 cost model, which has been found to be reasonable relative to actual CapEx that DNV has observed on projects it's reviewed in the past. 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 and logistics, and overhead and profit costs.

DNV used a blended version of the NREL Annual Technology Baseline[6] moderate and conservative solar PV and battery energy storage system technology cost forecasts in the base case of this private 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. 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.

Figure 3-4   Average Residential Solar PV System Costs, 2023-2042



6NREL (National Renewable Energy Laboratory). 2021. 2021 Annual Technology Baseline. Golden, CO: National Renewable Energy Laboratory.

Figure 3-5   Average Non-Residential Solar PV System Costs, 2023-2042

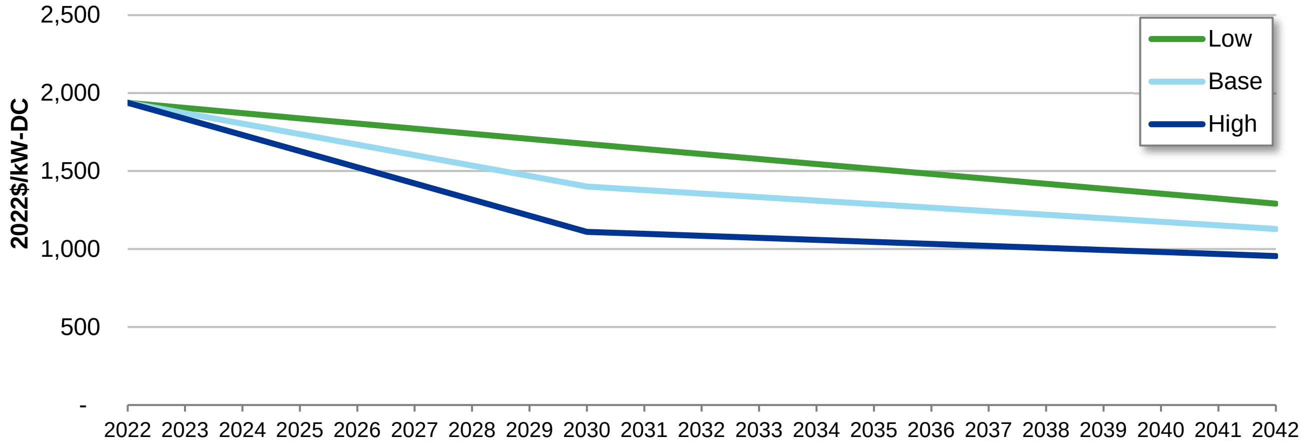


Figure 3-6   Average Residential Battery Energy Storage System (AC-Coupled) Costs, 2023-2042

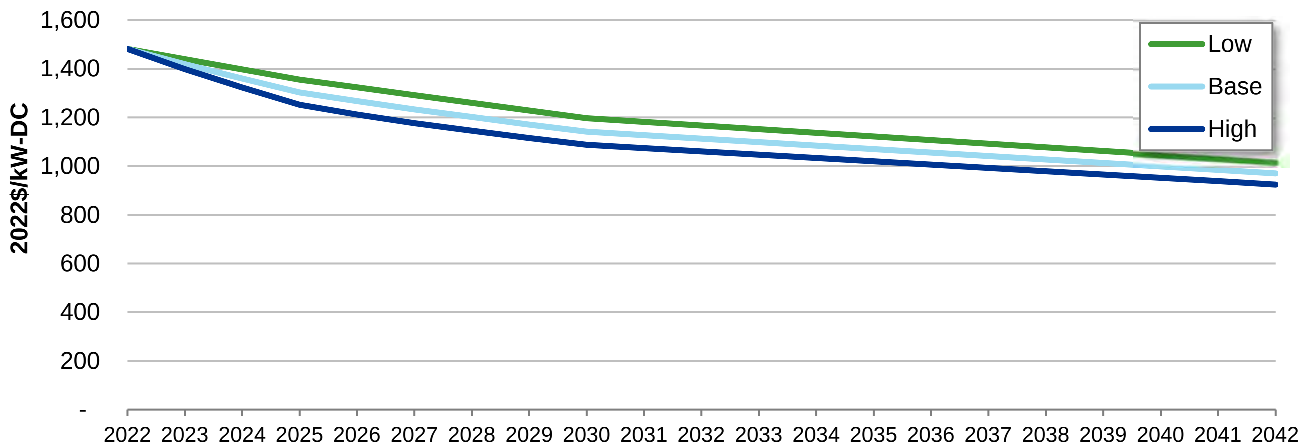
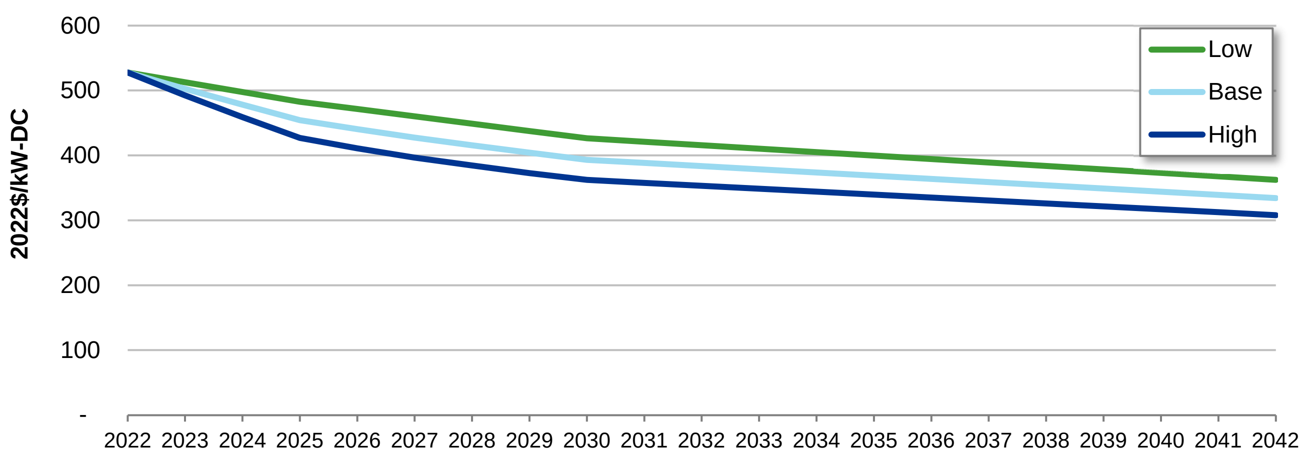


Figure 3-7   Average Non-Residential Battery Energy Storage System (AC-Coupled) Costs, 2023-2042



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 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. 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	2022$/kW	$6,185	$4,686	$3,015	NREL, 2022. Distributed Wind Energy Futures Study. https://www.nrel.gov/docs/fy22osti/82519.pdf
Annual Installed Cost Change	%, 2022-2042	-1.9%			NREL. 2021. "2021 Annual Technology Baseline." Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/
Fixed O&M	2022$/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	%, 2022-2042	-3.5%	-1.9%	-1.9%	NREL. 2021. "2021 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 2021.12.2. 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 therefore are still quite costly compared to other private 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. 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	2022$/kW	$5,190	$3,892	International Renewable Energy Agency (IRENA). 2012. "Renewable Energy Cost Analysis: Hydropower"

Annual Installed Cost Change	%, 2022-2042	-0.2%		NREL. 2021. "2021 Annual Technology Baseline." Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/
Fixed O&M	2022$/kW-yr	$208	$156	International Renewable Energy Agency (IRENA). 2012. "Renewable Energy Cost Analysis: Hydropower"
Annual Fixed O&M Cost Change	%, 2022-2042	-1.9%		NREL. 2021. "2021 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 private 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 perform 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 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 or low-pressure steam, or chilled water with the additional 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.[7]

Assumptions on system capacity sizes in each state and sector are detailed in Appendix A. Two representative reciprocating engine sizes were used in this analysis based on the ability to meet average customer 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	2022$/kW	$4,189	$3,183	"A Comprehensive Assessment of Small Combined Heat and Power Technical and Market Potential in California." 2019. California Energy Commission.
Annual Installed Cost Change	%, 2022-2042	-0.5%		NREL. 2021. "2021 Annual Technology Baseline." Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/

[7] U.S. Department of Energy Combined Heat and Power and Microgrid Installation Databases (2022). Available at: https://doe.icfwebservices.com/chp

Variable O&M	2022$/MWh	$28	$25	"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	%, 2022-2042	-1.9%		NREL. 2021. "2021 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.

3.1.5 Microturbines

Microturbines are another CHP application that are commonly used in smaller commercial and inustrial 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 will 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 additional 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 Northwestinclude small universities, commercial buildings, small manufacturing operations, hotels, and wastewater treatment facilities.[7]

Assumptions on system capacity sizes in each state and sector are detailed in Appendix A. Two representative microturbine sizes were used in this analysis based on the ability to meet average customer minimum electric load, ranging from less than 100 kW to 1 MW. Table 3-7 provides the cost and performance assumptions used in the reciprocating engine 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	2022$/kW	$3,742	$3,686	"A Comprehensive Assessment of Small Combined Heat and Power Technical and Market Potential in California." 2019. California Energy Commission.
Annual Installed Cost Change	%, 2022-2042	-0.6%		NREL. 2021. "2021 Annual Technology Baseline." Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/
Variable O&M	2022$/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	%, 2022-2042	-1.9%		NREL. 2021. "2021 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.

3.2 Customer Perspectives

Customers' attitudes towards, and general understanding of, private generation technologies, projects, and initiatives currently being promoted in the market today will vary based on a variety of factors covered in this section. DNV has combined internal expertise with an aggregation of customer-focused research from reputable sources to understand overall trends in customer sentiment and insights specifically related to private generation for residential or nonresidential buildings.. Some of the key motivators and barriers to private generation technology adoption are presented in Table 3-8.

Table 3-8 Motivators and Barriers for Private Generation Technology Adoption

TECHNOLOGY	MOTIVATORS	BARRIERS
ALL	• Cost savings • Reducing carbon footprint	• Educational awareness • Proactive involvement from customer • Minimal understanding of technology applications
SOLAR PV	• Cost savings • Reducing carbon footprint • Attractive financing options	• Initial investment • Infrastructure requirements i.e., physical space and roof quality • Perception as a technology for the affluent
BATTERY STORAGE	• Cost savings • Resilience/backup power • likelihood to experience to severe weather • Reduce peak consumption	• Low levels of awareness and understanding • Short duration capability for backup • Limited monetization opportunities • Physical space and roof quality • Initial investment • Limited use cases for storage-only
SOLAR + BATTERY	• Resilience/backup power • ITC applicability window • Maximize solar generation • Cost savings • Reducing carbon footprint	• Initial investment • Infrastructure requirements of solar

Customer adoption of solar, storage, and other PG-related solutions is primarily influenced by financial viability of the overall project and the associated return on investment or payback period. However, while the financial parameters and payment options for a project are certainly an important feature, customers will also face different barriers or motivators that will either encourage or discourage them from adoption despite the financial benefits.

For these reasons, research organizations have typically viewed adoption of new and innovative technologies by customer segments ranging from early adopters and enthusiasts to the majority and the laggards. Some customers may even be considered opposed to the innovation and will never adopt the technology. On the other hand, there also exists a consumer group that will move forward with adoption of DER offerings even when the financial numbers don't show the most desirable ROI or payback. This consumer group is more easilyinfluenced by sales and marketing strategies even when the numbers don't "add up" to a clear economic play. The following sections will provide further insights on how customer awareness, knowledge of energy costs and systems, and incentives can impact customer adoption of PG technologies.

3.2.1 Customer Awareness

While DERs, the term most commonly used to describe PG technologies is a common term within the energy industry, it is not commonly understood by the average consumer. Less than 10% of residential customers are clear on exactly what the term means and how it applies to them. Consumers are lacking a sound understanding of how DERs work, the tangible benefits they provide, and how they would operate within a home or business.

Customer education to build awareness is likely to lead to more growth of PG. Educational outreach and marketing should focus on accessible, feasible use-cases for technology applications in "real-world" settings that customers can relate to and see themselves using. Customers have a desire to improve their understanding of PG opportunities by obtaining quality information – most prefer their electricity provider as the source – about the savings potential of these technologies and details on how they work. [8]

3.2.2 Motivating Factors for Adoption

The primary motivators that prompt customers to consider implementing PG technologies are how much savings they can realize through a project and the level of incentives being awarded. Second to these financial motivators, customers are interested in PG opportunities as a method of reducing their environmental impact. Customers who are aware of PG opportunities often have a curiosity and desire to increase their understanding of the opportunities available to them as committing to a PG system or product requires the customer to have a greater level of involvement in their electricity generation, consumption, and management. While understanding and awareness of PG is a clear barrier to adoption, customers have the desire to obtain information to help them better understand these technologies. Energy providers can prioritize informative, engaging communication to increase the customers' understanding of DER opportunities, thus increasing their likelihood of adoption and participation.[7]

3.2.3 Barriers to Adoption

Trust and finances are common barriers to PG adoption– customers are often skeptical that these projects will perform as advertised and save the amount of money that is claimed. Customers need quality information to help them validate the investment in certain new technologies or programs that they do not have experience with. If the customer's goal for a PG system is to save money and they express the need to understand how much money the projects will save, accurate information needs to be available to prove those cases to the customer. Successful implementation of PG technologies and solutions will require changing the behavior and perception of a large portion of the customers.[7]

3.2.4 Other Considerations

Customers who participate in demand response programs are more likely to own a hybrid or electric vehicle, energy management system (EMS), or solar + storage system than customers who do not participate in demand response programs. A foundational piece for growing participation in DER initiatives can be first focusing on demand response programs as a way for customers to get started on their clean energy journeys. This concept of "DER stacking" enables a utility to prioritize targeting customers who are already participating in some form of demand response or PG-related program, thus giving the customer a more holistic solution for their energy management and consumption.[7]

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[8] SECC (Smart Energy Consumer Collaborative). 2019. Distributed Energy Resources: MEETING CONSUMER NEEDS. Pages 7 – 13.

3.2.5 Incentives Overview

Since the passing of the Inflation Recovery Act of 2022, the federal Investment Tax Credit (ITC) has been extended past its original expiration date for ten years. For facilities beginning construction before January 1, 2025, the bill will extend the ITC for up to 30 percent of the cost of installed equipment for ten years and will then step down to 26 percent in 2033 and 22 percent in 2034. For projects beginning construction after 2019 that are placed in service before January 1, 2022, the ITC would be set at 26 percent. In addition to the new federal ITC schedule for generating facilities, the updated ITC includes credits for standalone energy storage with a capacity of at least 3 kWh for residential customers and 5 kWh for non-residential customers. The bill also includes a 5-year MACRS depreciation schedule for non-residential energy storage. The federal tax credits in Table 3-9 were included in the economic analysis of all private generation forecast scenarios.

Table 3-9 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	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035+
Residential/ Business ITC	< 1000	PV	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	26%	22%	0%
Residential/ Business ITC	< 1000	Energy Storage	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	26%	26%	0%
Residential/ Business ITC	< 1000	Small Wind	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	26%	22%	0%
Business ITC	< 1000	Microturbines	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	26%	22%	0%
Business ITC	< 1000	Reciprocating Engines	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	26%	22%	0%
Business ITC	< 150	Small Hydro (hydropowered dams)	30%	30%	30%											
Business ITC	< 25	Small Hydro (Hydrokinetic pressurized conduits)	30%	30%	30%											
Business ITC	< 1000	Small Hydro				30%	30%	30%	30%	30%	30%	30%	30%	26%	22%	0%

A summary of the state incentives included in the economic analysis are provided below in Table 3-10.

Table 3-10 State Incentives for DERs

STATE	RESIDENTIAL		NON-RESIDENTIAL
Oregon[9]	**PV-Only:** Up to $5,000	**PV + Battery:** Up to $2,500	$0.20/watt up to $20,000
Utah[10]	**PV:** 2022—$800 2023—$400	**Non-PV:** Up to $2,000	Up to 10 percent of the eligible system cost or up to $50,000*
Idaho[11]	Annual maximum of $5,000, and $20,000 over four years**		None
California	None		None
Washington	None		None
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

3.3 Current Private Generation Market

To date, about 99 percent of existing private generation capacity installed in PacifiCorp's service territory is PV or PV + Battery[12]. 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 private generation market in the Company's service territory in the future years of this study. Figure 3-8 shows the current share of private generation capacity by technology in each of PacifiCorp's six-state service territory.

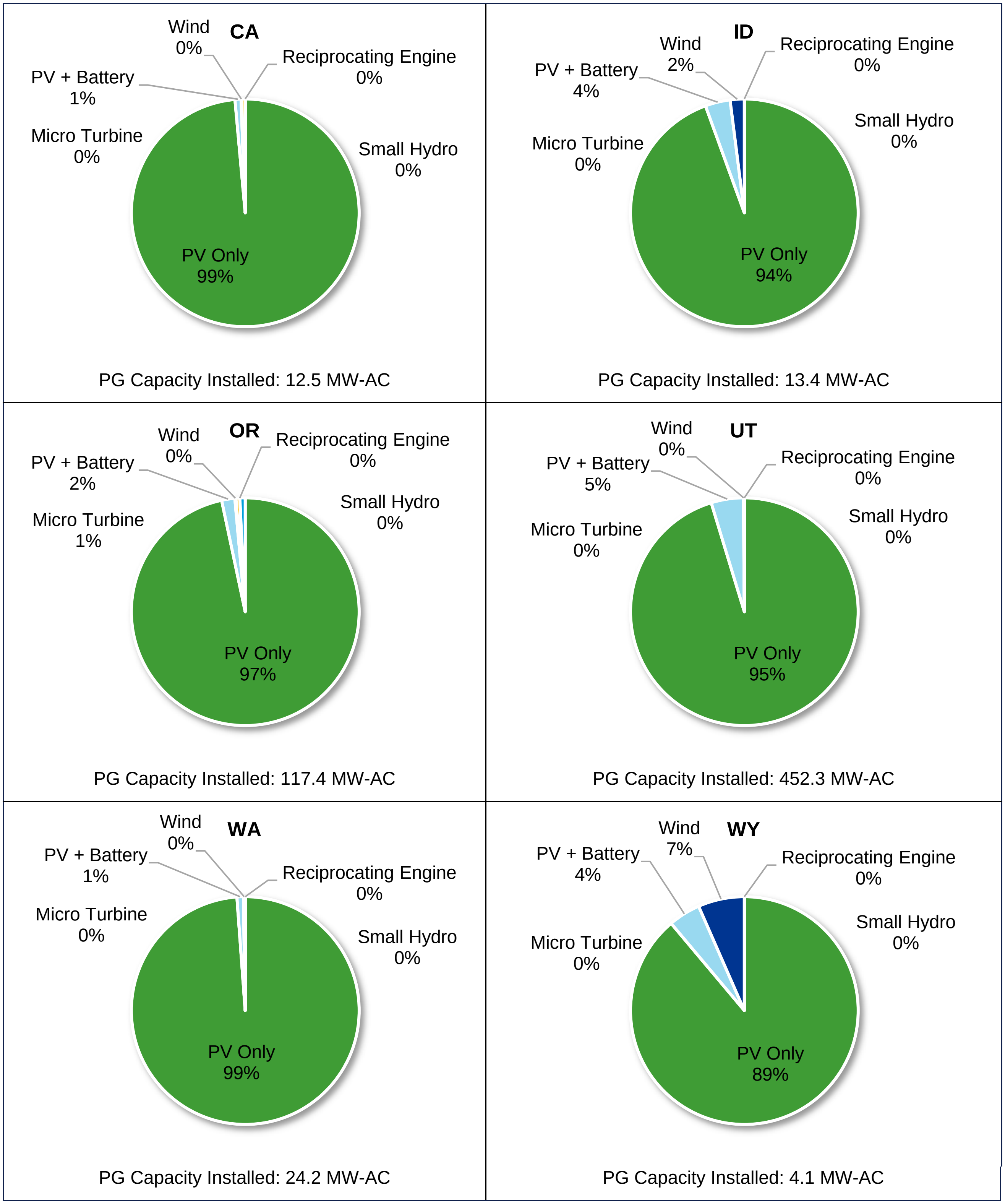
[9] Incentives provided through Energy Trust of Oregon (Solar for Your Home, Solar Within Reach and Solar for Your Business) and Oregon Department of Energy (Solar + Storage Rebate Program for Low-Moderate Income and Non-Income Restricted Homeowners). https://energytrust.org/programs/solar/ https://www.oregon.gov/energy/Incentives/Pages/Solar-Storage-Rebate-Program.aspx

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

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

[12] PacifiCorp private generation interconnection data as of February 2022.

Figure 3-8 Historic Cumulative Installed Private Generation Capacity by Technology, YTD



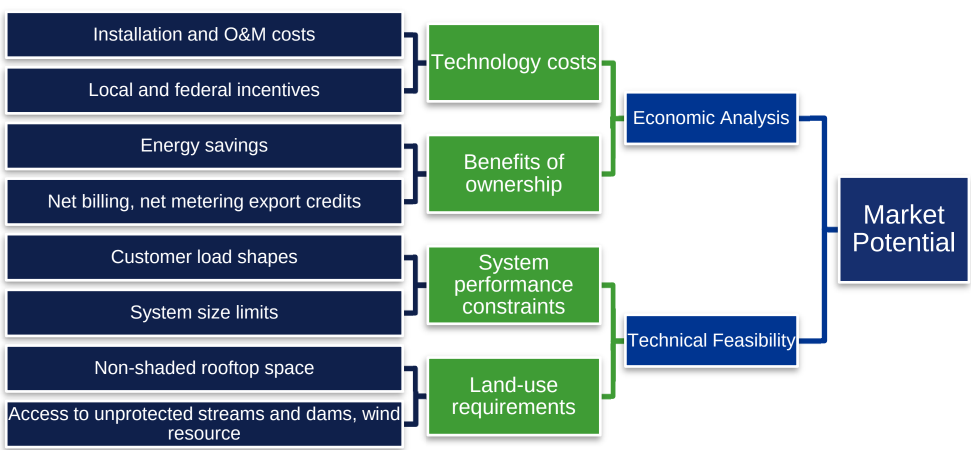
Section 3.4.3 describes in further detail how the historic private generation adoption data is used in the private generation forecast modelling process.

3.4 Forecast Methodology

DNV combined technical feasibility characteristics of the identified PG 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 PG adoption based on technical and economic feasibility and incorporated existing adoption of each PG technology by state and customer segment as an 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 PG technology, or the maximum, feasible, adoption for each technology by sector. These factors included overall PG 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 future penetration of all PG technologies. Figure 3-9 provides a visual representation of how different inputs were used in different portions of the model. Additional detail 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 Private Generation Adoption



3.4.1 Economic Analysis

The economic analysis portion of overall customer adoption was used a key factor in the Bass diffusion model that calculated future PG adoption. DNV used simple payback as the preferred method of estimating economic viability for PG 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 study 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 customer's in Idaho would accrue benefits based on the net billing policy in Utah throughout the study. DNV has been following the ongoing Idaho Public Utilities Commission (PUC) review of Idaho Power Company's (Idaho Power) Value of Distributed Resources (VODER) study filing. Idaho Power's VODER study found that excess power generated by rooftop solar owners is worth less than half of retail rate energy and serves as the basis of Idaho Power's proposal for a new compensation rate structure for solar owners. If approved by the Idaho PUC, Idaho Power's proposed compensation rate structure would more closely resemble the current net billing structure in place in Utah[13] and DNV assumed PacifiCorp would implement a similar rate structure in their Idaho territory.

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 PG 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 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 3-11 below.

Table 3-11 PG Forecast Economic Analysis Inputs

INPUT TYPE	COST / BENEFIT CATEGORY	SOURCE
TECHNOLOGY COST DATA – INSTALLED COST	PG cost data compiled in $/kW (AC & DC) – used in determining year one installed system costs	DNV
TECHNOLOGY COST DATA – ANNUAL O&M	PG fixed ($/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 2022
TECHNOLOGY GENERATION PROFILES	Hourly generation profiles for each PG 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

[13] As of December 19, 2022, the Idaho Power VODER study has been approved by the Idaho PUC. https://puc.idaho.gov/Fileroom/PublicFiles/ELEC/IPC/IPCE2222/OrdNotc/20221219Final_Order_No_35631.pdf

INPUT TYPE	COST / BENEFIT CATEGORY	SOURCE
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	PG 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 ATB
CUSTOMER & LOAD FORECASTS	Individual customer count and load (kWh) forecasts by 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 2022

DNV calculated simple payback for each PG 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 (2023 – 2035). These payback results were combined with technical feasibility by customer segment and integrated into the bass diffusion adoption model to determine annual PG penetration throughout PacifiCorp's territory.

3.4.2 Technical Feasibility

The maximum amount of technical feasible capacity of private generation was determined individually for each technology considered in the private 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 PG 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[14]
- Building rooftop hosting area and suitability for solar PV[15]
- Wind resource potential data by state[16]

[14] 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.

[15] 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.

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

3.4.3 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[17]

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

<u>Where:</u>

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

m is the ultimate market potential

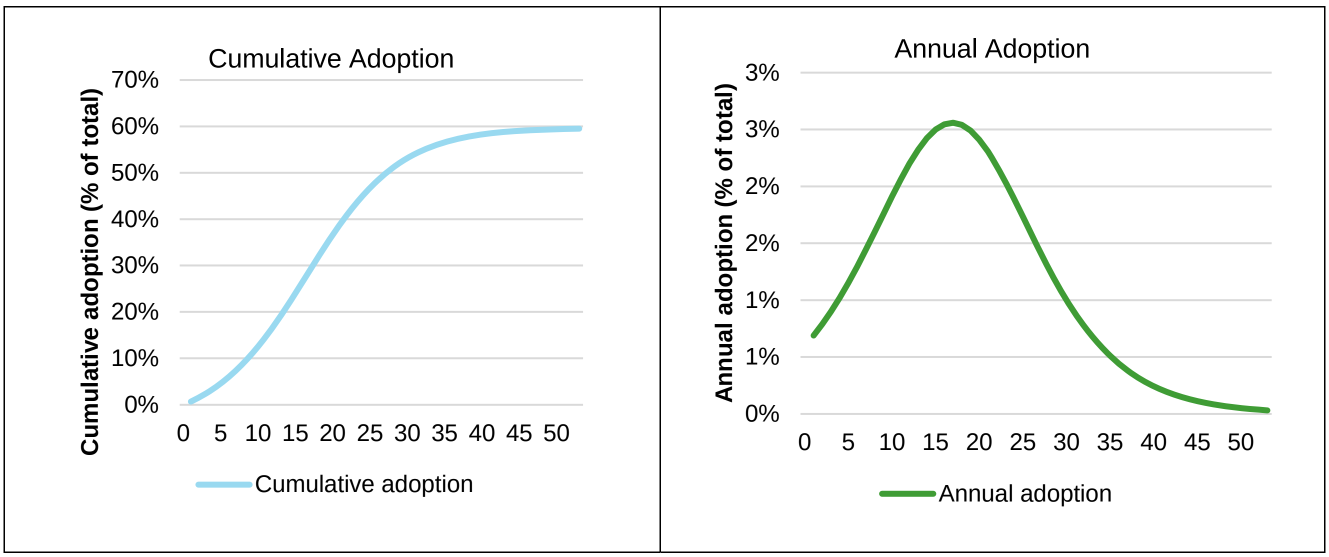
p is the coefficient of innovation

q is the coefficient of imitation

t is time in years

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

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,

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

following Sigrin and Drury's[18] 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 levels of PG 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 3-12 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 state, so we assumed average propensity to adopt for wind, small hydro, reciprocating engines and microturbines.

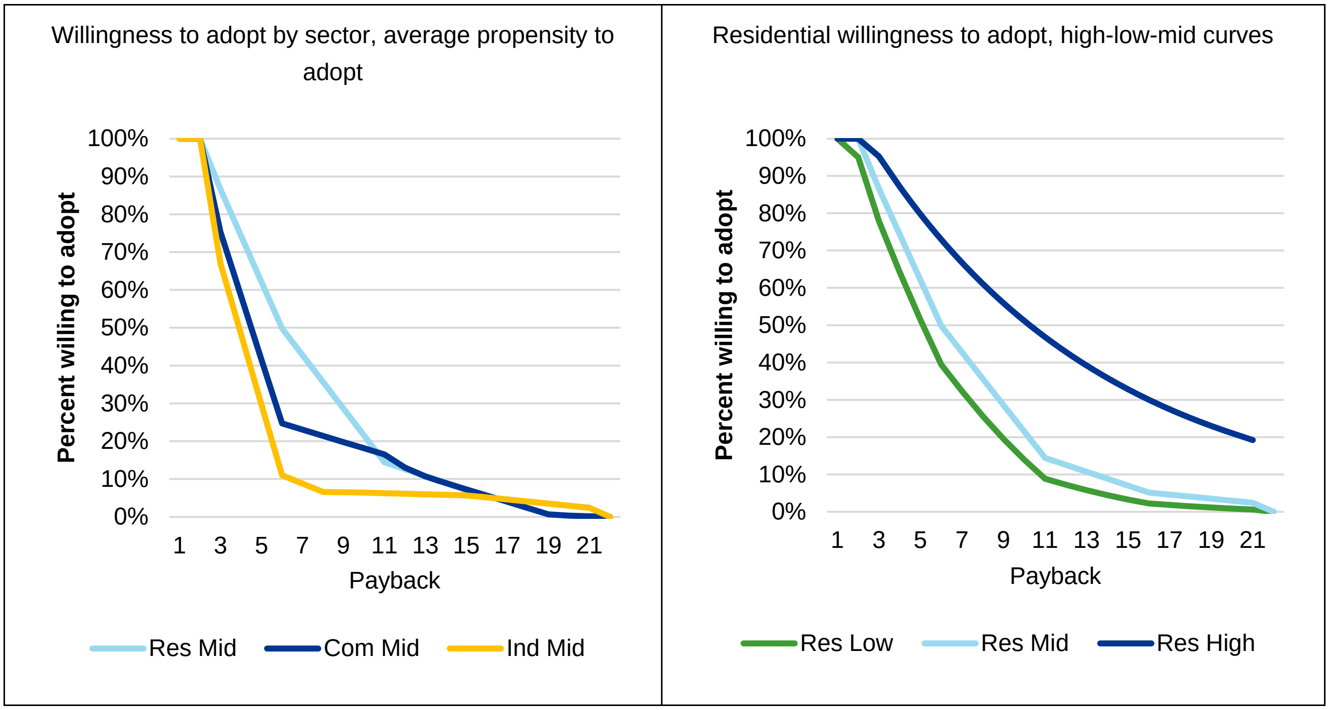
Table 3-12 Solar Willingness-to-Adopt Curve used by State and Sector

AVERAGE PROPENSITY TO ADOPT	HIGH PROPENSITY TO ADOPT	LOW PROPENSITY TO ADOPT
• California residential, commercial, irrigation • Idaho residential • Oregon residential • Washington all sectors	• Utah all sectors • Oregon commercial, industrial, irrigation	• Wyoming all sectors • Idaho commercial, industrial, irrigation • California industrial

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. The right-hand chart in Figure 3-11 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.

[18] 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 Willingness to Adopt Based on Technology Payback



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 2023.

The *p* and *q* parameters of the Bass diffusion curves were calibrated so that the predicted cumulative adoption from t_0 through 2021 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 were 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 still in the very early phases of adoption, while other markets are more mature. Our forecast of annual adoption reflects all of these differences.

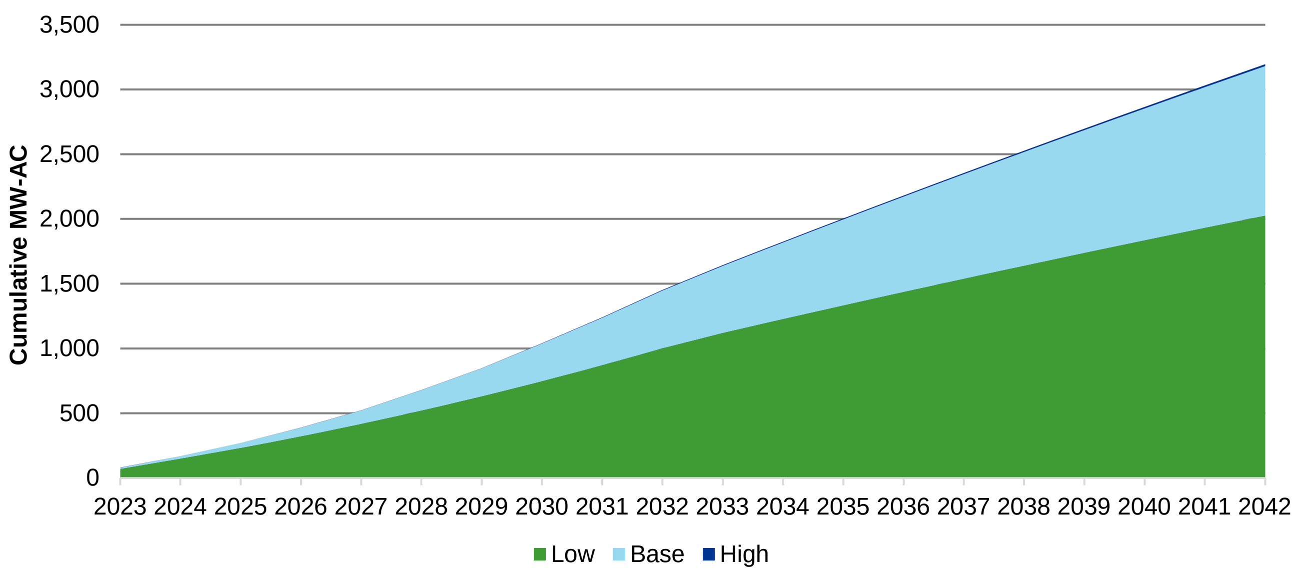
4 RESULTS

In the base case scenario, DNV estimates 3,181 MW of new private generation capacity will be installed in PacifiCorp's service territory over the nest twenty years (2023-2042). Figure 4-1 shows the relationship between the base case and low and high case scenarios. The low case scenario estimates 2,028 MW of new capacity over the 20-year forecast period—compared to 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 3,196 MW of new private generation capacity installed by 2042.

Table 4-1 Cumulative Adopted Private Generation Capacity by 2042, by Scenario

SCENARIO	CUMULATIVE CAPACITY (2042 MW-AC)
Base	3,181
Low	2,028
High	3,196

Figure 4-1 Cumulative New Private Generation Capacity Installed by Scenario (MW-AC), 2023-2042



The sensitivity analysis showed a much greater margin of uncertainty on the low side than the high side. The Inflation Reduction Act of 2022 (IRA) extends tax credits that for private generation that create very 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. The low case assumed higher technology costs and lower retail electricity rates than the other cases, reducing the economic appeal of private generation despite incentives being unchanged. The low case forecast is 36% less than the base case, while the high case cumulative installed capacity forecasted over the 20-year period is just 0.5% greater than the base case.

Figure 4-2 Cumulative New Capacity Installed by Technology (MW-AC), 2023-2042, Base Case

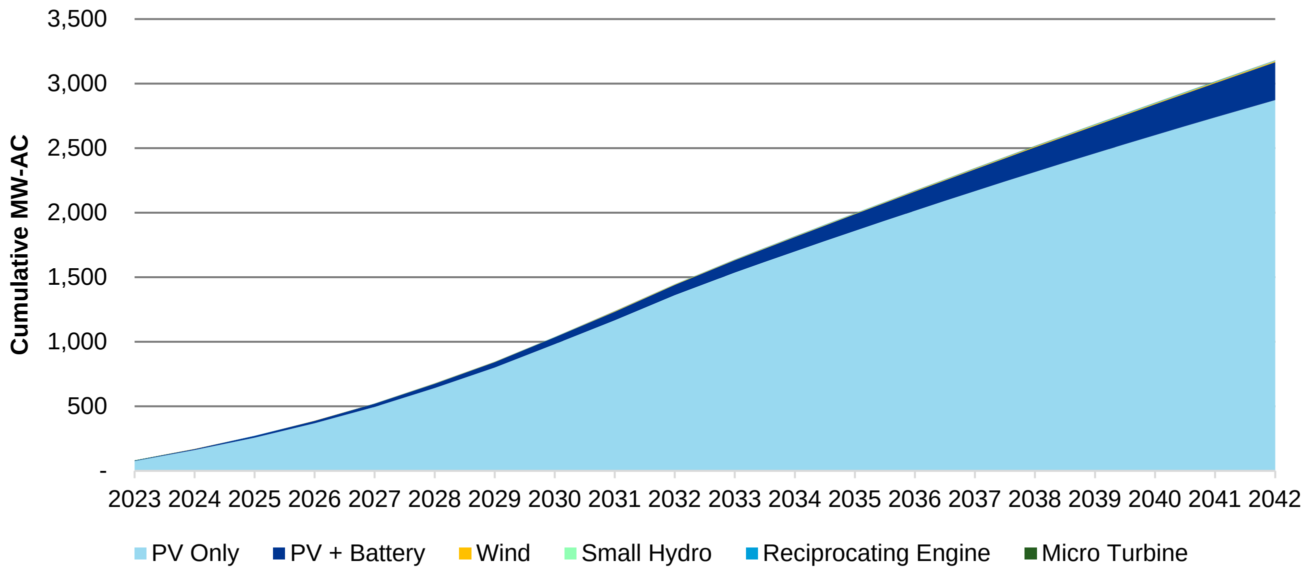


Figure 4-3 Cumulative New Capacity Installed by Technology (MW-AC), 2023-2042, Low Case

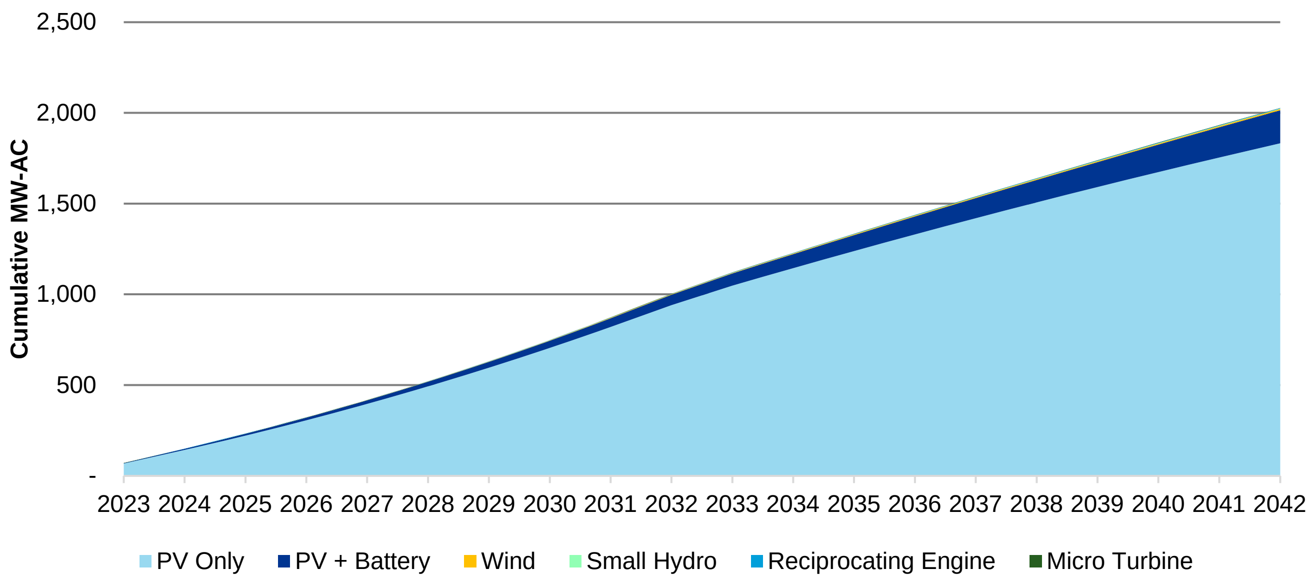
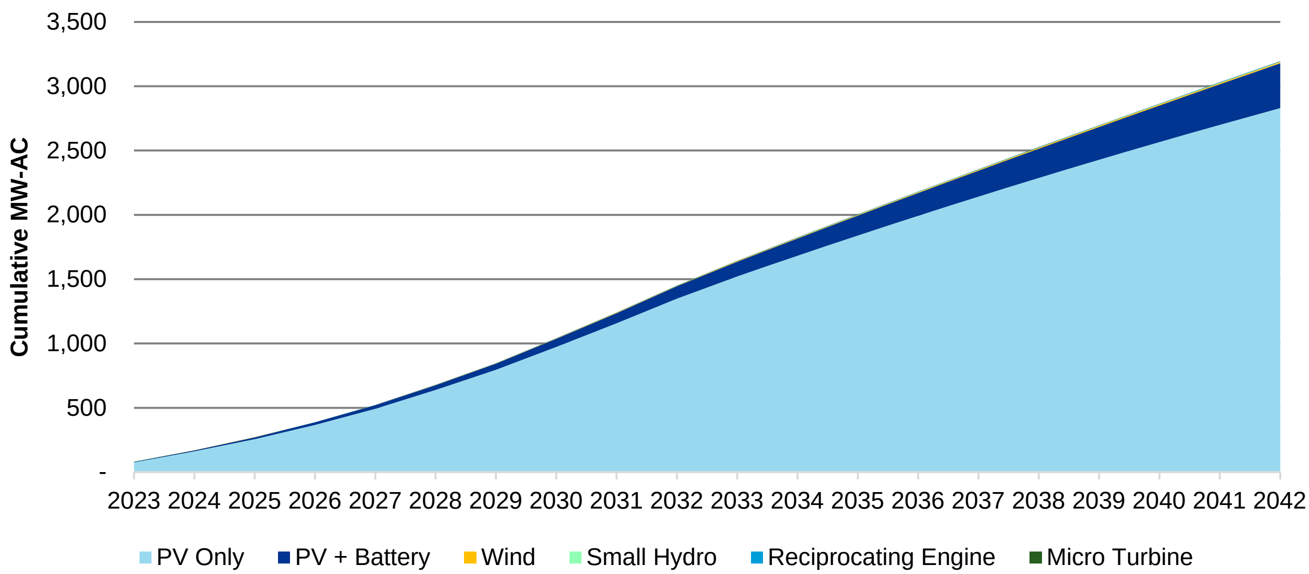


Figure 4-4 Cumulative New Capacity Installed by Technology (MW-AC), 2023-2042, High Case



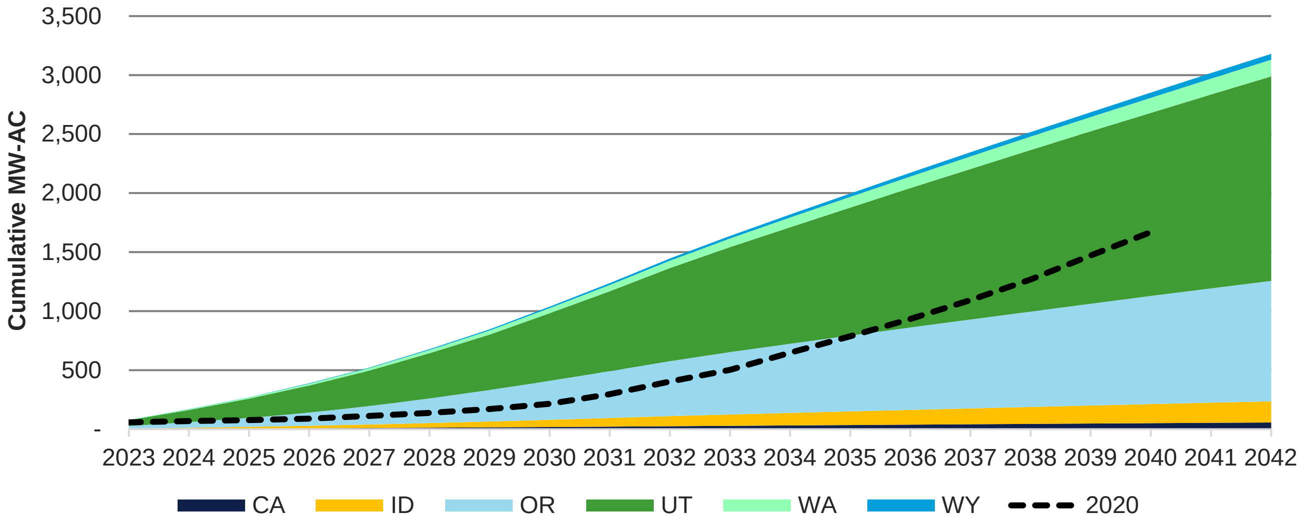
4.1 Generation Capacity Results by State

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 states' projected private 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.

Figure 4-5 shows the base case forecast by state, compared to the previous (2020) study's total base case forecast[19]. 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. The base scenario estimates approximately 1,447 MW of new capacity will be installed over the next 10 years in PacifiCorp's territory—55% of which is in Utah, 32% in Oregon, and 6% in Idaho. Since the 2020 study, the federal Investment Tax Credit (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 follow 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.

[19] Cumulative capacity is adjusted to account for the difference in the forecast starting years (2021 in the previous study, versus 2023 in this study). Source: Navigant. 2020. "Private Generation Long-Term Resource Assessment (2021-2040)"

Figure 4-5 Cumulative New Capacity Installed by State (MW-AC), 2023-2042, Base Case



4.1.1 California

Customers in PacifiCorp's service territory in northern California are projected to install about 57 MW of new private generation capacity over the next two decades in the base case. The 20-year high projection is about 1% greater than the base case and the low projection is 24% less than the base case, or 57.4 MW and 43 MW, respectively.

California does not currently have any state incentives available for private generation, and uses a net billing structure for DER compensation. The residential sector has the largest share of the private generation capacity, ranging from 59% in the low case to 67% in the high and base cases. The next largest share of the capacity is forecasted in the commercial sector, ranging from 31% in the low case to 24% in the base and high cases.

Figure 4-6 Cumulative New Private Generation Capacity Installed by Scenario (MW-AC), California, 2023-2042

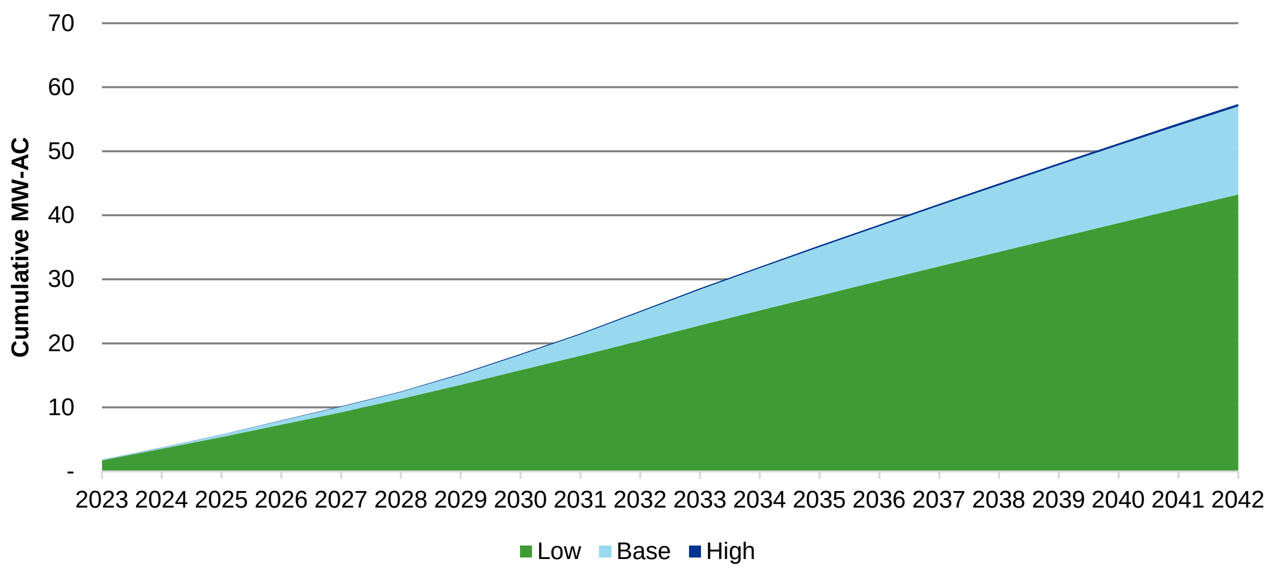


Figure 4-7 Cumulative New Capacity Installed by Technology (MW-AC), California Base Case, 2023-2042

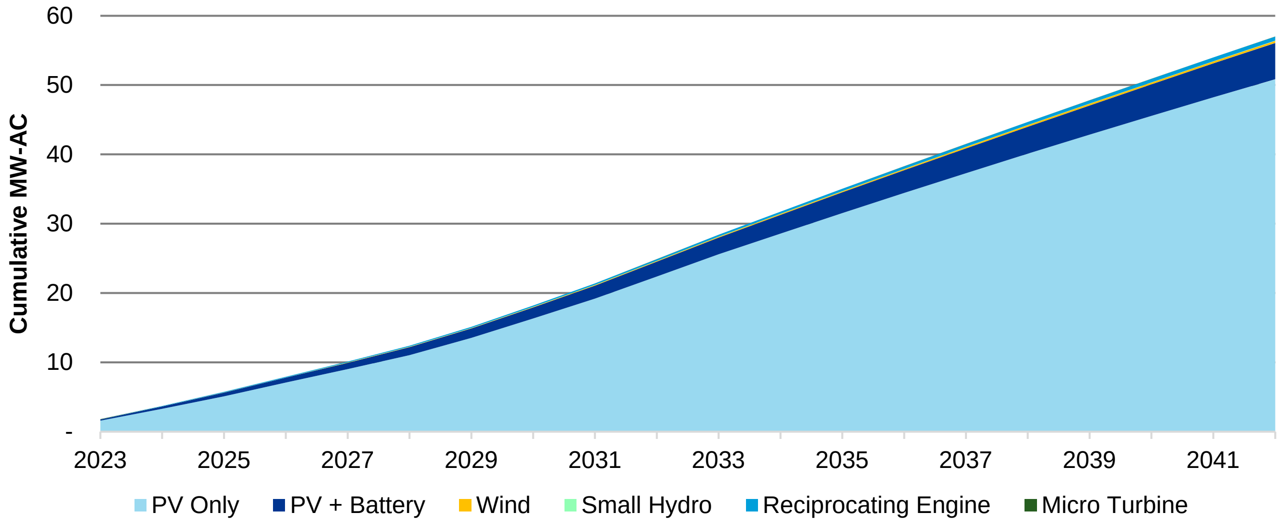


Figure 4-8 Cumulative New Capacity Installed by Technology (MW-AC), California Low Case, 2023-2042

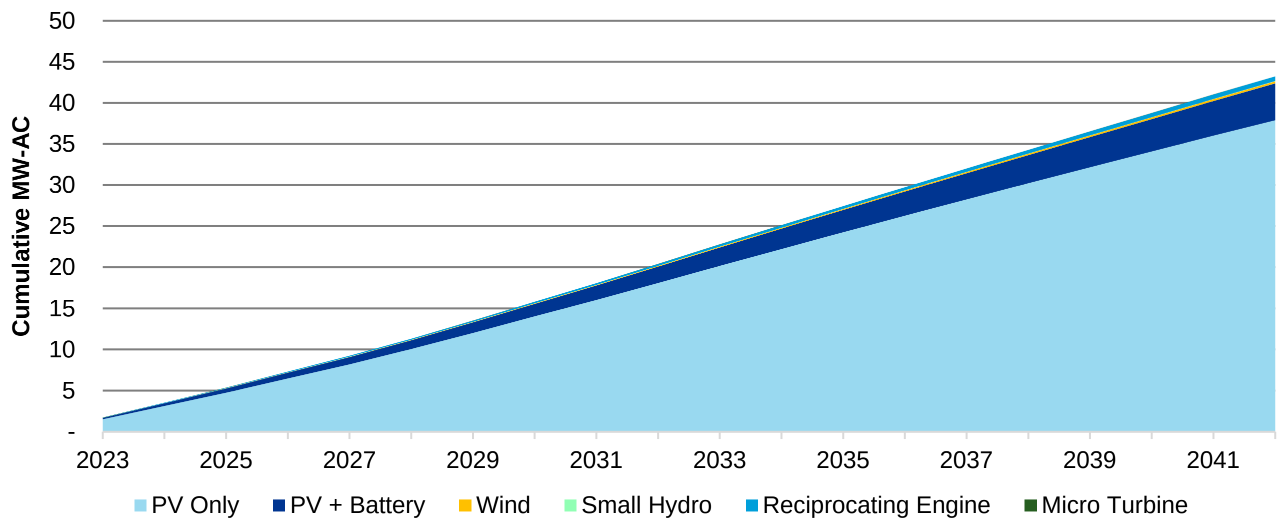
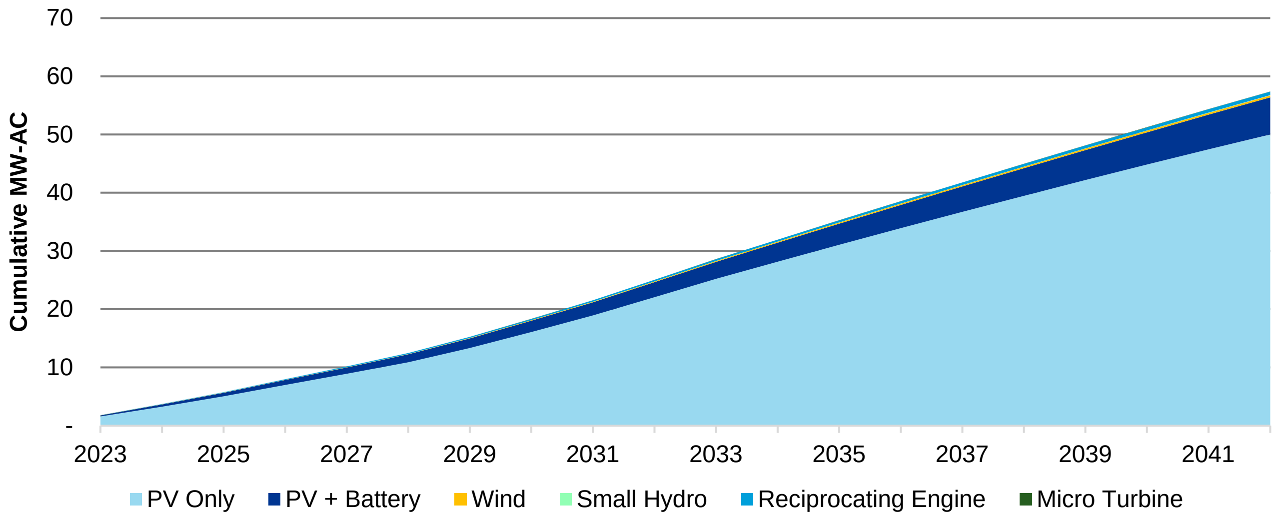


Figure 4-9   Cumulative New Capacity Installed by Technology (MW-AC), California High Case, 2023-2042

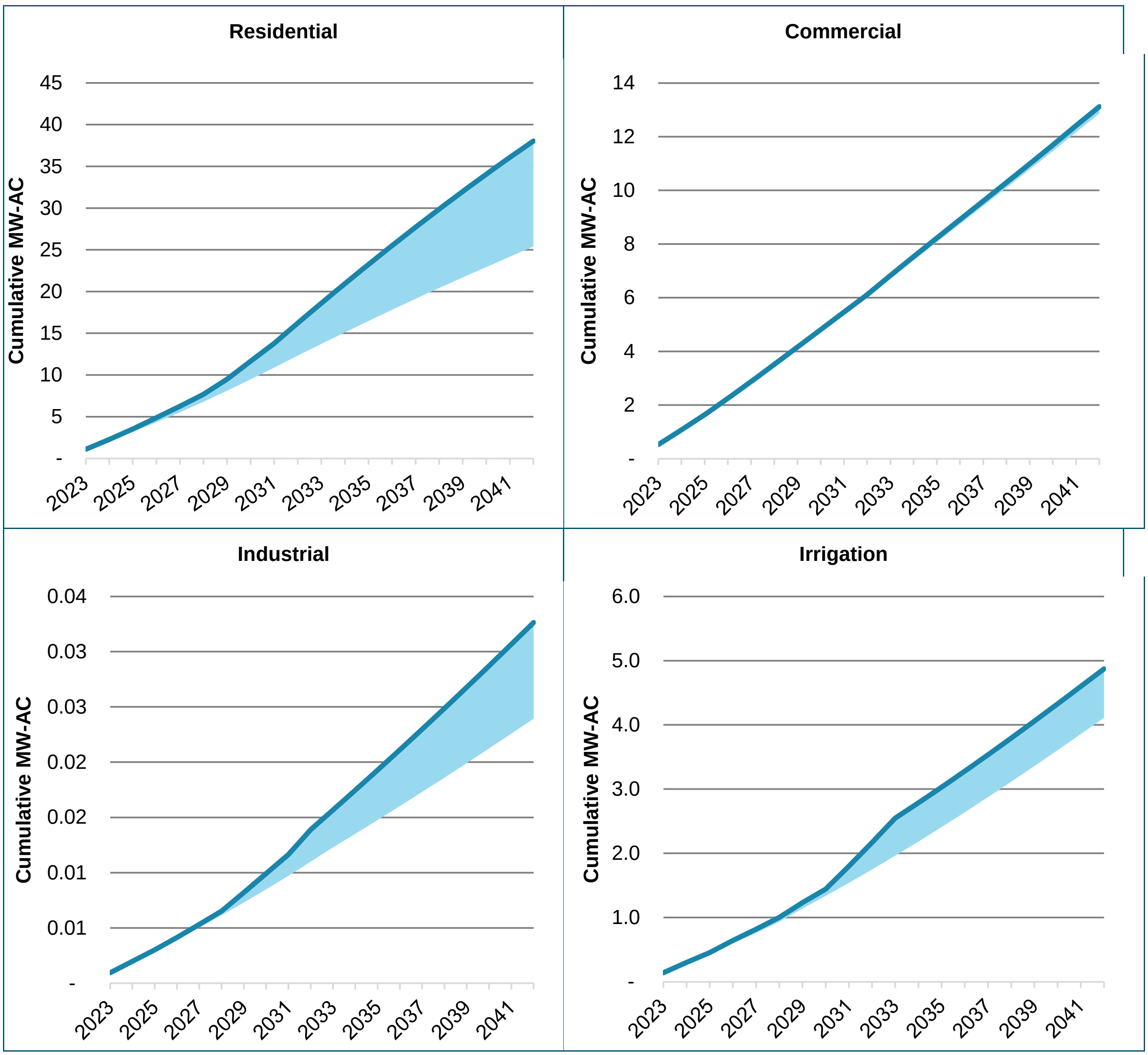


4.1.1.1 California PV Adoption by Sector

The impact of the three different scenarios on PV adoption by sector is shown in the following charts, which present 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 8% of total PV capacity in 2042 for the high case. The share of PV + Battery capacity is about 20% of total commercial PV capacity in 2042 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. The industrial sector did not have any PV + Battery adoption forecasted.

Figure 4-10 Cumulative New PV Capacity Installed by Sector Across All Scenarios, California, 2023-2042

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 179 MW of new private generation capacity over the next two decades in the base case. The 20-year high projection is about 1% greater than the base case and the low projection is 33% less than the base case, or 181 MW and 121 MW, respectively.

Idaho has a fairly generous 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 3.2.5. DNV assumed Idaho would use the same net billing structure for DER compensation as Utah for the study period (2023-2042). The residential sector has the largest share of the private generation capacity, ranging from 54% in the base and high cases to 48% in the low case. The next largest share of the capacity is forecasted in the commercial sector, ranging from 38% in the low case to 34% in the base and high cases.

Figure 4-11 Cumulative New Private Generation Capacity Installed by Scenario (MW-AC), Idaho, 2023-2042

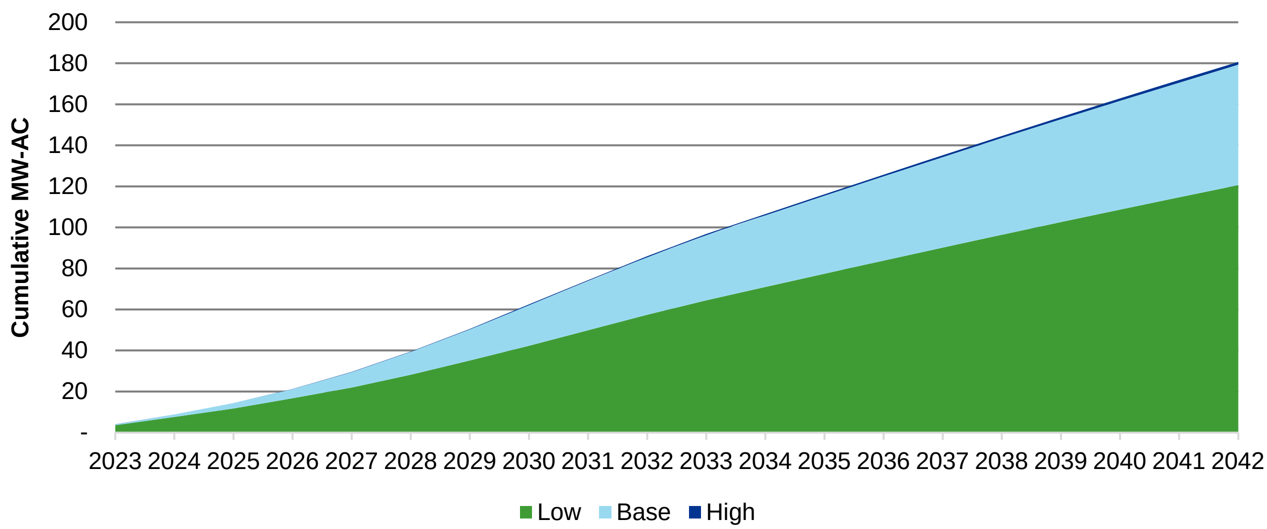


Figure 4-12 Cumulative New Capacity Installed by Technology (MW-AC), Idaho Base Case, 2023-2042

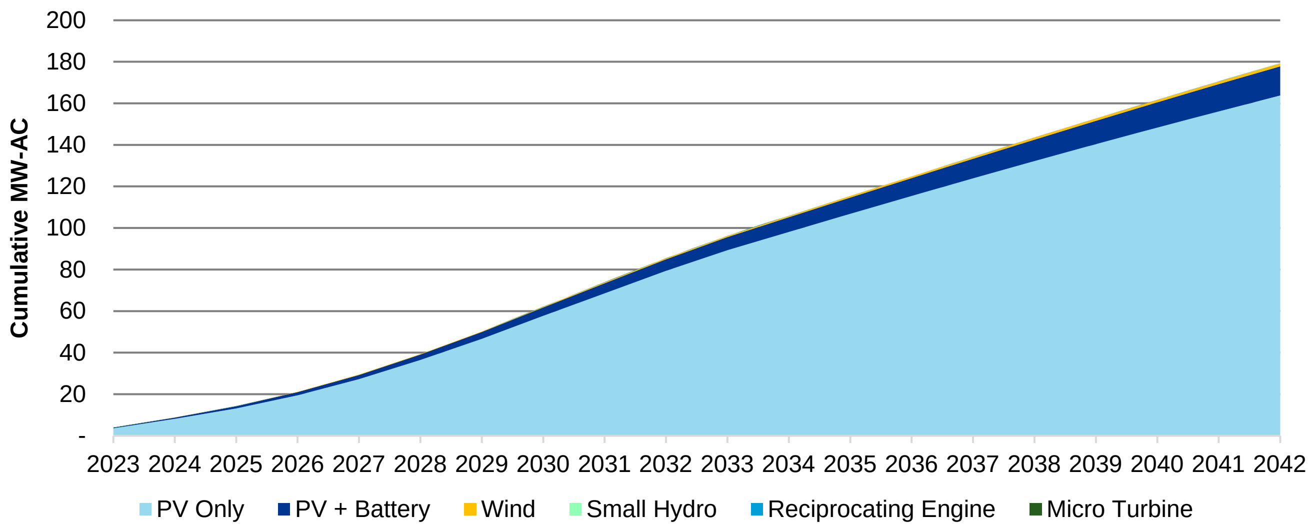


Figure 4-13 Cumulative New Capacity Installed by Technology (MW-AC), Idaho Low Case, 2023-2042

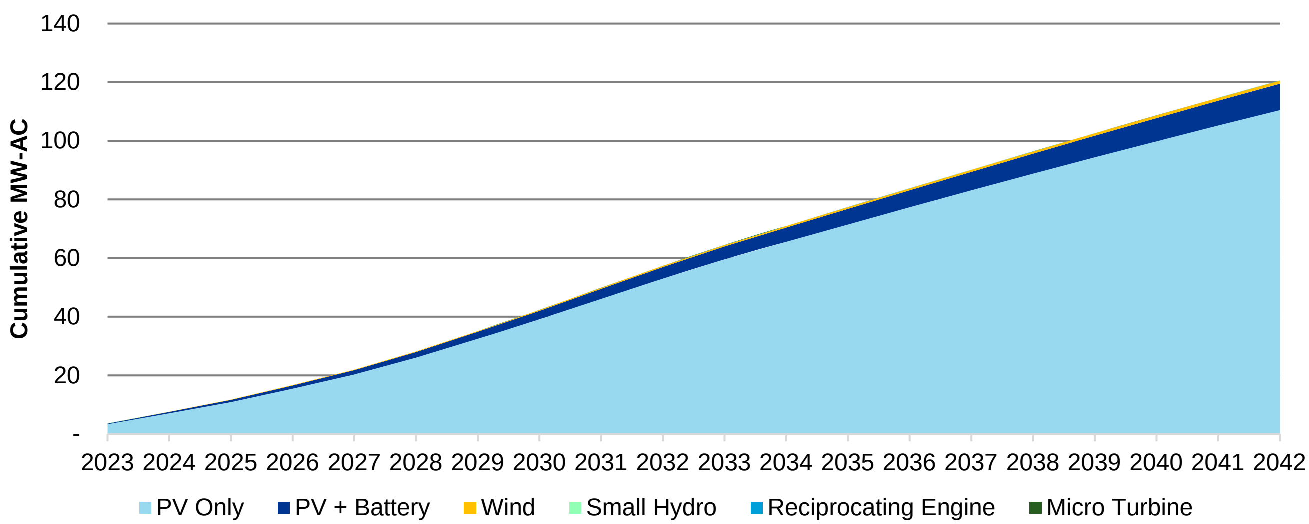
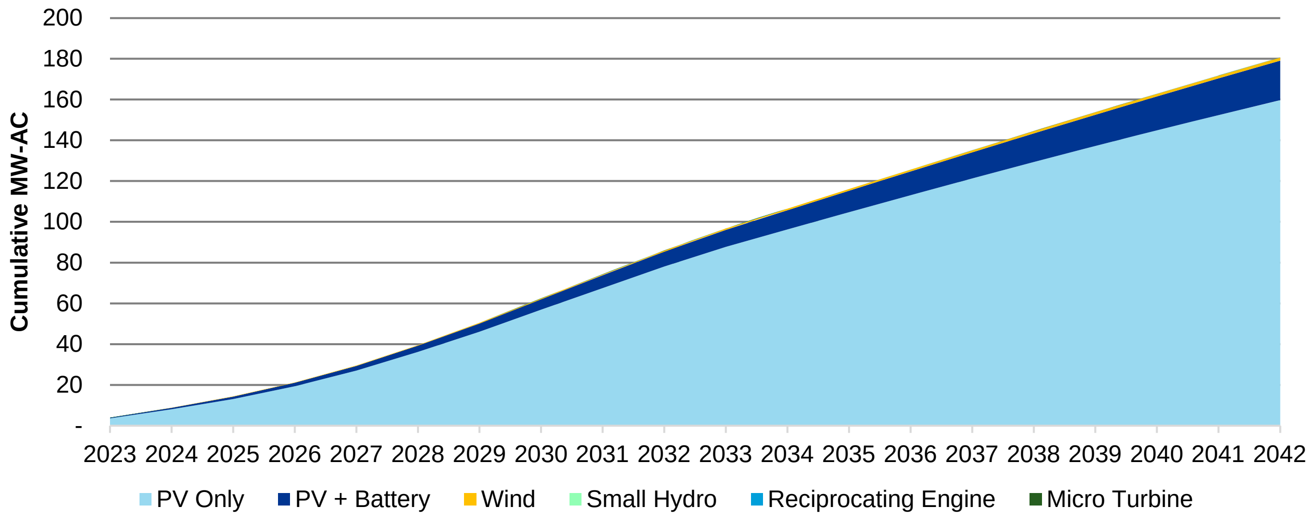


Figure 4-14 Cumulative New Capacity Installed by Technology (MW-AC), Idaho High Case, 2023-2042

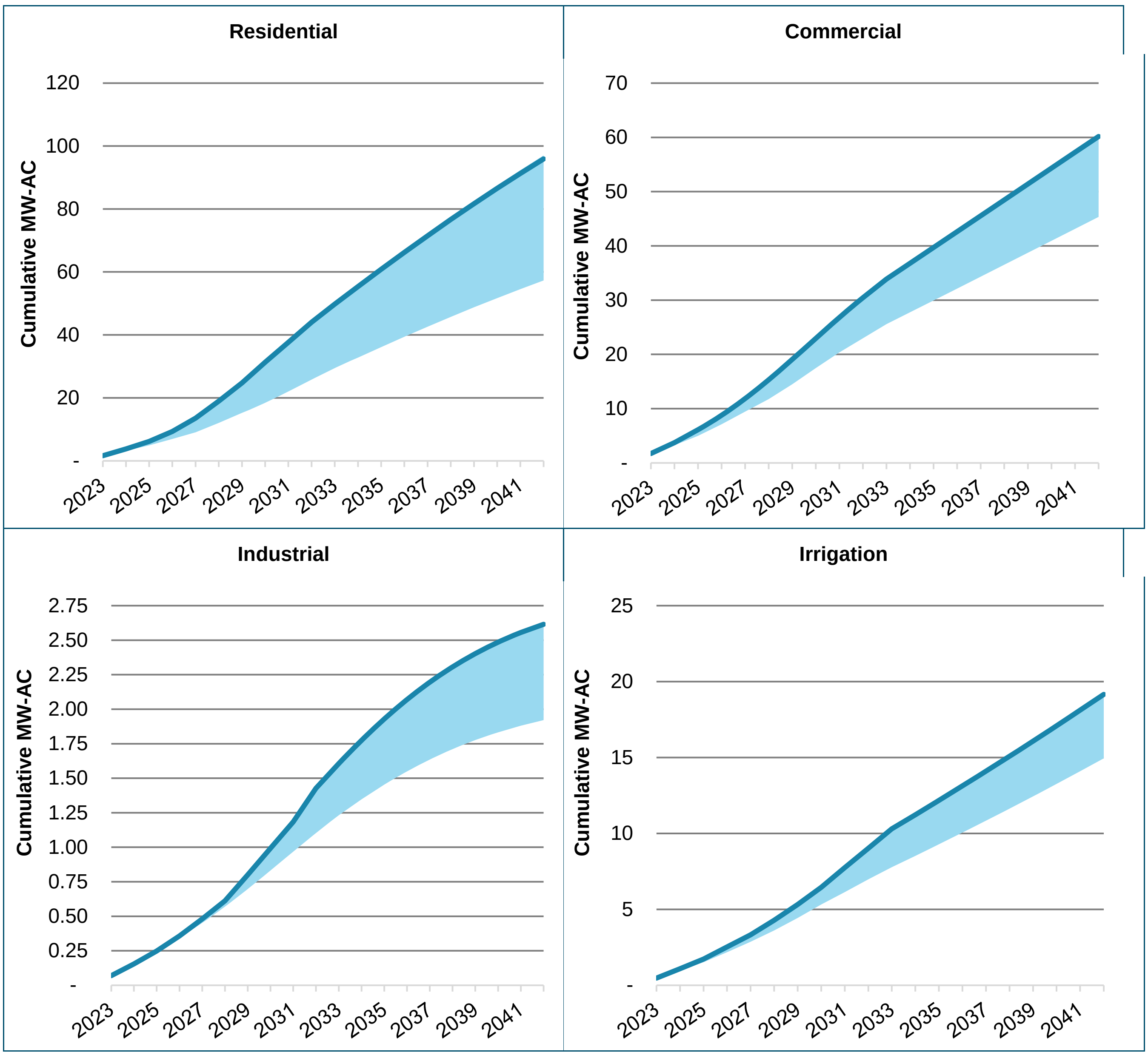


4.1.2.1 Idaho PV Adoption by Sector

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 4-15 Cumulative New PV Capacity Installed by Sector Across All Scenarios, Idaho, 2023-2042

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 1,020 MW of new private generation capacity over the next two decades in the base case. The 20-year high projection is slightly higher than the base case and the low projection is 39% less than the base case, or 1,022 MW and 623 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. Both the Oregon DOE and ETO provide increased incentives for households with low- to moderate-incomes. Oregon is the only state in PacifiCorp's territory, at this time, that provides different incentives for residential customers by income level. As the residential private generation forecast was not segmented by income level, DNV had to develop a single incentive value for the economic analysis. In order to incorporate the higher incentives for the income-qualified customers, DNV developed a weighted average incentive for Oregon residential customers. The income-level weights were calculated from the demographic data of the pool of potential adopters for each technology, in order to best represent the total technology cost (net of incentives) that Oregon residential customers are making their purchasing decisions based off of. Annual household income was included in the census-tract-level demographic data that DNV incorporated into PacifiCorp's Oregon Distribution System Plan circuit-level private generation forecast. While the higher incentive for income-qualified customers provides a boost to customer economics, it does not address the other larger barriers to adoption, such as lack of access to capital and home ownership status. Therefore representation of low- to moderate-income households in the pool of potential adopters for the PV and PV + Battery technologies is still very low.

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 4-16 Cumulative New Private Generation Capacity Installed by Scenario (MW-AC), Oregon, 2023-2042

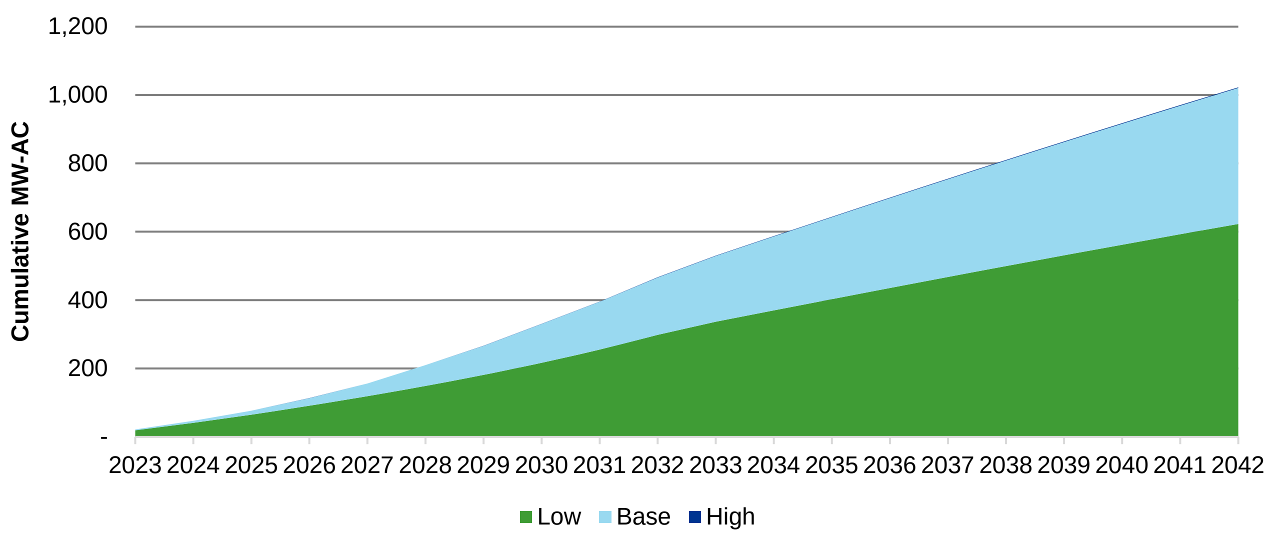


Figure 4-17 Cumulative New Capacity Installed by Technology (MW-AC), Oregon Base Case, 2023-2042

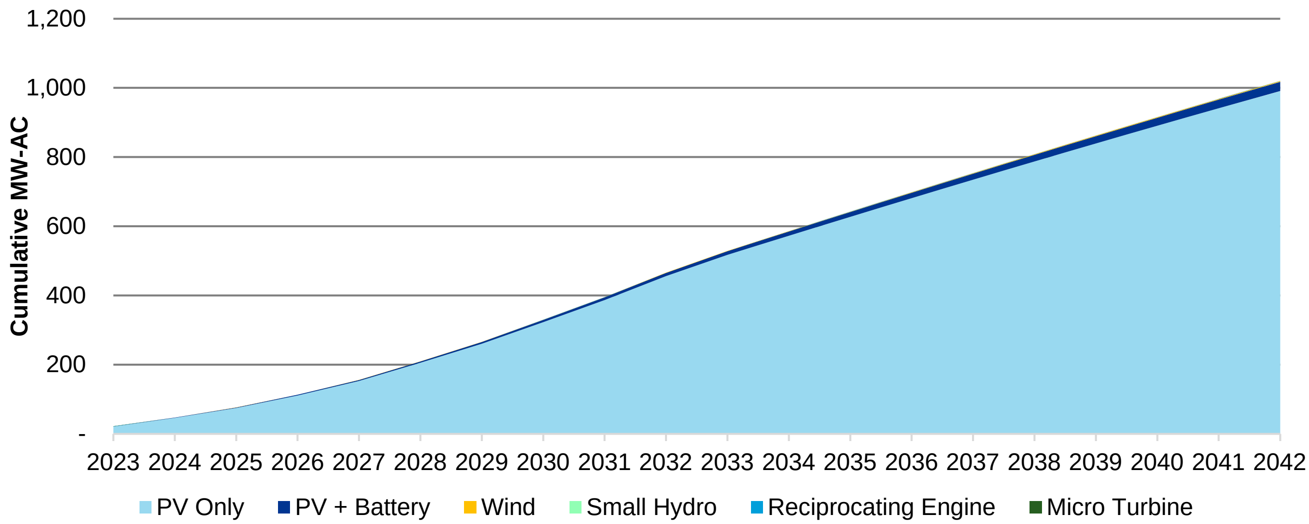


Figure 4-18 Cumulative New Capacity Installed by Technology (MW-AC), Oregon Low Case, 2023-2042

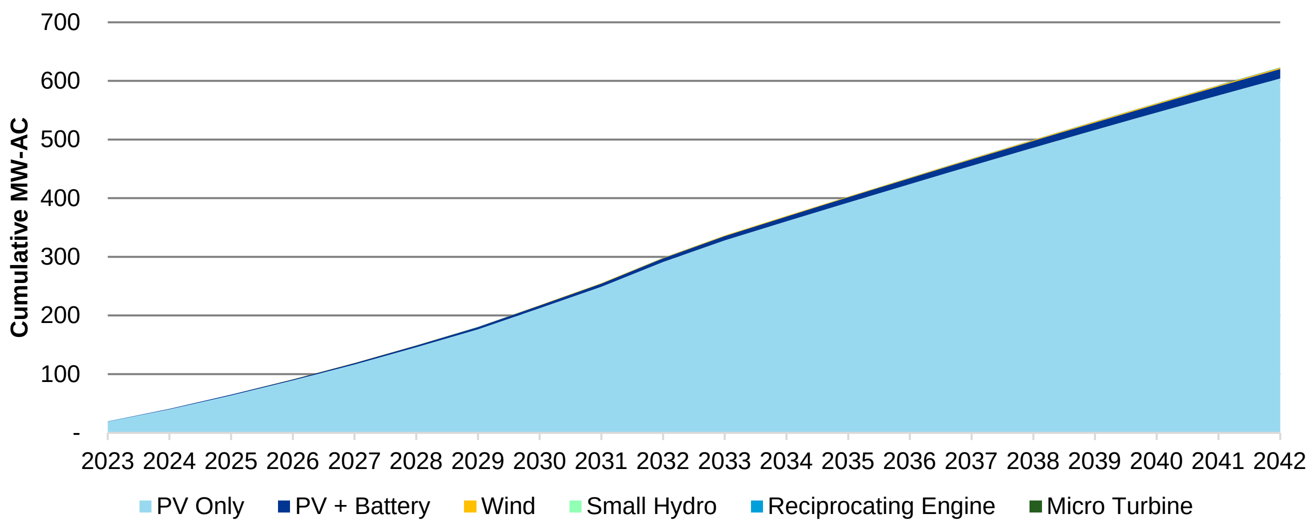
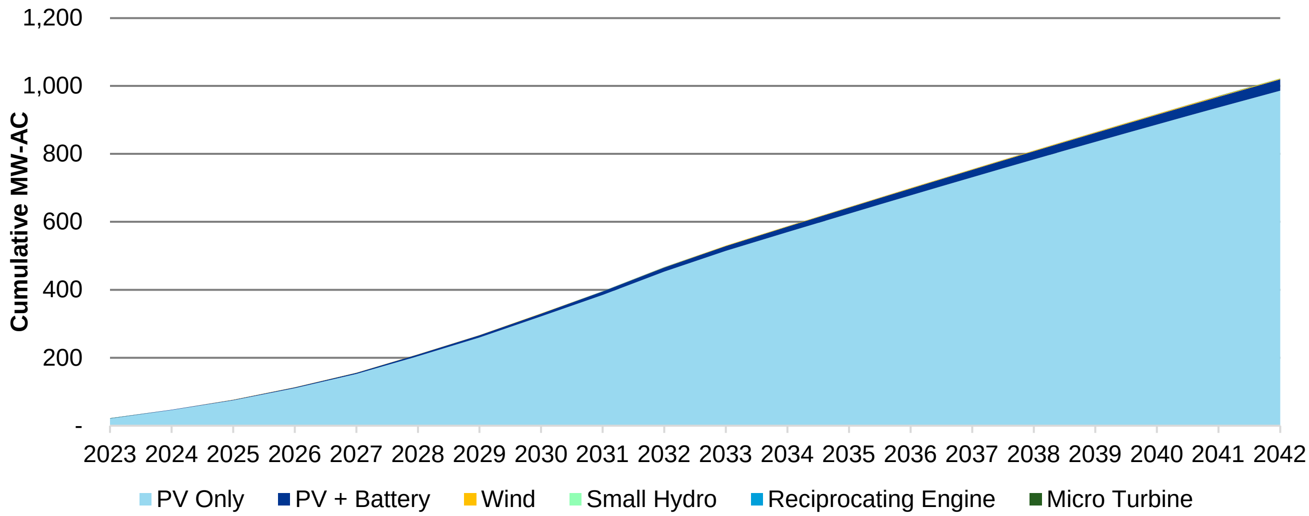


Figure 4-19 Cumulative New Capacity Installed by Technology (MW-AC), Oregon High Case, 2023-2042

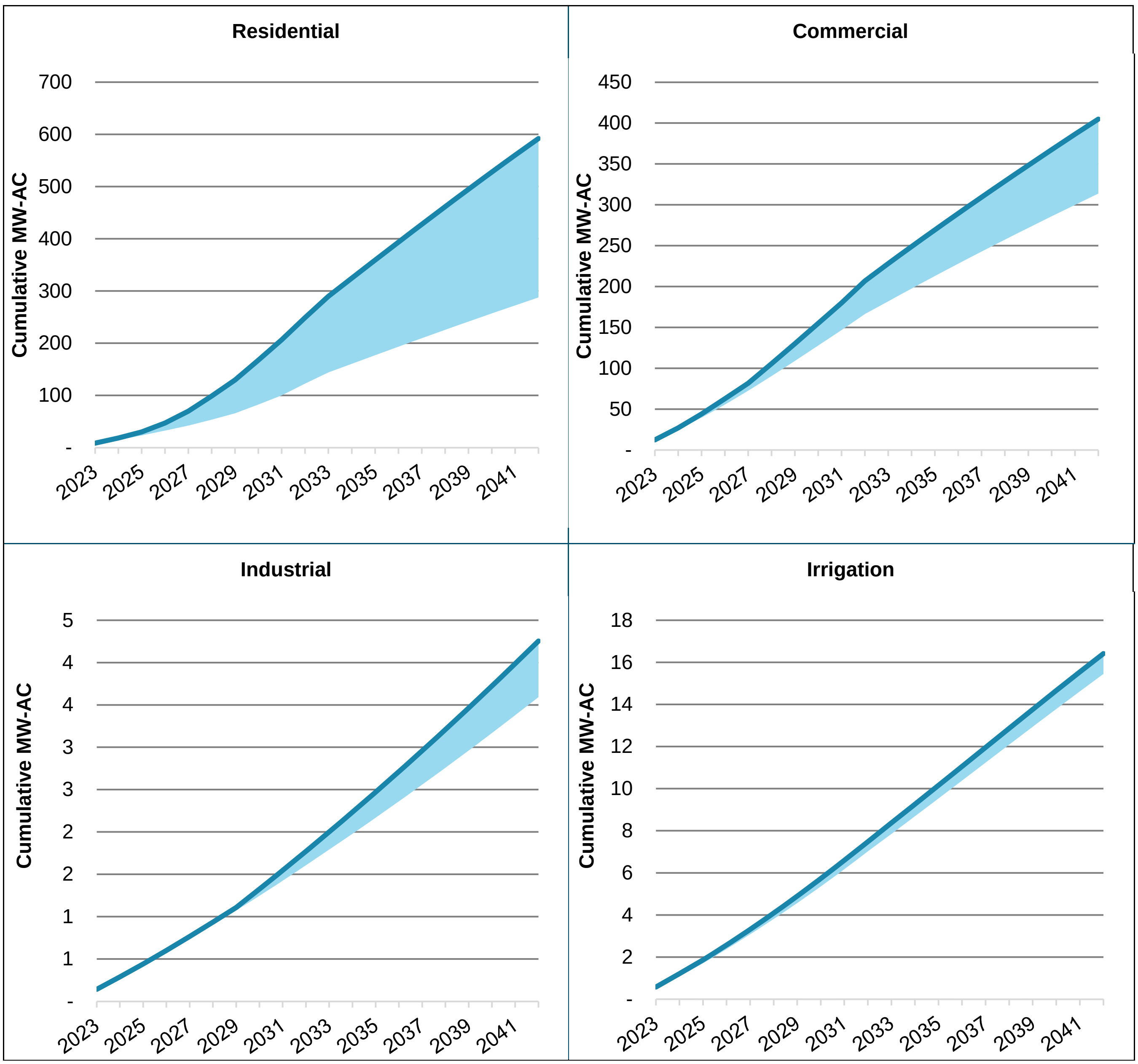


4.1.3.1 Oregon PV Adoption by Sector

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 did not have any PV + Battery adoption forecasted.

Figure 4-20 Cumulative New PV Capacity Installed by Sector Across All Scenarios, Oregon, 2023-2042

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 1,733 MW of new private generation capacity over the next two decades in the base case. The 20-year high projection is less than 1% greater than the base case and the low projection is 34% less than the base case, or 1,742 MW and 1,140 MW, respectively.

Utah has an incentive program for residential and business customers, but the residential PV incentive expires in 2023. The incentives are provided through through Utah Office of Energy Development Renewable Energy Systems Tax Credit, discussed in section 3.2.5. DNV assumed Utah's net billing policies would remain in place throughout the study. In all cases, the commercial sector has the largest share of the private generation capacity forecasted—ranging from 50% to 58% in the high and low cases, respectively. The residential sector represents the 42% of the capacity forecast in the high and base scenarios, but only 33% in the low case.

Figure 4-21 Cumulative New Private Generation Capacity Installed by Scenario (MW-AC), Utah, 2023-2042

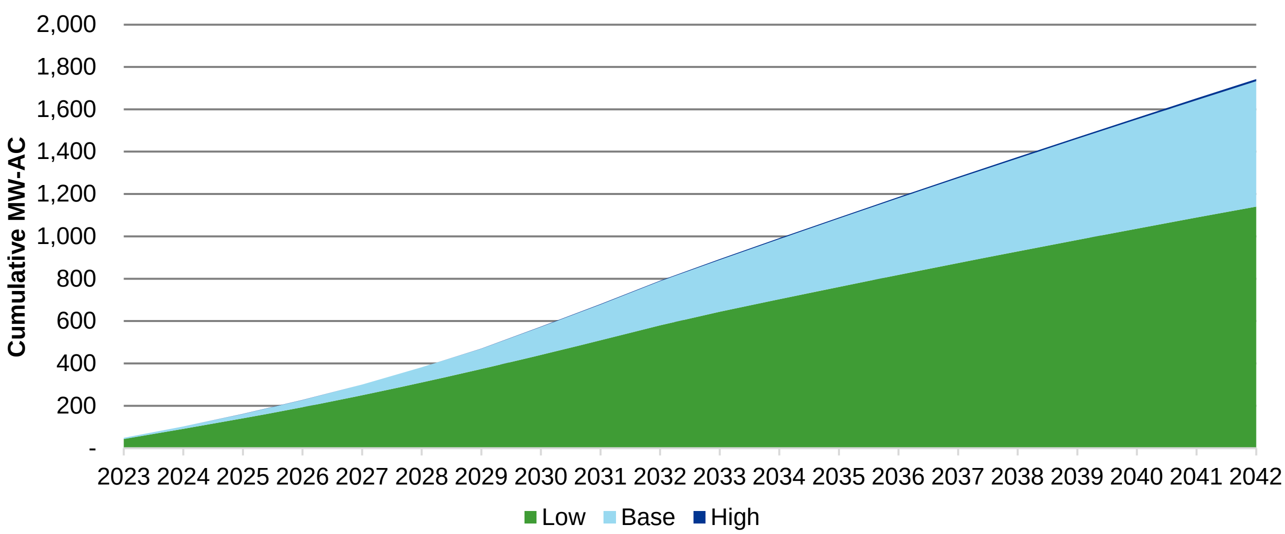


Figure 4-22 Cumulative New Capacity Installed by Technology (MW-AC), Utah Base Case, 2023-2042

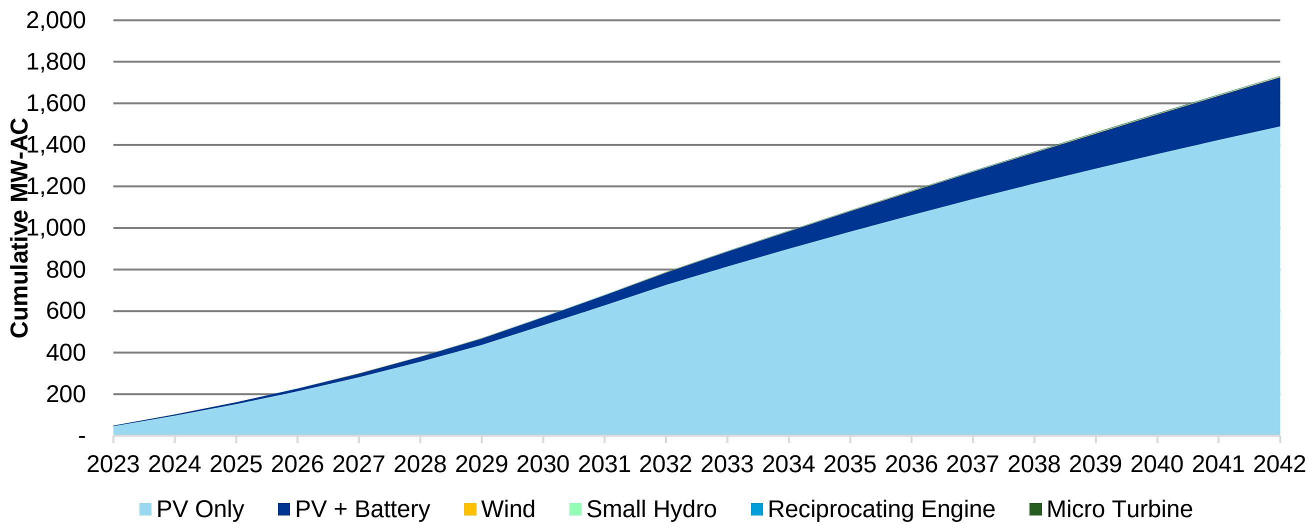


Figure 4-23 Cumulative New Capacity Installed by Technology (MW-AC), Utah Low Case, 2023-2042

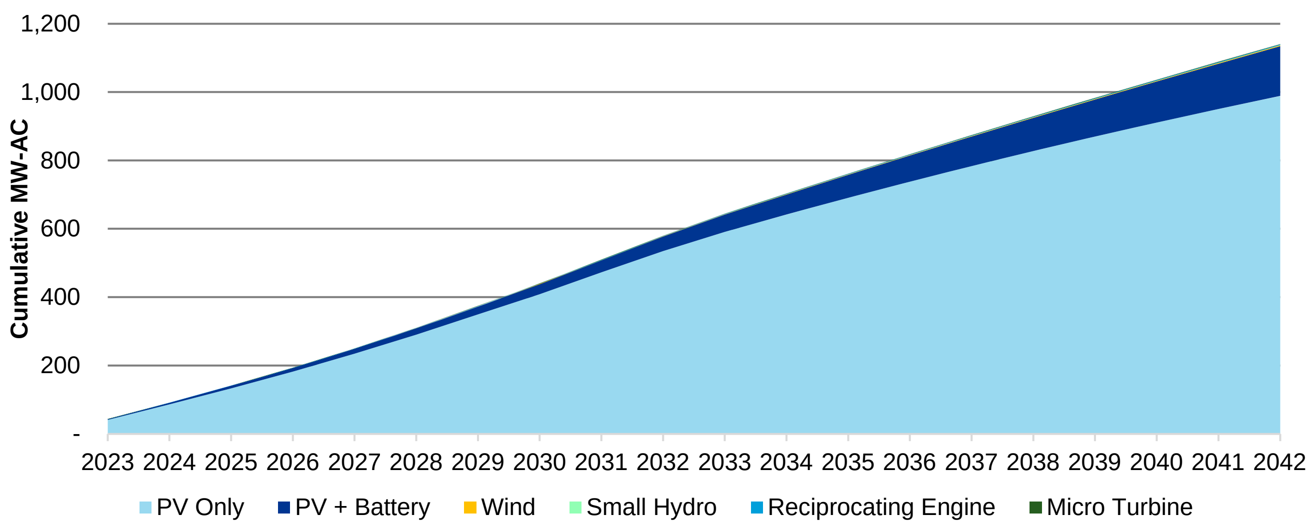
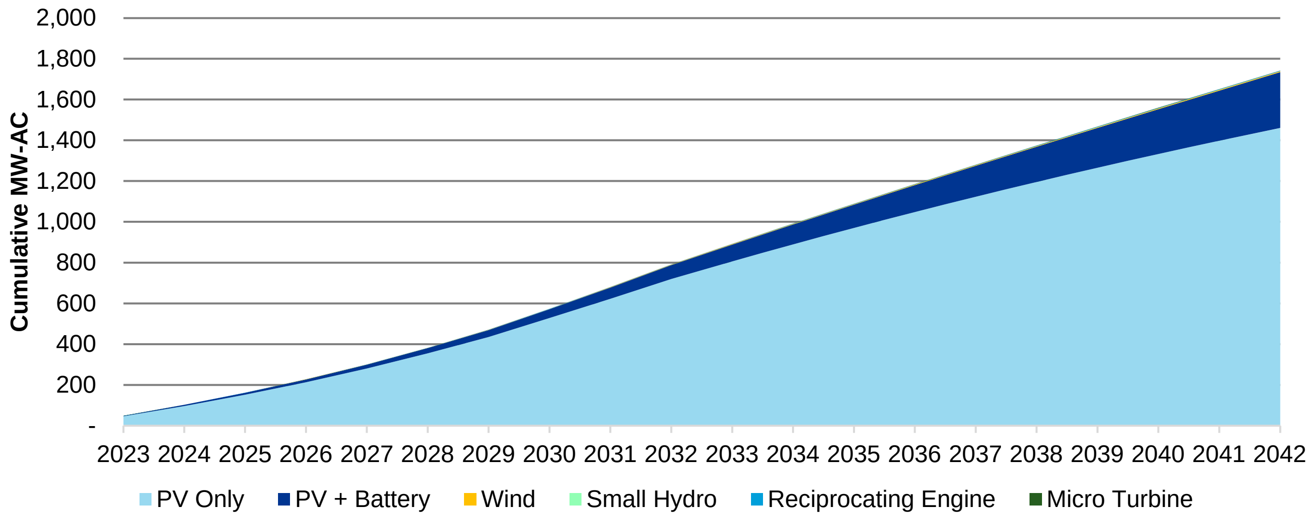


Figure 4-24 Cumulative New Capacity Installed by Technology (MW-AC), Utah High Case, 2023-2042

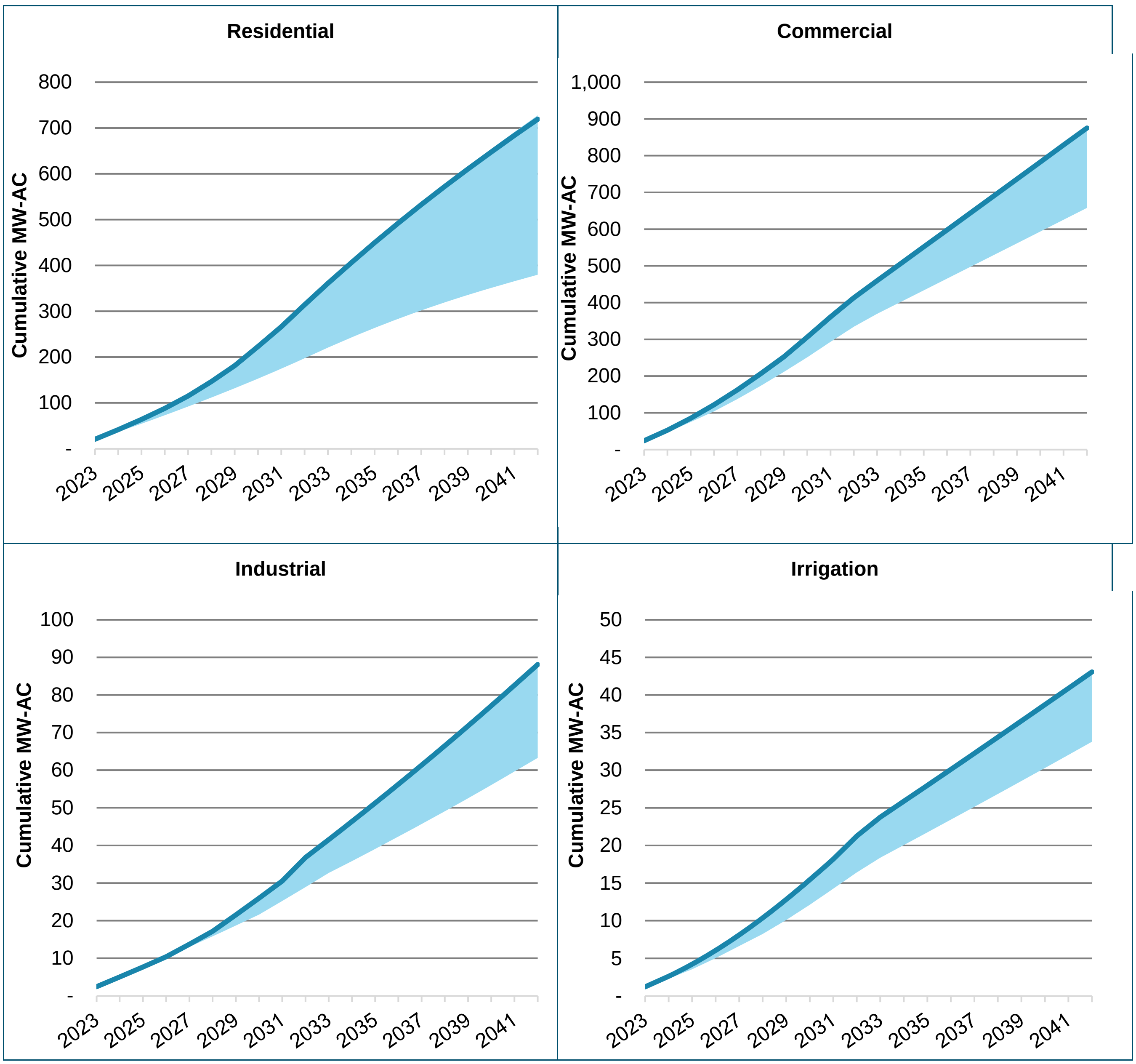


4.1.4.1 Utah PV Adoption by Sector

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 in in a PV + Battery configuration.

Figure 4-25 Cumulative New PV Capacity Installed by Sector Across All Scenarios, Utah, 2023-2042

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 140 MW of new private generation capacity over the next two decades in the base case. The 20-year low projection is about 47% less than the base case, or 74 MW. The high case is nearly the same as the base case, seen in Figure 4-26.

Washington state currently offers no incentives for private generation technologies. The residential sector has the largest share of the private generation capacity, ranging from 68% in the base and high cases to 55% in the low case. The next largest share of the capacity is forecasted in the commercial sector, ranging from 41% in the low case to 29% in the base and high cases. Washington'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 4-26 Cumulative New Private Generation Capacity Installed by Scenario (MW-AC), Washington, 2023-2042

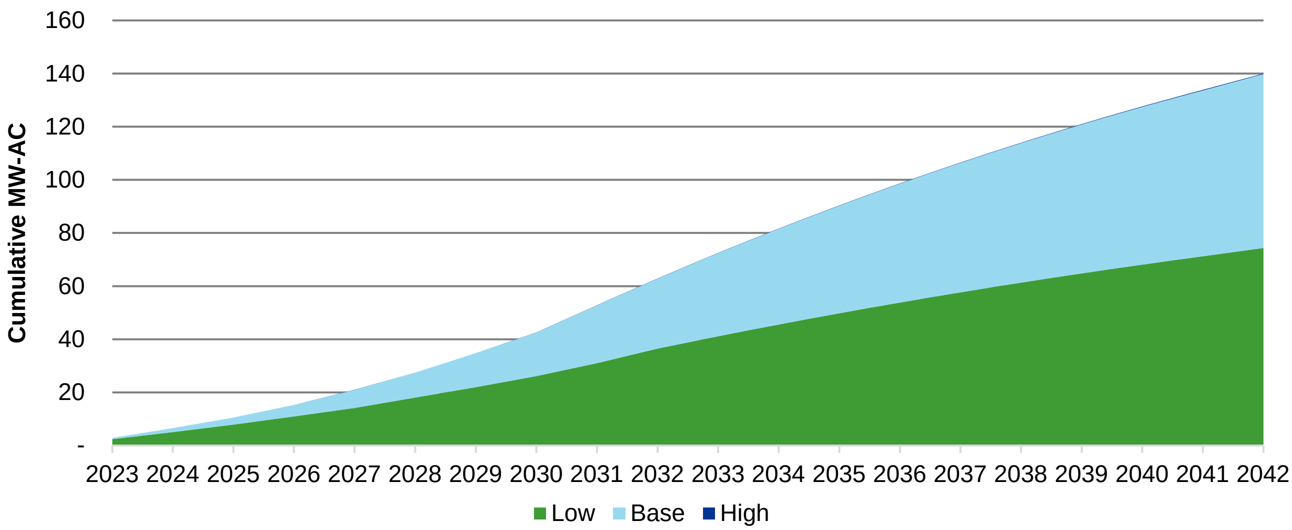


Figure 4-27 Cumulative New Capacity Installed by Technology (MW-AC), Washington Base Case, 2023-2042

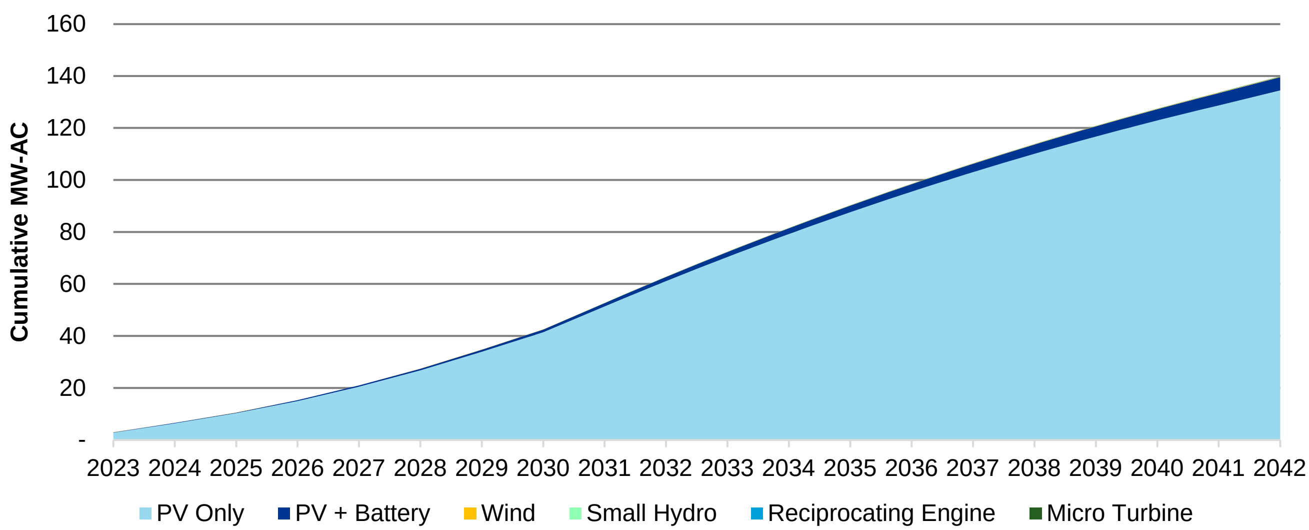


Figure 4-28 Cumulative New Capacity Installed by Technology (MW-AC), Washington Low Case, 2023-2042

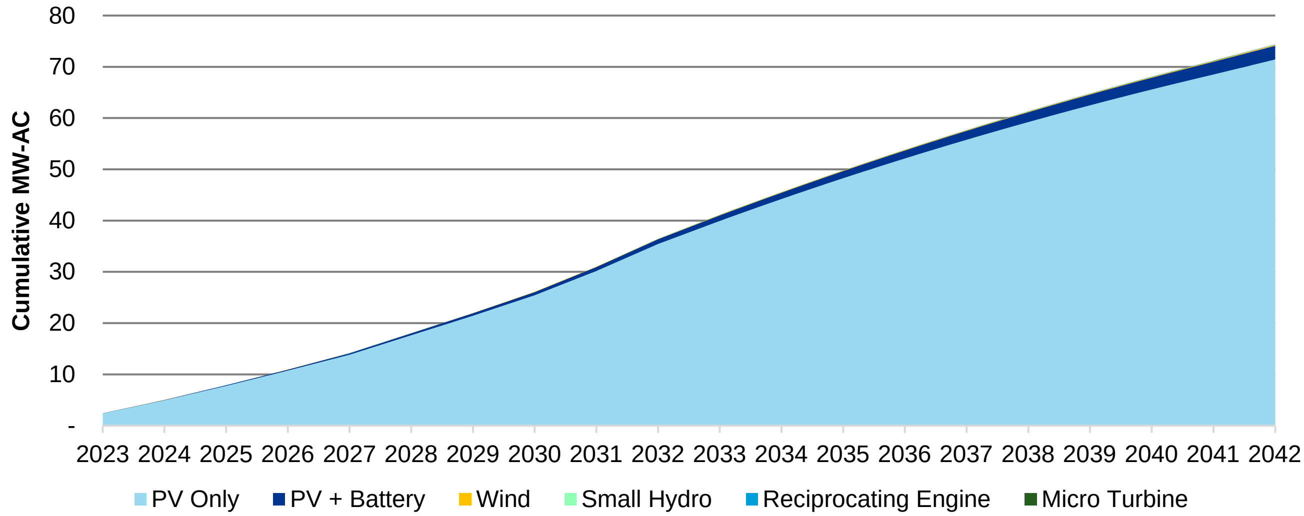
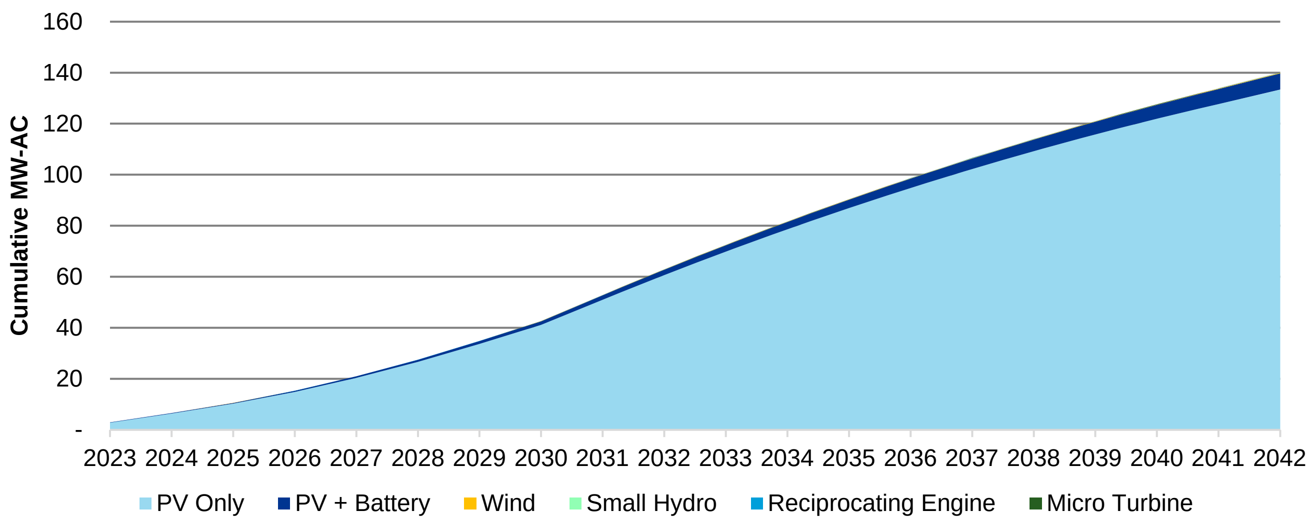


Figure 4-29 Cumulative New Capacity Installed by Technology (MW-AC), Washington High Case, 2023-2042

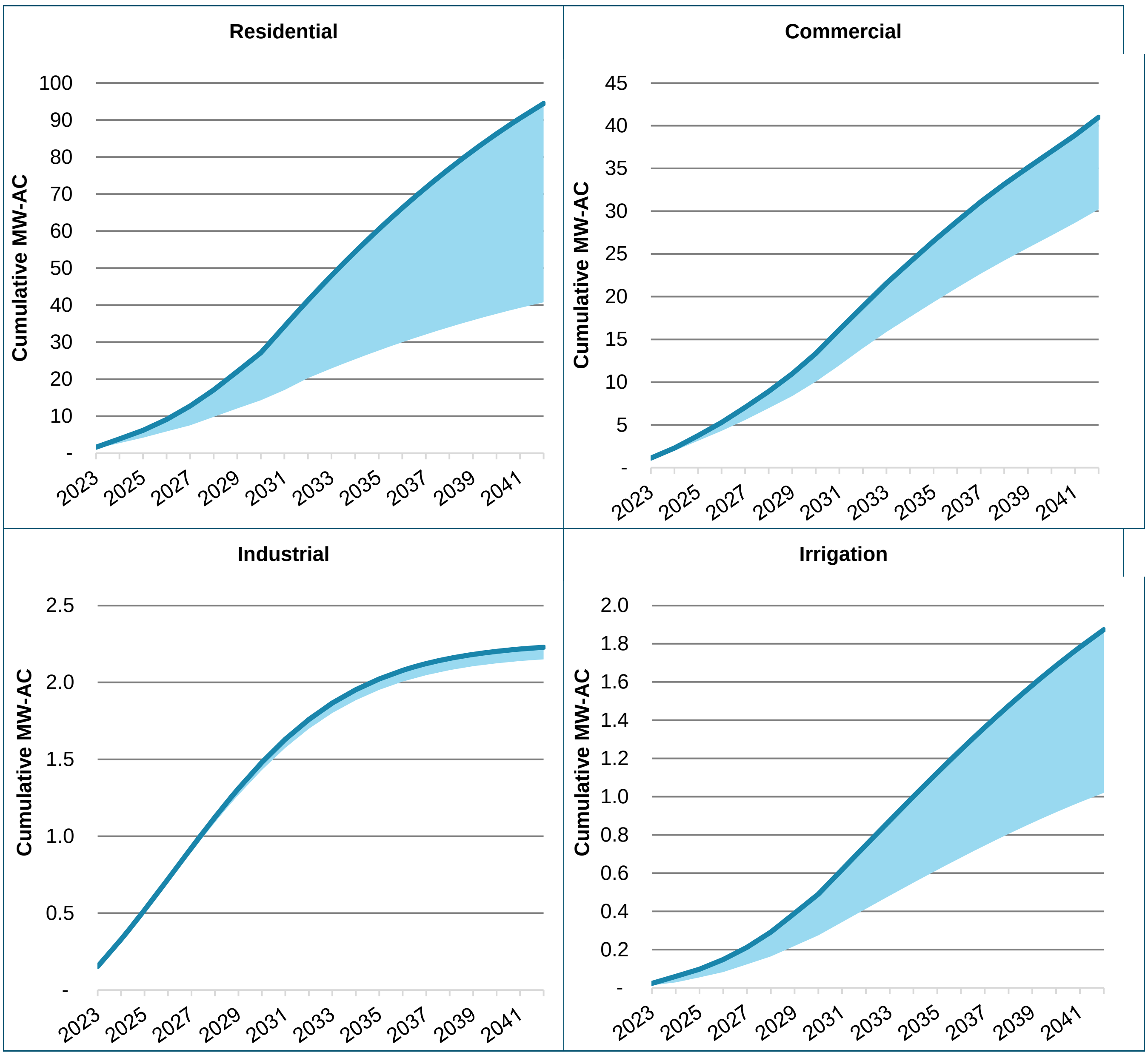


4.1.5.1 Washington PV Adoption by Sector

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 4-30 Cumulative New PV Capacity Installed by Sector Across All Scenarios, Washington, 2023-2042

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 51 MW of new private generation capacity over the next two decades in the base case. The 20-year high projection is approximately 2% greater than the base case and the low projection is about 50% less than the base case, or 52 MW and 26 MW, respectively.

Wyoming currently offers no incentives for private generation technologies. The residential sector has the largest share of the private generation capacity, ranging from 64% in the low case to 71% in the high and bae cases. The next largest share of the capacity is forecasted in the commercial sector, ranging from 28% in the high and base cases to 34% 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 4-31 Cumulative New Private Generation Capacity Installed by Scenario (MW-AC), Wyoming, 2023-2042

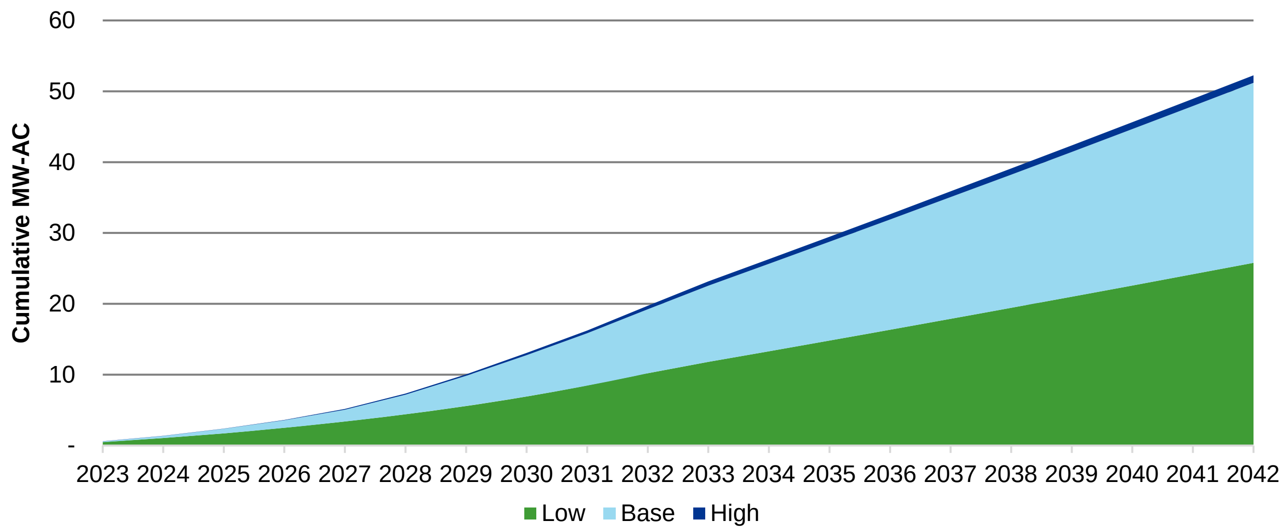


Figure 4-32 Cumulative New Capacity Installed by Technology (MW-AC), Wyoming Base Case, 2023-2042

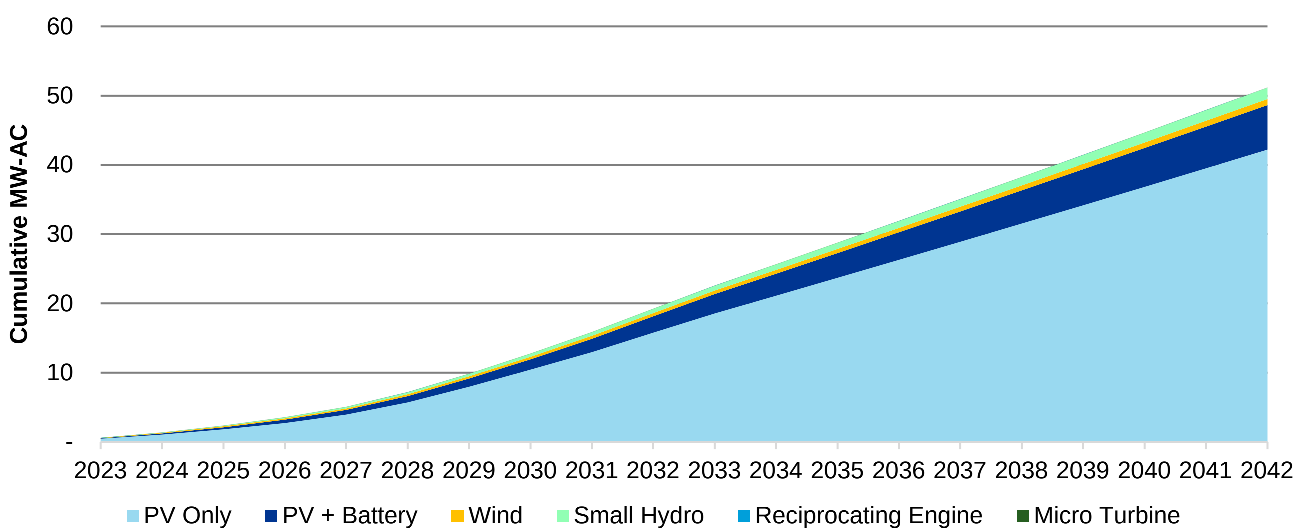


Figure 4-33 Cumulative New Capacity Installed by Technology (MW-AC), Wyoming Low Case, 2023-2042

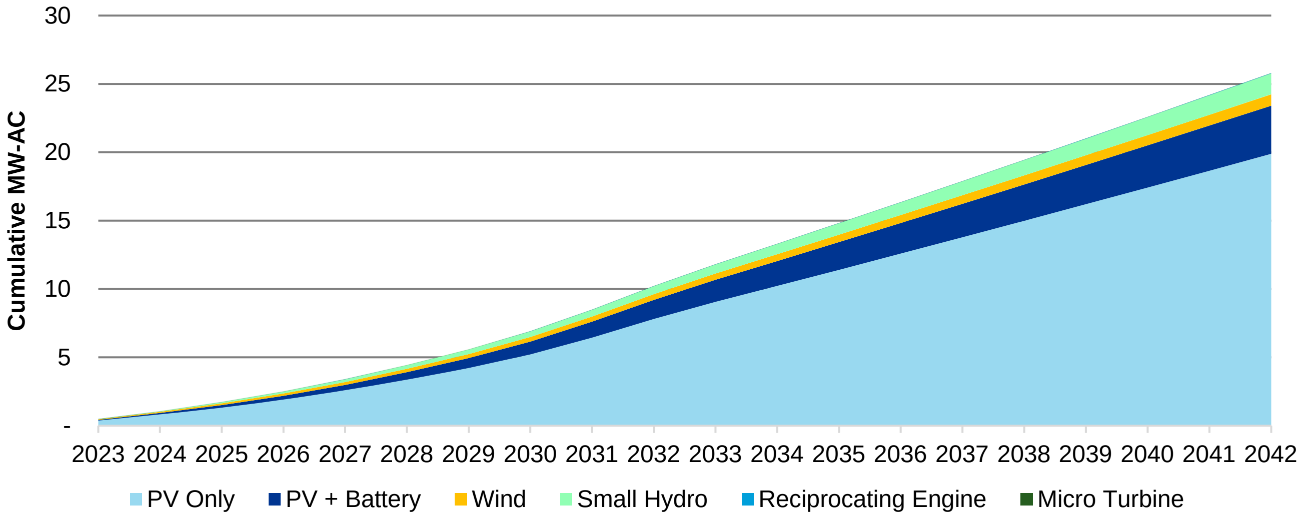
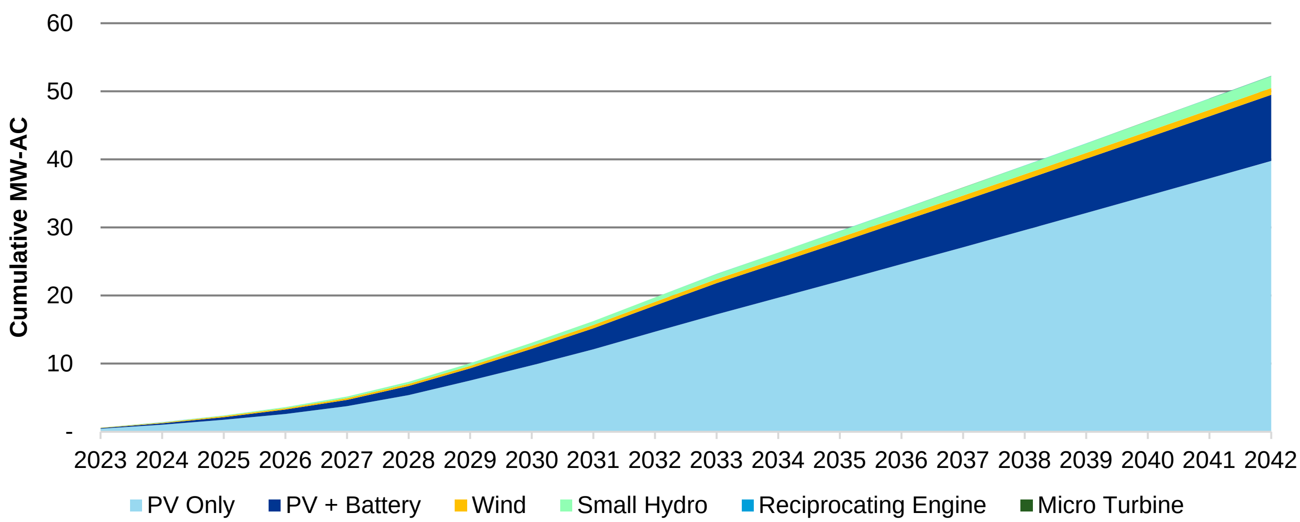


Figure 4-34 Cumulative New Capacity Installed by Technology (MW-AC), Wyoming High Case, 2023-2042

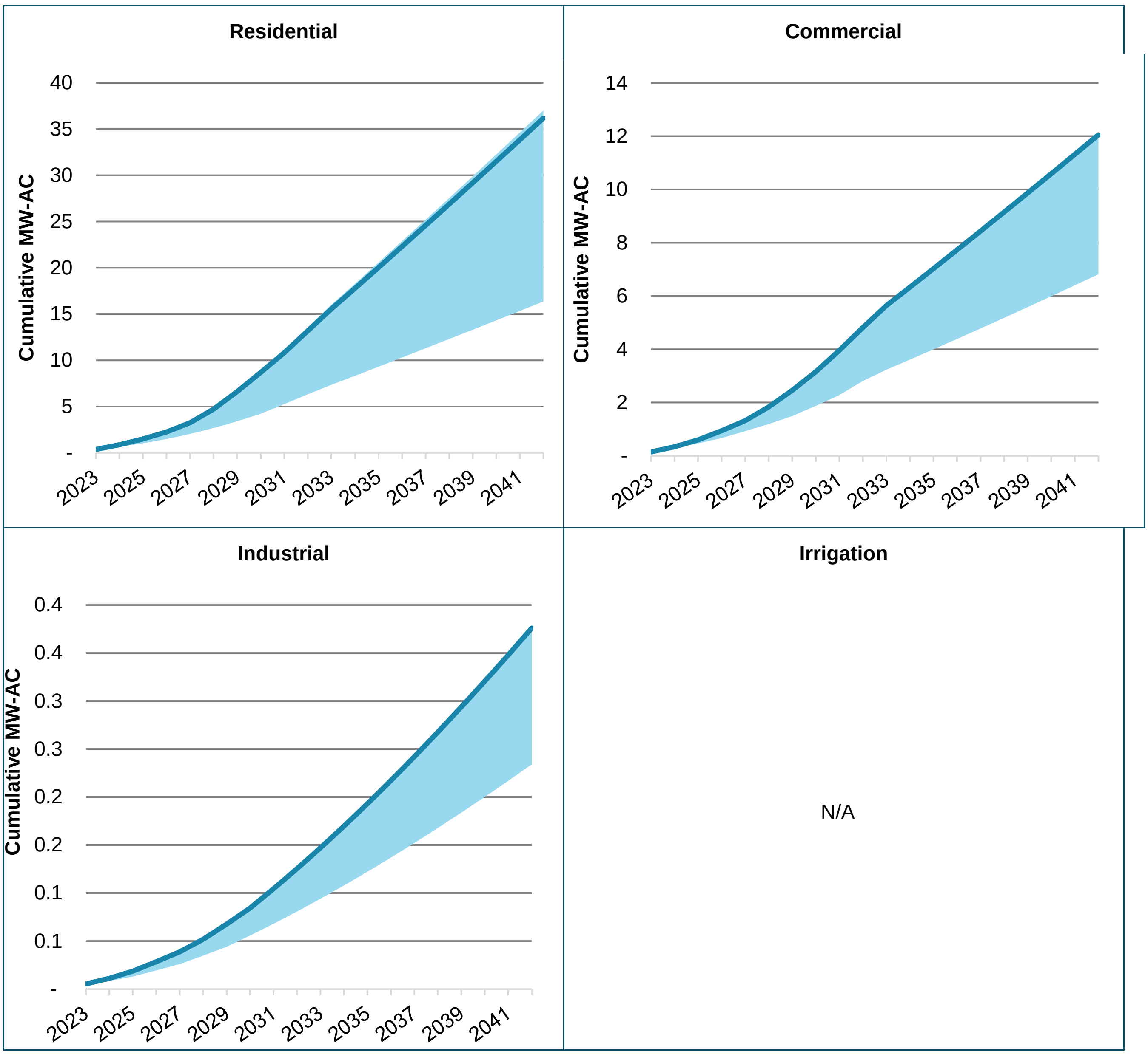


4.1.6.1 Wyoming PV Adoption by Sector

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 4-35 Cumulative New PV Capacity Installed by Sector Across All Scenarios, Wyoming, 2023-2042

Upper and lower bounds (in blue) represent the high and low case forecasts, with a line for the base case.



APPENDIX A TECHNOLOGY ASSUMPTIONS AND INPUTS

Appendix A.xlsx

APPENDIX B DETAILED RESULTS

Appendix B.xlsx

APPENDIX C WASHINGTON COGENERATION LEVELIZED COSTS

Section 480.109.100 of the Washington Administrative Code establishes high-efficiency cogeneration as a form of conservation that electric utilities must assess when identifying cost-effective, reliable, and feasible conservation for the purpose of establishing 10-year forecasts and biennial targets. This appendix provides the levelized cost of energy (LCOE) for the two CHP technologies analyzed in this report for three 10-year periods. LCOE is defined as the present cost of electricity generation for the specified technology over its useful lifetime.

Assumptions for the LCOE analysis of both reciprocating engines and microturbines in Washington state are provided in Table C-1and Table C-2 below, with additional information on the specific source for each metric. Similar to previous studies, the cost of system heat recovery was removed from the total system cost component, resulting in LCOE based only on electric power generation for each system. Where applicable, assumptions are presented nominally ($USD).

Table C-1 Reciprocating Engine LCOE Assumptions

METRIC	EXPECTED USEFUL LIFE (EUL)	INSTALLED COST *(INCLUDES INCENTIVES)*	VARIABLE O&M COST	FUEL COST	WACC
UNITS	Years	$/kW	$/MWh	$/MMBtu	%
2022	20	$2,565	$23	$5.67	6.88%
2030	20	$2,655	$27	$4.34	6.88%
2040	20	$2,721	$32	$6.61	6.88%
SOURCE	EPA Catalog of CHP Technologies (Sep. 2017)	DOE CHP Technology Fact Sheets (Reciprocating Engines)	DOE CHP Technology Fact Sheets (Reciprocating Engines)	PacifiCorp Natural Gas Forecast for Washington State	PacifiCorp IRP Assumption

Table C-2 Microturbine Engine LCOE Assumptions

METRIC	EXPECTED USEFUL LIFE (EUL)	INSTALLED COST *(INCLUDES INCENTIVES)*	VARIABLE O&M COST	FUEL COST	WACC
UNITS	Years	$/kW	$/MWh	$/MMBtu	%
2022	25	$3,135	$23	$5.67	6.88%
2030	25	$3,229	$27	$4.34	6.88%
2040	25	$3,294	$32	$6.61	6.88%
SOURCE	EPA Catalog of CHP Technologies (Sep. 2017)	DOE CHP Technology Fact Sheets (Reciprocating Engines)	DOE CHP Technology Fact Sheets (Reciprocating Engines)	PacifiCorp Natural Gas Forecast for Washington State	PacifiCorp IRP Assumption

The results of the CHP LCOE analysis are shown below. The calculated levelized costs for both technologies are similar in each analysis year.

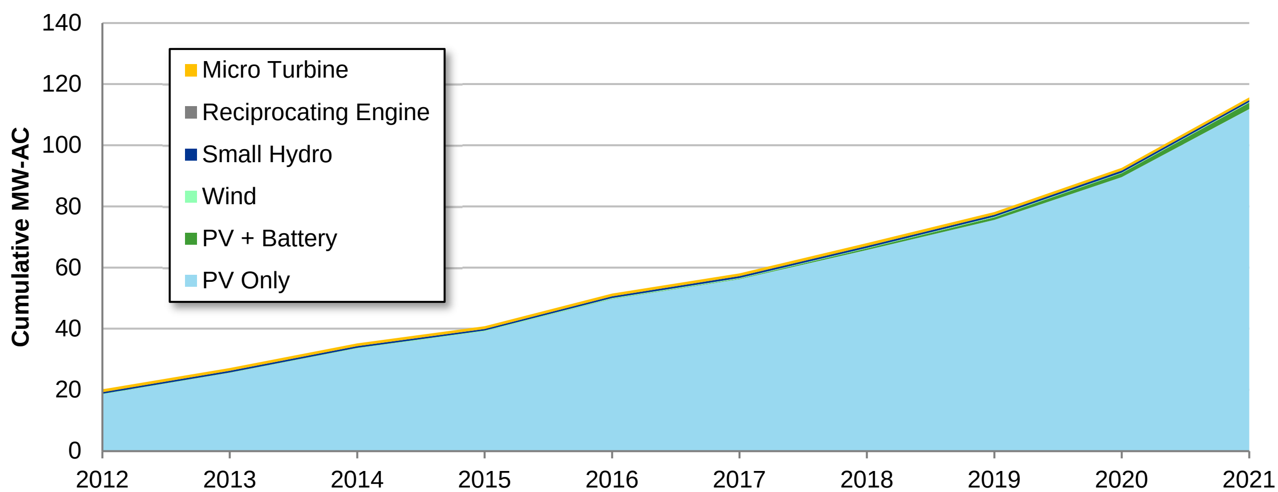
Table C-3 LCOE Results for CHP Systems in Washington State

TECH	RECIPROCATING ENGINES	MICROTURBINES
UNITS	$/MWh	$/MWh
2022	$89.3	$92.8
2030	$99.4	$99.9
2040	$121.4	$116.3

APPENDIX D OREGON DISTRIBUTION SYSTEM PLAN RESULTS

DNV prepared the Long-Term Private Generation (PG) Resource Assessment for PacifiCorp's Oregon distributed energy resource (DER) adoption forecast at the circuit level to support PacifiCorp's 2023 Oregon Distribution System Plan (DSP). This study evaluated the expected adoption of behind-the-meter DERs including photovoltaic solar (PV only), photovoltaic solar coupled with battery storage (PV + Battery), wind, small hydro, reciprocating engines and microturbines for a 20-year forecast horizon (2023-2042). The adoption model DNV developed for this study is calibrated to the current[20] market penetration of these technologies, shown in Figure D-1**.**

Figure D-1 Historic Cumulative Installed PG Capacity by Technology, PacifiCorp, Oregon, 2012-2021



To date, about 99 percent of existing private generation capacity installed in PacifiCorp's Oregon service territory is PV or PV + Battery. To inform the adoption forecast process, the Company 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 private generation market in Oregon in the future years of this study.

For each technology and sector, PacifiCorp developed three scenarios: 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 costs and retail rates; the high and low cases are used as sensitivities to test how changes in technology costs and retail rates impact customer adoption of these technologies. These scenarios use technology cost and performance assumptions specific to PacifiCorp's Oregon service territory in the base year of the study. The base case assumes the current federal income tax credit schedules and state incentives, retail electricity rate escalation from the AEO[21] reference case, and a blended version of the NREL Annual Technology Baseline[22] moderate and conservative technology cost forecasts. In the high case, retail rates increase more rapidly, and technology costs decline at a faster rate compared to the base case to incentivize greater adoption of PG. For the low case, retail rates increase at a slower rate than the base case and technology costs decrease at a slower rate.

[20] PacifiCorp private generation interconnection data as of February 2022.

[21] U.S. Energy Information Administration, Annual Energy Outlook 2022 (AEO2022), (Washington, DC, March 2022).

[22] NREL (National Renewable Energy Laboratory). 2021. 2021 Annual Technology Baseline. Golden, CO: National Renewable Energy Laboratory.

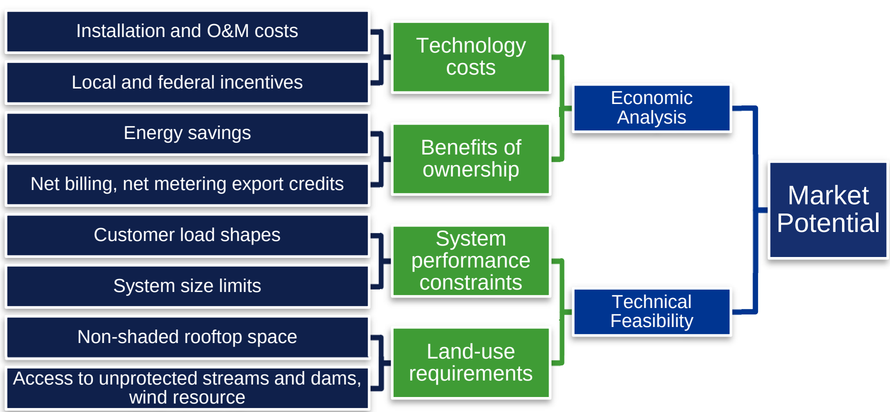
D.1 Study Methodologies and Approaches

The forecasting methodologies and techniques applied by PacifiCorp in this analysis are commonly used in small-scale, behind-the-meter energy resource and energy efficiency forecasting. To forecast private generation adoption at the circuit-level, the Company first developed an adoption model to estimate total PG potential for PacifiCorp's Oregon service territory and then disaggregated these results to develop PG potential estimates for each circuit. The methods used to develop the territory and circuit level results are described in more detail below.

D.1.1 State-Level Forecast Approach

DNV developed a behind-the-meter net economic perspective that includes the acquisition and installation costs for each technology and incorporates the available incentives and economic benefits of ownership as offsets which assumed that the current net metering policies for Oregon remained in place throughout the study horizon. The economic analysis calculated payback by year for each technology by sector. A corresponding technical feasibility analysis determined the maximum, feasible, adoption for each technology by sector. The results of the technical and economic analyses were then used to inform the market adoption analysis. The methodology and major inputs to the analysis are shown in Figure D-2. Changes to technology costs, retail rates, and federal tax credits used in the high and low cases impact the economic portion of the analysis.

Figure D-2 Methodology to Determine Market Potential of Private Generation Adoption



PacifiCorp 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, adoption increasing as the technology becomes more mainstream, and eventually a tapering off among 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 vary by year in the study.

The model is characterized by three parameters—an innovation coefficient, an imitation coefficient, and the ultimate market potential. The last of these we set equal to the payback-based maximum level of adoption. Together, these three parameters also determine the time to reach maximum adoption and 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 the Company's Oregon service territory.

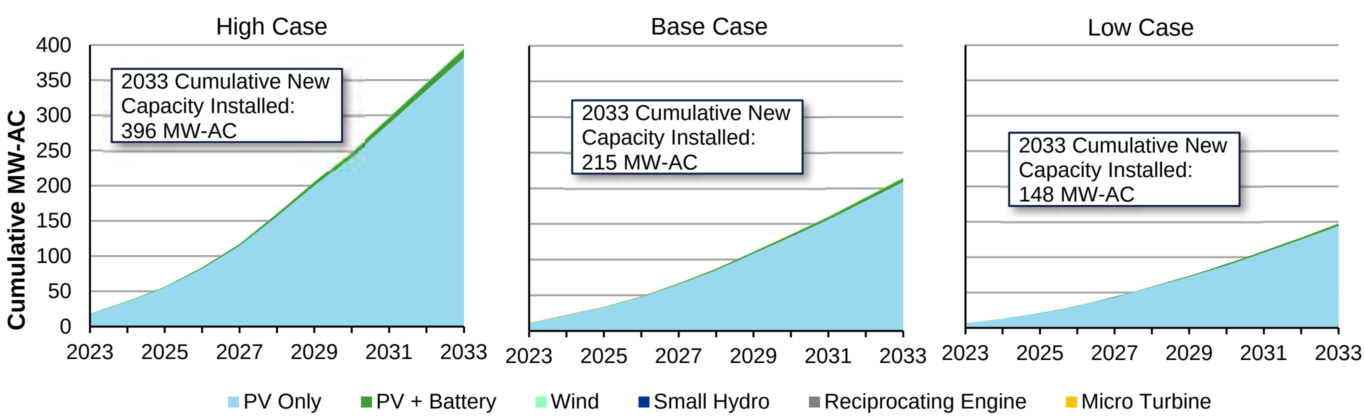
D.1.2 Circuit-Level Forecasting Approach

PacifiCorp conducted a bottom-up approach to develop circuit-level adoption models for each sector and technology. The approach chosen for developing circuit-level forecasts was to disaggregate the state-level forecast described in the previous section. This was due to the use of adoption drivers from data at varying levels of geographic granularity. The circuit-level adoption models incorporated county-level private generation installation data and resource availability by technology[23], census-tract-level demographic data[24] and circuit-level reliability data. The Company used circuit-level customer counts by sector to further segment the localized adoption models by sector and technology. The Company ultimately used a bottom-up approach to develop circuit-level adoption models for each circuit, but due to the above data gaps, their purpose was only to develop factors to allocate the state-wide analysis to each circuit.

D.2 Private Generation Forecast Results

Figure D-3 compares the new service territory-level private generation capacity, in cumulative MW-AC by 2033, projected for each scenario evaluated. The capacity forecasted is incremental to what is already installed in PacifiCorp's Oregon service territory, shown in Figure D-1.

Figure D-3 Private Generation Forecast by Technology, PacifiCorp Oregon, All Cases



Similar to the trends observed in current installed capacity, solar PV[25] makes up 99% of the new PG capacity forecast throughout the study period in all cases. By 2033, the cumulative new PV Only capacity in the base case is 209 MW and PV + Battery capacity is 5 MW. Compared to the base case, the low case forecasts 31% less PV Only capacity, and about 40% percent less PV + Battery capacity. The PV Only cumulative new capacity in the high case in 2033 is 83% greater than the base case. In the high case, 2033 PV + Battery cumulative new capacity is forecasted to be more than double the base case, at 11 MW.

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[23] Conditions suitable for wind and hydro vary widely by region, and the economics of solar adoption is affected by local weather patterns.

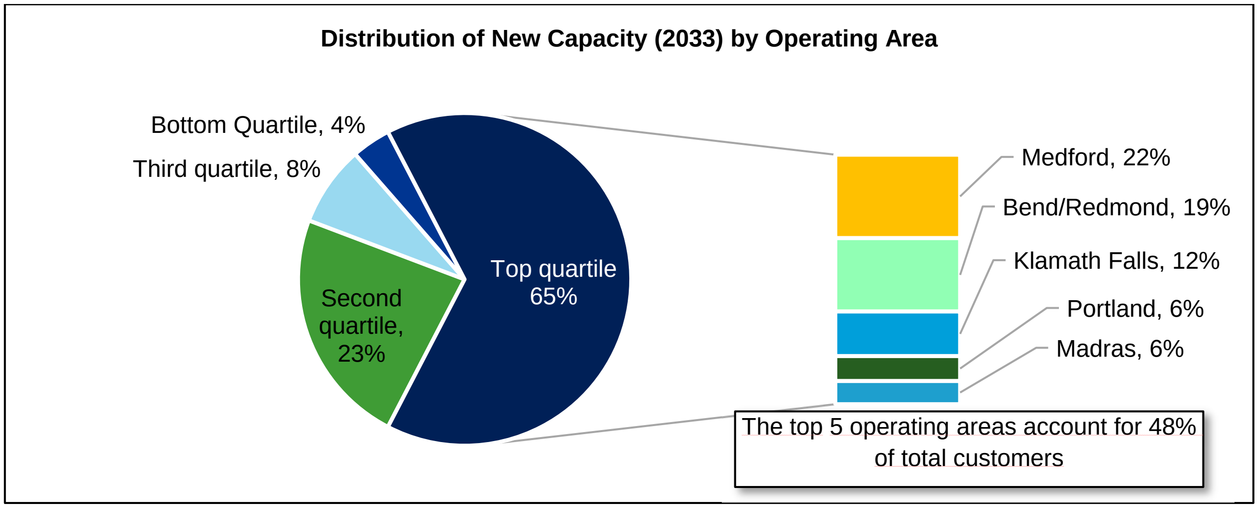
[24] Data including household income, education-level, and home ownership.

[25] The term solar PV, here, is inclusive of PV Only and PV + Battery systems.

D.2.1 Circuit-Level and Substation-Level Results Findings

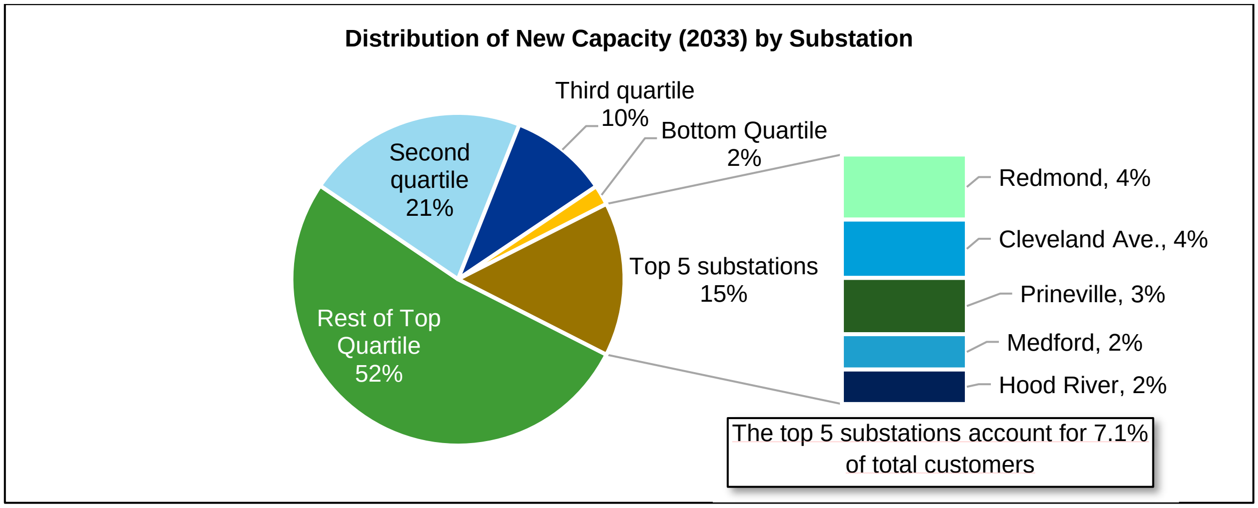
The charts in Figure D-4, Figure D-5, and Figure D-6 show the distribution of new capacity in 2033 by operating area, substation, and circuit within the base case private generation forecast.

Figure D-4 Private Generation Forecast Disaggregation by Operating Area, PacifiCorp Oregon, Base Case



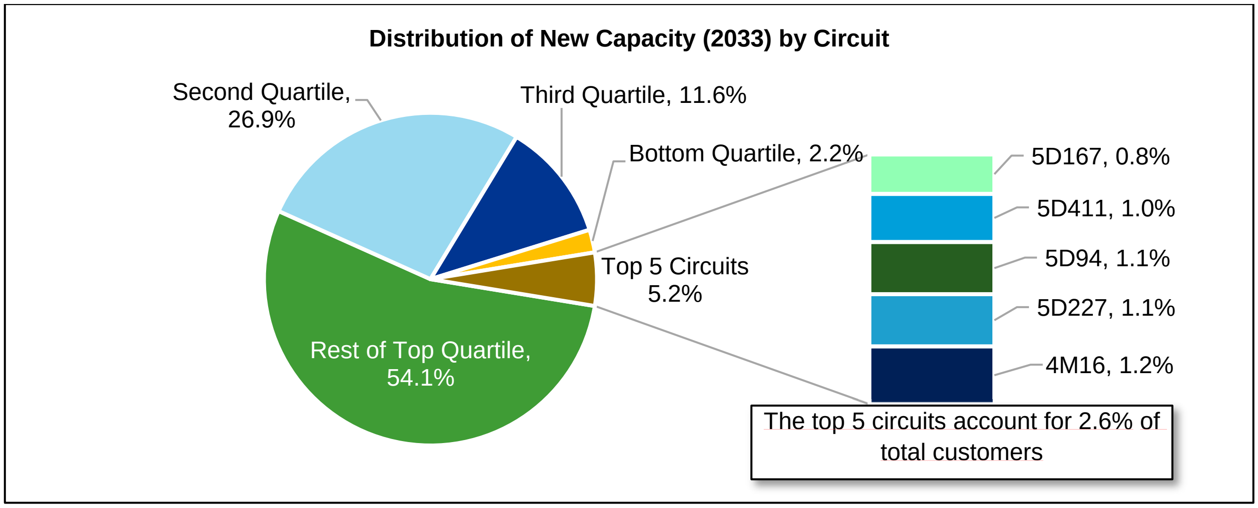
The top five (ranked by new capacity) of PacifiCorp's 22 Oregon operating areas account for 65% of the total forecast capacity in 2033 while only accounting for 48% of total customers.

Figure D-5 Private Generation Forecast Disaggregation by Substation, PacifiCorp Oregon, Base Case



The top five of PacifiCorp's 193 substations account for 15% of 2033 forecast capacity (compared to 7% of customers), with the entire top quartile (representing 49% of customers) accounting for 67%.

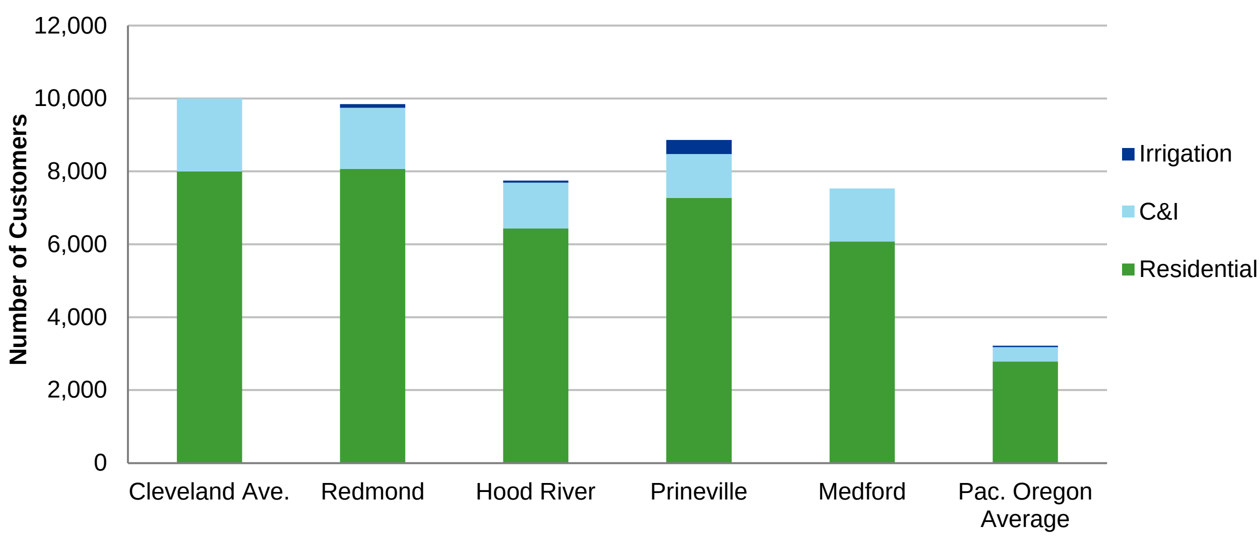
Figure D-6 Private Generation Forecast Disaggregation by Circuit, PacifiCorp Oregon, Base Case



Of the 504 circuits analyzed, the top five (representing 2.6% of customers) account for 5.2% of total forecast capacity, with the top quartile (representing 36% of customers) accounts for 59%.

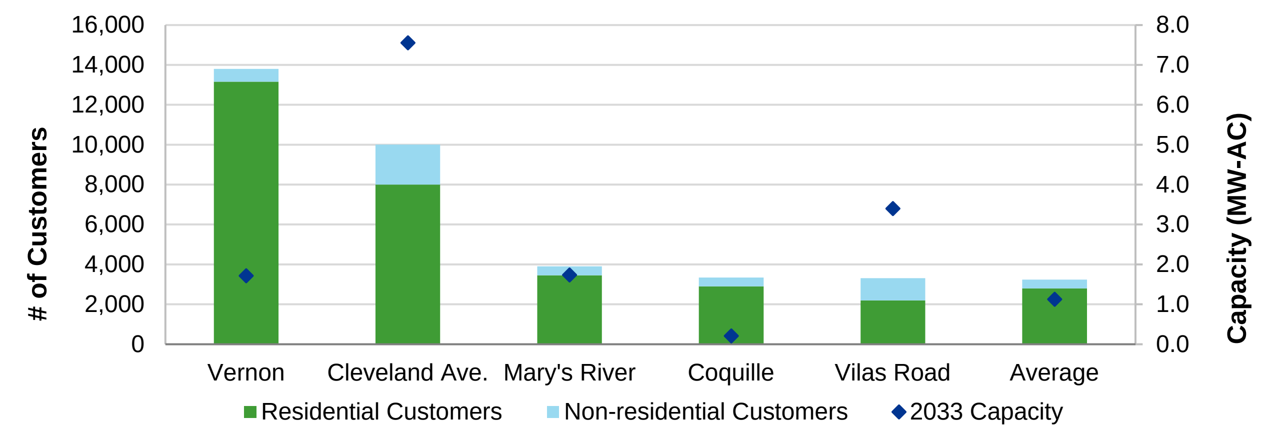
Figure D-7 shows the breakdown of customers, by sector, at the top five substations. Because capacity sizes are larger for irrigation, commercial and industrial customers than for residential (four times larger for irrigation, nine times for commercial and 17 times for industrial), C&I customers contribute to capacity totals disproportionately to their share of the customer population. New construction has a two-fold impact on the capacity forecast: Directly, since there are customers on the substation who could adopt private generation, and indirectly, since new construction has a higher propensity to adopt solar (with and without storage) than existing buildings. All substations except Hood River are in areas where population growth is higher than the statewide average.

Figure D-7 Customer Mix of Top Five Substations Compared to the Average of All Substations



With 193 substations across the state and so many factors influencing the disaggregated forecast, it is not feasible to conduct a deep dive of each substation's capacity forecast. Instead, we selected five substations to illustrate how different underlying factors affected their capacity allocations (see Figure D-8). These substations were chosen to illustrate a range of characteristics influencing adoption, not because they are of special interest for planning.

Figure D-8 Customer Attributes of Selected Substations Compared to Average PacifiCorp Oregon Substation



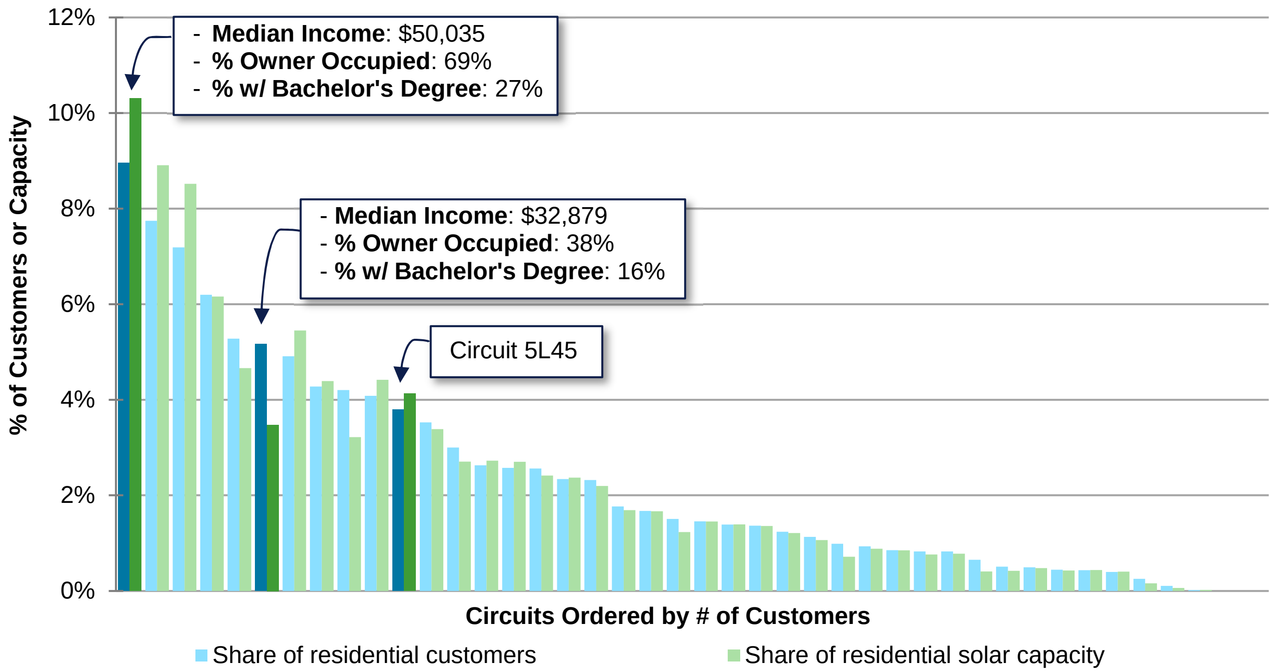
Substation Attribute	Vernon	Cleveland Ave.	Mary's River	Coquille	Vilas Road	Average
Operating Area	Portland	Bed/ Redmond	Corvallis	Coos Bay/Coquille	Medford	--
Climate (for Solar)	Less favorable	More favorable	Less favorable	Less favorable	More favorable	--
Population Growth	1.0%	2.0%	1.3%	0.0%	1.7%	1.0%
% Non-res. Customers	5%	20%	12%	13%	34%	16%
Current Res. Solar Penetration	1.4%	3.0%	3.1%	0.9%	2.4%	1.8%
Home Ownership Rate	70%	55%	61%	77%	75%	65%
Avg. Household Income	$108,604	$136,460	$102,301	$74,543	$58,752	$87,499

Vernon and Cleveland Avenue are among PacifiCorp's top substations by number of customers but have very different climates and customer mixes. Cleveland Avenue lies on the east side of the Cascades and receives more sunshine, while Vernon is in the Portland operating area, which has more rain and more cloudy days which impacts solar generation and thus adoption. Nonresidential PV systems are larger than residential systems (modeled commercial systems are 9 times larger; industrial systems are 17 times larger), so Cleveland Ave's higher share of nonresidential customers (20%) increases its capacity forecast compared to Vernon, with only 5% nonresidential customers. Cleveland Avenue also has double the rate of expected population growth that Vernon does over the next decade.

The remaining three substations shown each have a total customer count close to the state-wide average, but very different capacity forecasts. Mary's River has high historic adoption and higher-than-average population growth, but less non-residential and a lower home ownership rate than average resulted in a share of capacity almost proportional to the number of customers. Coquille has very low historic adoption, perhaps due to its less favorable climate for solar generation, and no expected population growth. Those factors, paired with lower-than-average income and low share of non-residential customers led to a very low level of forecast private generation capacity. The last substation we wish to highlight is Vilas Road in the Medford operating Area. This substation has a very high share of non-residential customers at 34%, and the higher capacity systems for these customers drives up the forecast. A favorable climate for solar with high historic adoption (residential and commercial) led to this substation being allocated a higher-than-proportional share of capacity.

Figure D-9 zooms in on the Klamath Falls operating area to compare how the allocation of PV only capacity compares to the distribution of customers by circuit. For each circuit in the Klamath Falls operating area, the chart shows the share of residential customers to the corresponding share of the 2033 residential PV Only capacity forecast. The figure demonstrates visually that more favorable factors for adoption, such as higher rates of home ownership, higher income, higher education, etc. result in a higher than proportional allocation of capacity.

Figure D-9 Share of Residential Customers vs. Share of Residential PV Only Capacity in 2033, Klamath Falls Operating Area



D.3 Conclusions

As part of the DSP, PacifiCorp evaluated each of the previously discussed private generation scenarios. However, as the baseline DSP private generation forecast, PacifiCorp considers the base case forecast to be most appropriate for planning, given current technology costs, incentive levels and net metering policies in place in Oregon.

Our analysis incorporated the current rate structures and tariffs offered to customers in Oregon. 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 — traditional net metering — does not incentivize PV + Battery storage co-adoption.

The sensitivity analysis found a greater difference between the base case and the upper bound of private generation adoption than the base case and lower bound of adoption. The low case assumed higher technology costs and lower retail electricity rates than the other cases, reducing the economic appeal of private generation despite incentives being unchanged. For the high case, an assumed extension to the residential federal investment tax credit provided a significant boost to adoption alongside the lower technology costs and higher retail electricity rates used in that analysis. The resulting new capacity in 2033 is about 31% less than the base case, while the high case is 84% greater than the base.

D.3.1 Future Work

Developing the circuit-level adoption models within the Oregon adoption model revealed additional areas of research related to private generation and behind-the-meter battery storage adoption that would enhance future work. The following is a list of potential future enhancements to this study:

1. A more nuanced approach to the new construction forecast would consider the creation of new circuits in high-growth areas. The current study allocates new construction only to existing circuits.
2. The distribution analysis requires integrating data at different geographical resolutions (state, county, census tract and circuit). While PacifiCorp's data mapped circuits geographically, there were challenges in matching customer billing data to circuits. This study also used existing customer counts by sector by circuit, but corresponding energy use could not be calculated at the circuit-level. Similarly, existing private generation could only be mapped at the county level since interconnection data had incomplete customer circuit information. Future studies will benefit from the circuit-level load forecasts PacifiCorp is developing for this DSP.
3. Storage dispatch modeling would benefit from a finer disaggregation of large commercial and industrial load shapes. Technology that is not broadly cost-effective could still be beneficial for customers with certain load profiles that were not visible using class-level load shapes.
4. Resilience appeared to be a significant driver of adoption. For PV + Battery storage, resilience could be a more significant driver of adoption than economics. A deeper understanding of what customer-types value resilience and how that affects their willingness to pay would help refine the forecast.

APPENDIX E BEHIND-THE-METER BATTERY STORAGE FORECAST

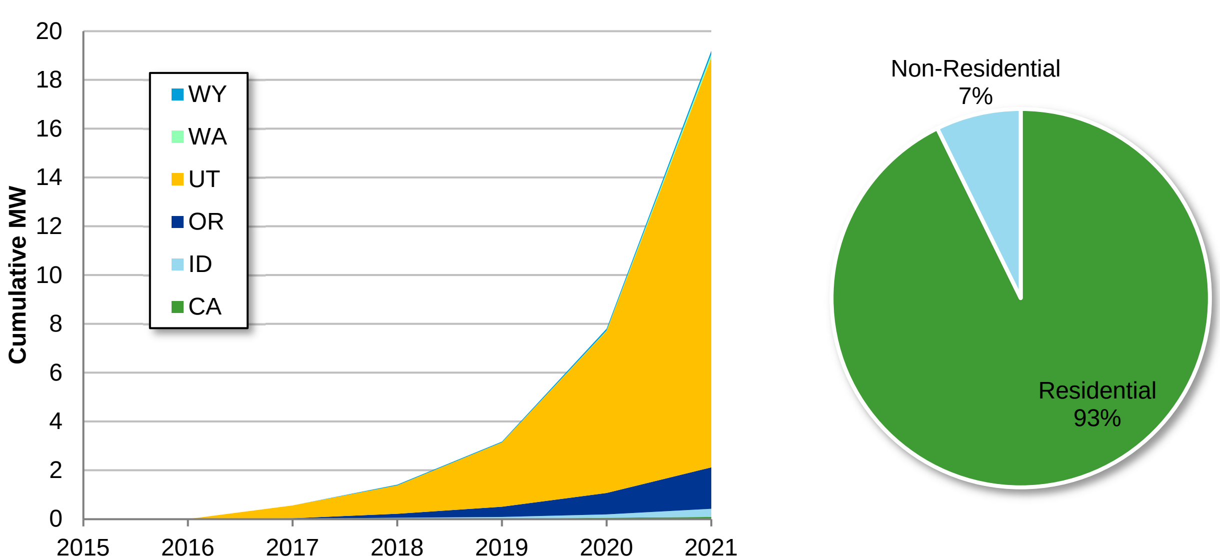
DNV prepared a behind-the-meter battery storage forecast as a part of the Long-Term Private Generation (PG) Resource Assessment for PacifiCorp covering their service territories in Utah, Oregon, Idaho, Wyoming, California, and Washington to support PacifiCorp's 2023 Integrated Resource Plan (IRP). This study evaluated the expected adoption of behind-the-meter battery storage systems coupled with PV systems over a 20-year forecast horizon (2023-2042) 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 3.2.5.

The adoption model DNV developed for this study is calibrated to the current[26] installed and interconnected behind-the-meter battery capacity that is paired with a PV system, shown in Figure E-1.

Figure E-1 Historic Cumulative Installed Behind-the-Meter Battery Storage Capacity, PacifiCorp, 2012-2021

Historic Cumulative Installed Battery Capacity by State

Historic Cumulative Installed Battery Capacity by Sector



E.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.

[26] PacifiCorp private generation interconnection data as of February 2022.

DNV used the same forecasting methodologies and approaches for the BTM battery storage forecast as the private generation forecast. The methods used to develop the results of the forecast are described in detail in section 3.4 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.

E.1.1 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 modelled 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. For non-residential customers, the dispatch model used energy arbitrage to reduce demand charges and time-of-use charges, where applicable.

E.2 Results

In the base case scenario, DNV estimates 227 MW of new battery storage capacity will be installed in PacifiCorp's service territory over the nest twenty years (2023-2042). Figure E-2 shows the relationship between the base case and low and high case scenario forecasts. The low case scenario estimates 151 MW of new capacity over the 20-year forecast period—compared to 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 264 MW of new private generation capacity installed by 2042. The twenty year total new capacity forecasted in the high case is about 16% greater than the base case, while the low case is 34% less.

Table E-1 Cumulative Adopted Battery Storage Capacity by 2042, by Scenario

SCENARIO	CUMULATIVE CAPACITY (2042 MW)
Base	227
Low	151
High	264

Figure E-2 Cumulative New Battery Storage Capacity Installed by Scenario (MW), 2023-2042

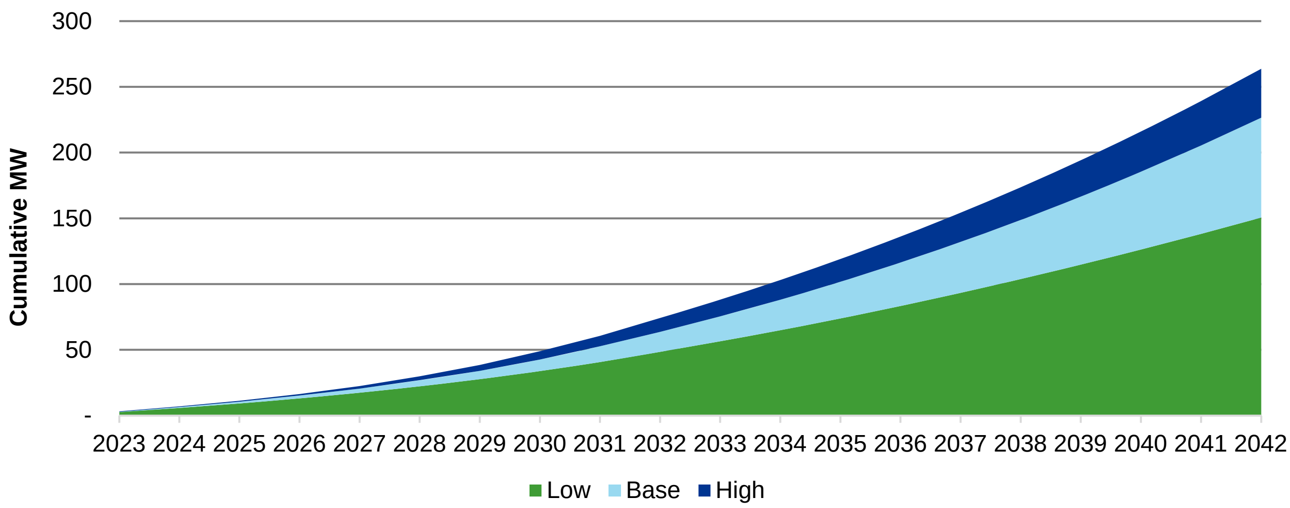


Figure E-3, Figure E-4, and Figure E-5 show the forecasts by customer sector and technology for each scenario. In all scenarios of the forecast, the residential sector represents about 90% of the new battery storage capacity forecasted to be installed over the next twenty years. The commercial, industrial, and irrigation sectors have been bundled into a single “Non-Residential” sector for the purpose of presenting 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 indicates 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.

Figure E-3 Cumulative New Battery Storage Capacity Installed by Technology (MW), 2023-2042, Base Case

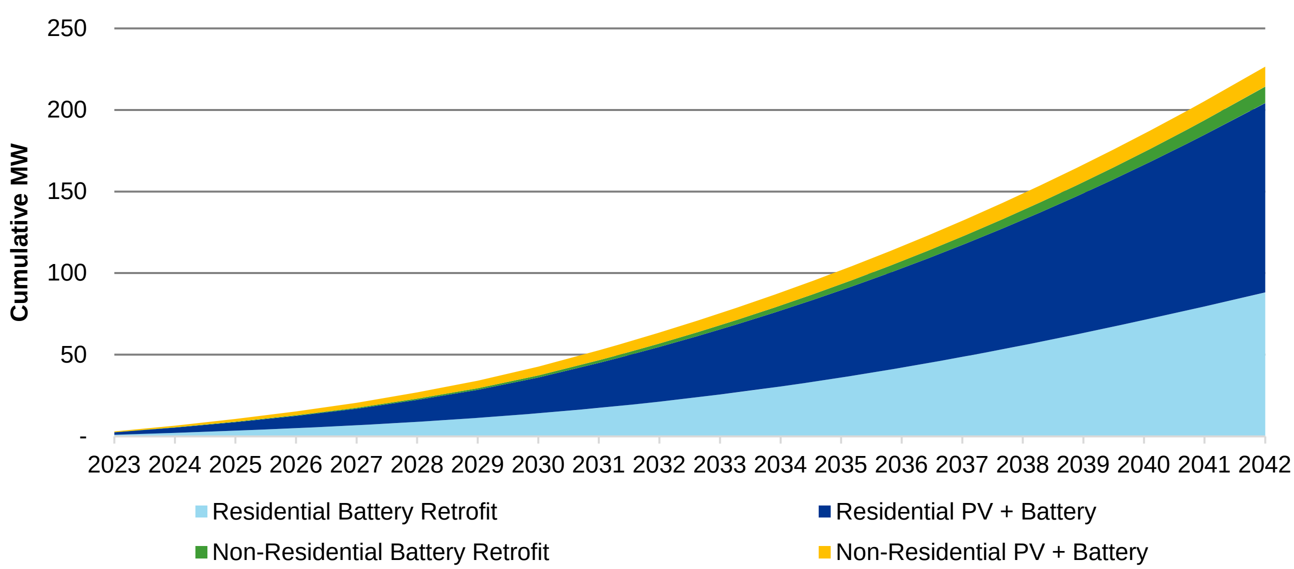


Figure E-4 Cumulative New Battery Storage Capacity Installed by Technology (MW), 2023-2042, Low Case

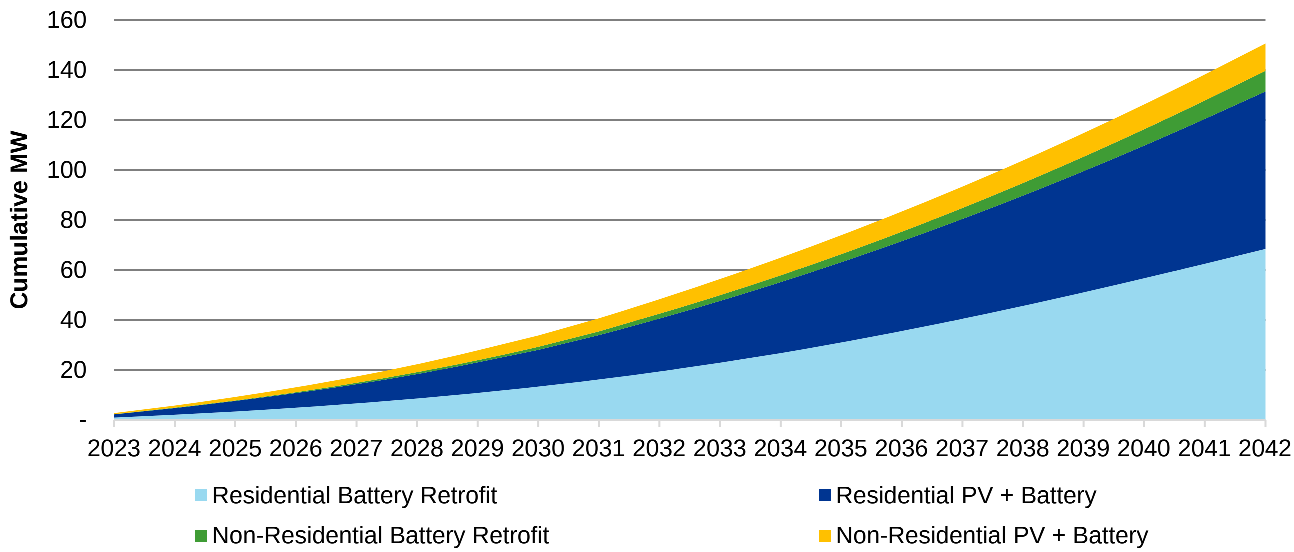
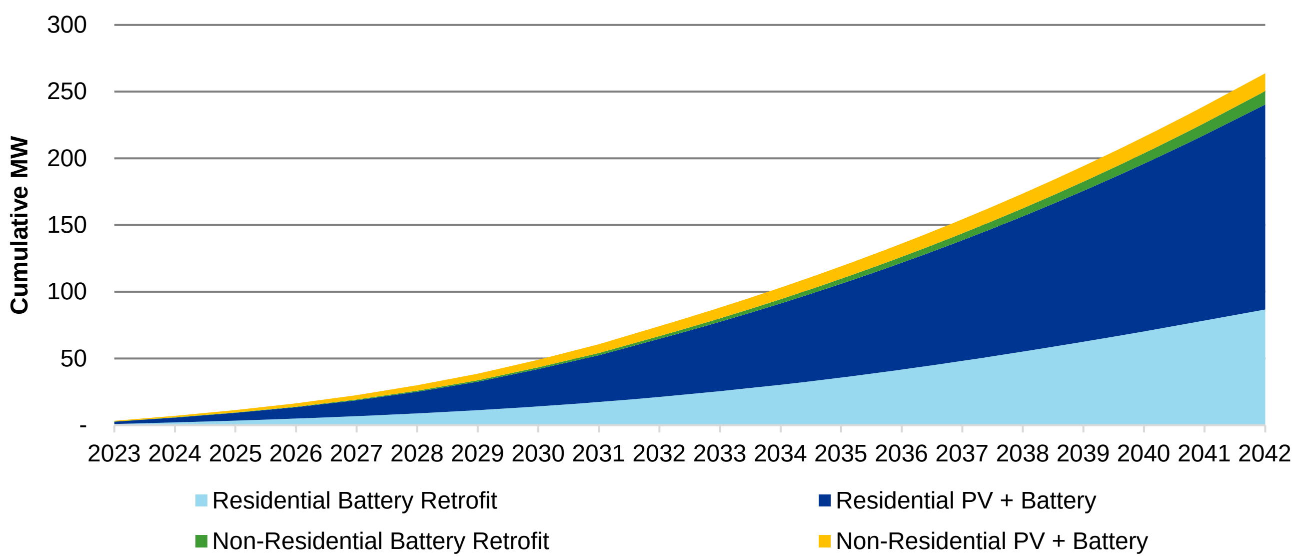


Figure E-5 Cumulative New Battery Storage Capacity Installed by Technology (MW), 2023-2042, High Case



E.3 Storage Capacity Results by State

As was the case in the private 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[27].

Figure E-6 Cumulative New Battery Storage Capacity Installed by State (MW), 2023-2042, Base Case

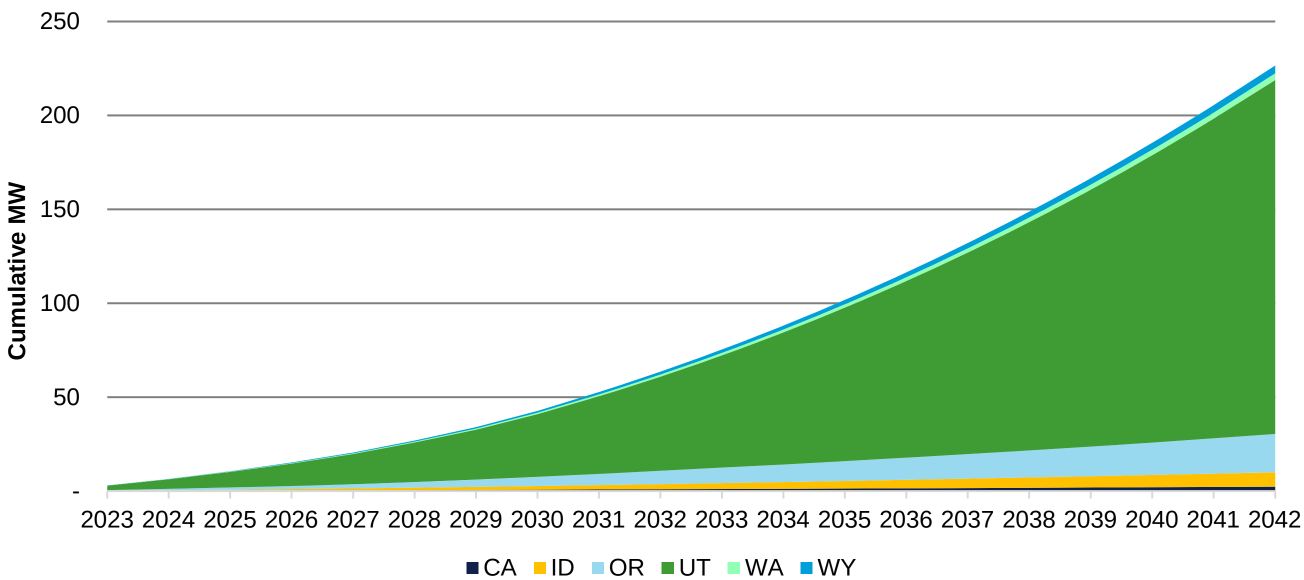
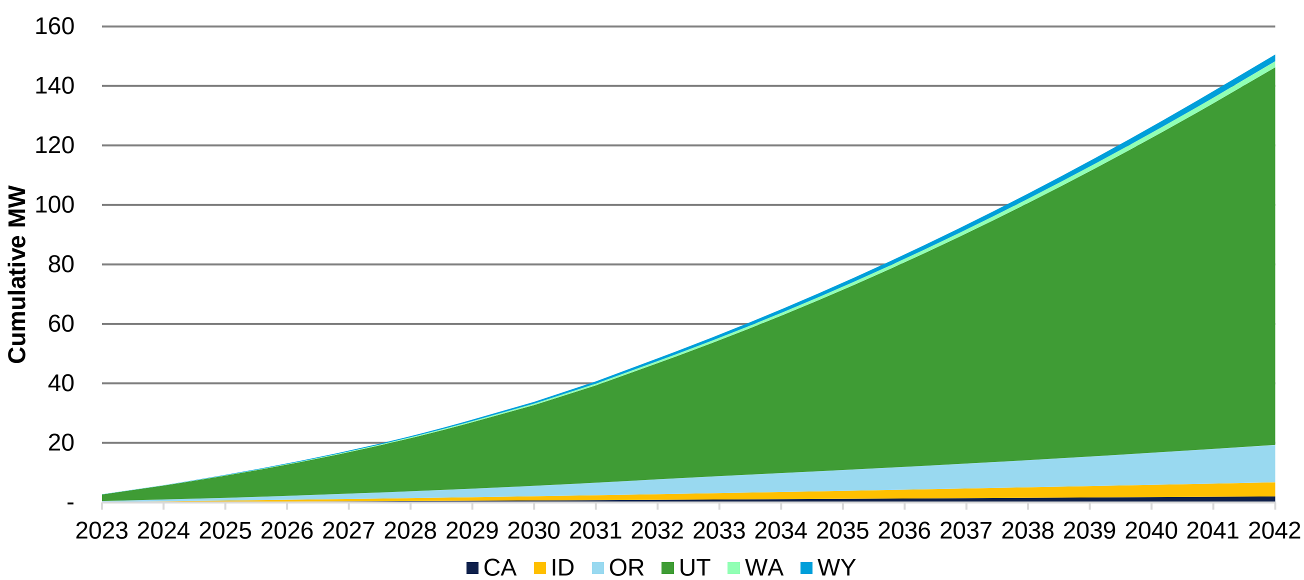
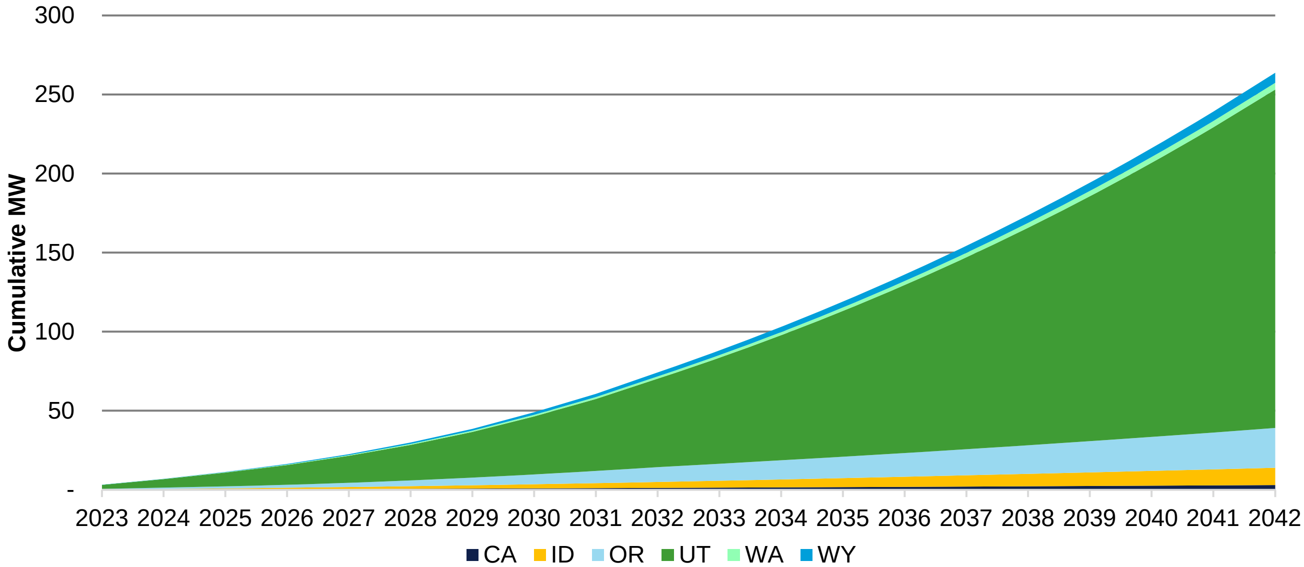


Figure E-7 Cumulative New Battery Storage Capacity Installed by State (MW), 2023-2042, Low Case



[27] https://www.oregon.gov/energy/Incentives/Pages/Solar-Storage-Rebate-Program.aspx

Figure E-8 Cumulative New Battery Storage Capacity Installed by State (MW), 2023-2042, 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 E-9 Cumulative New Battery Storage Capacity Installed by Scenario (MW), California, 2023-2042

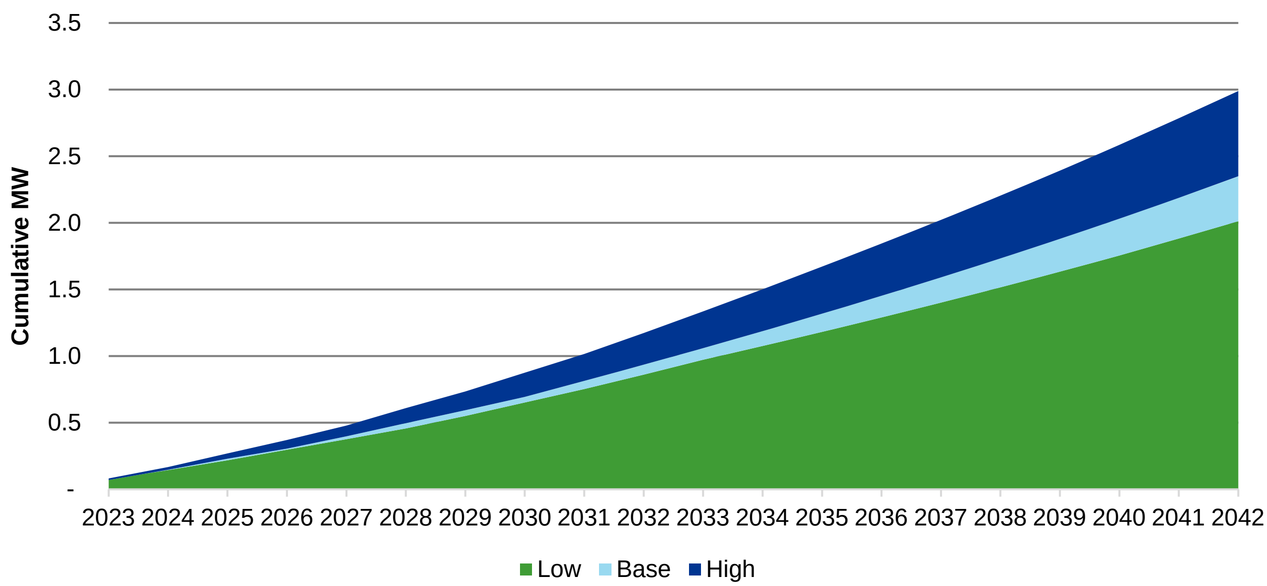
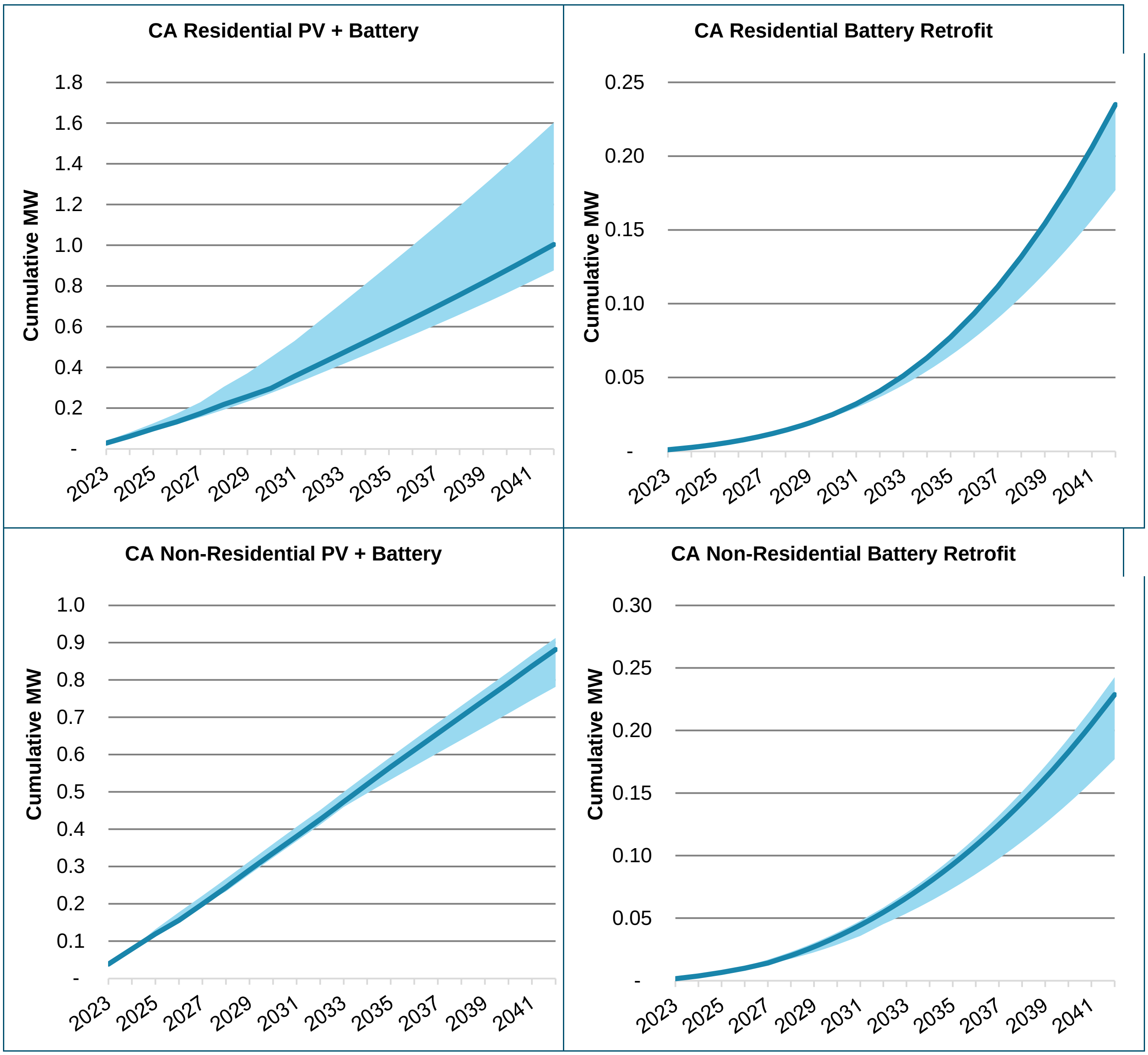


Figure E-10 Cumulative New Battery Storage Capacity Installed by Technology Across All Scenarios (MW), California, 2023-2042

Upper and lower bounds (in blue) represent the high and low case forecasts, with a line for the base case.



Idaho

Figure E-11 Cumulative New Battery Storage Capacity Installed by Scenario (MW), Idaho, 2023-2042

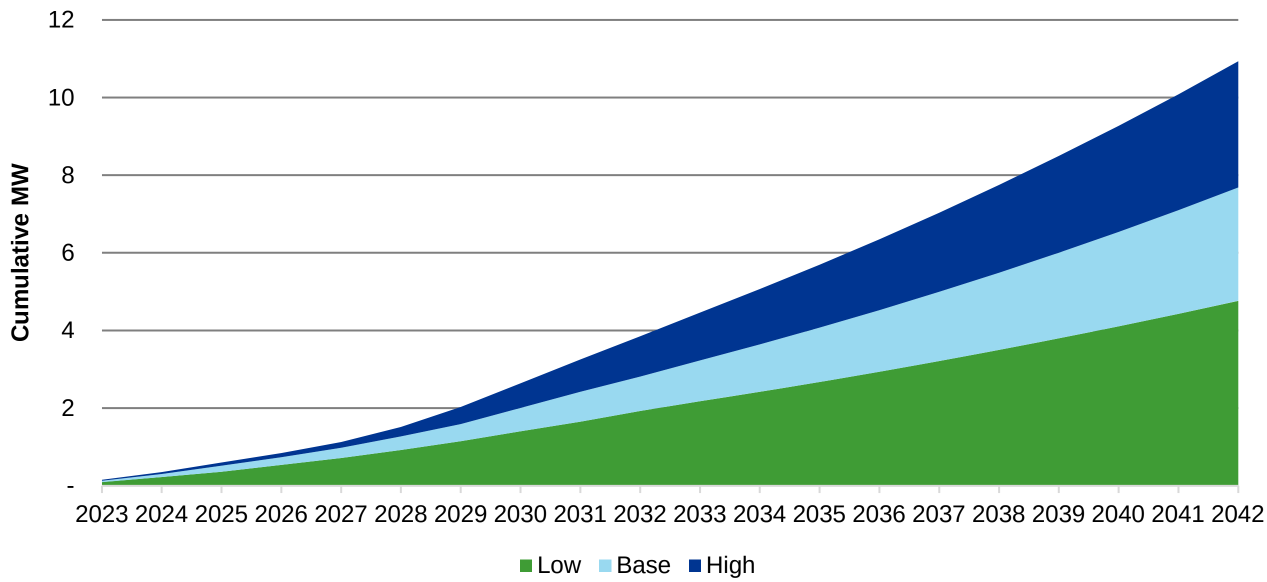
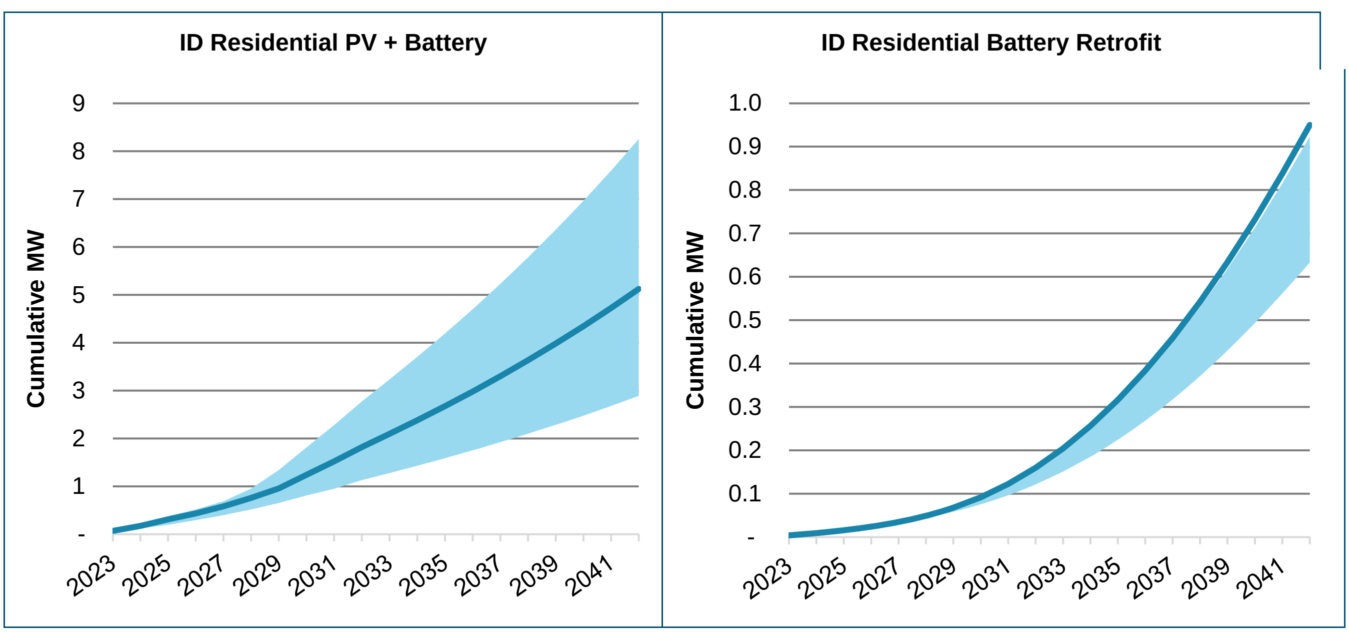
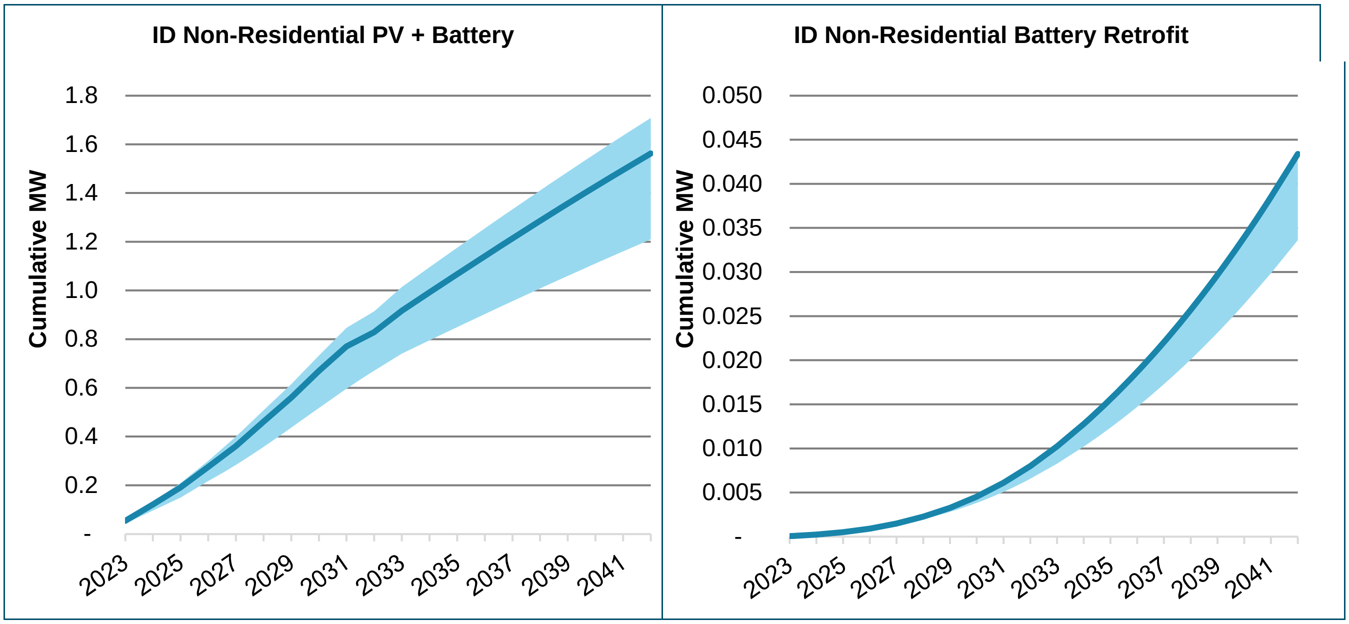


Figure E-12 Cumulative New Battery Storage Capacity Installed by Technology Across All Scenarios (MW), Idaho, 2023-2042

Upper and lower bounds (in blue) represent the high and low case forecasts, with a line for the base case.





Oregon

Figure E-13 Cumulative New Battery Storage Capacity Installed by Scenario (MW), Oregon, 2023-2042

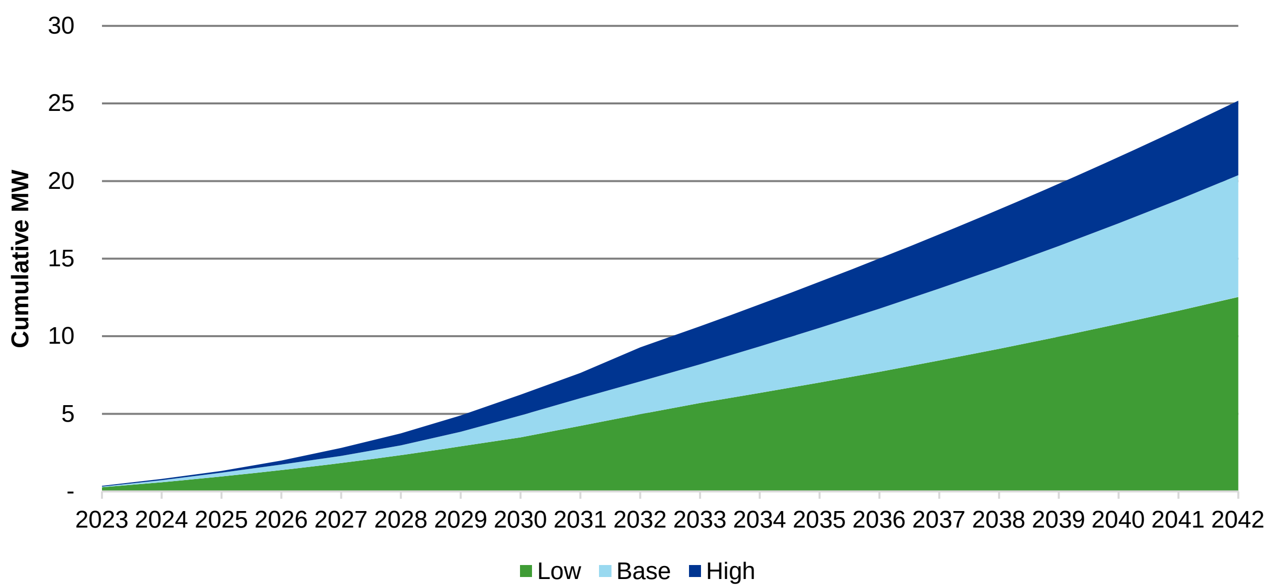
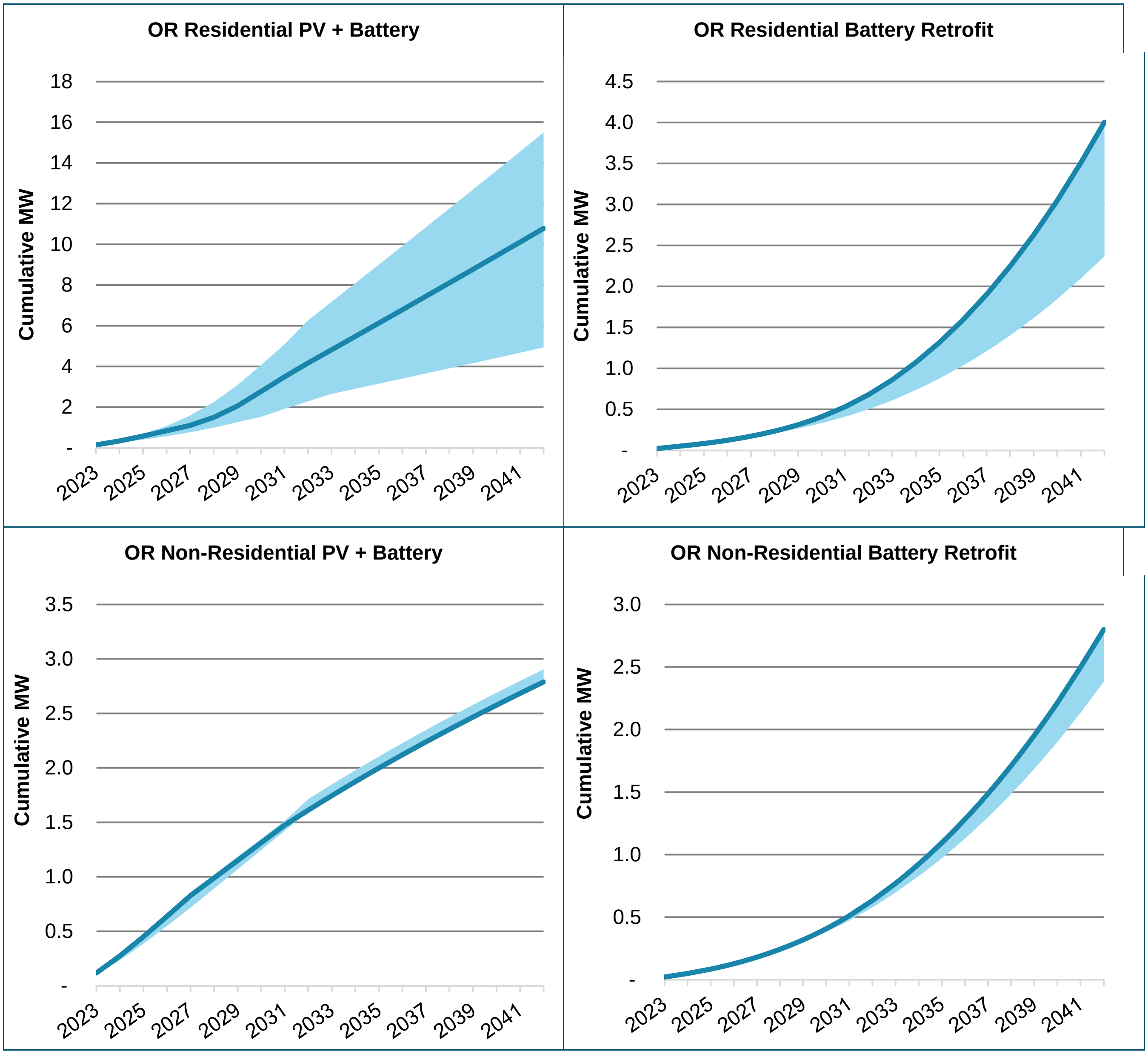


Figure E-14 Cumulative New Battery Storage Capacity Installed by Technology Across All Scenarios (MW), Oregon, 2023-2042

Upper and lower bounds (in blue) represent the high and low case forecasts, with a line for the base case.



Utah

Figure E-15 Cumulative New Battery Storage Capacity Installed by Scenario (MW), Utah, 2023-2042

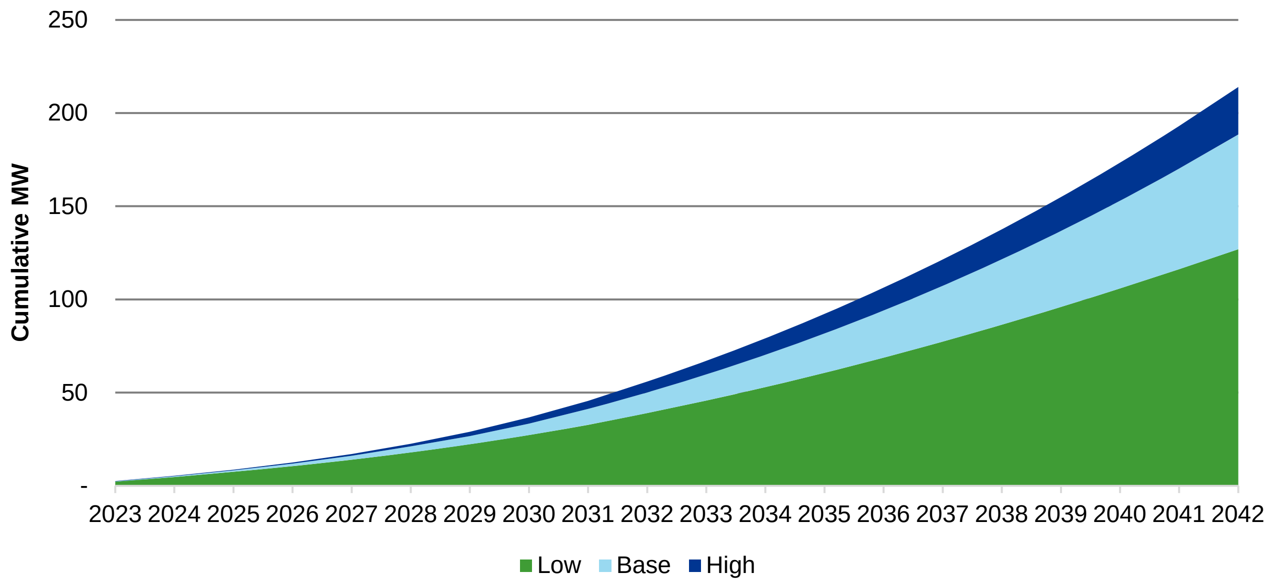
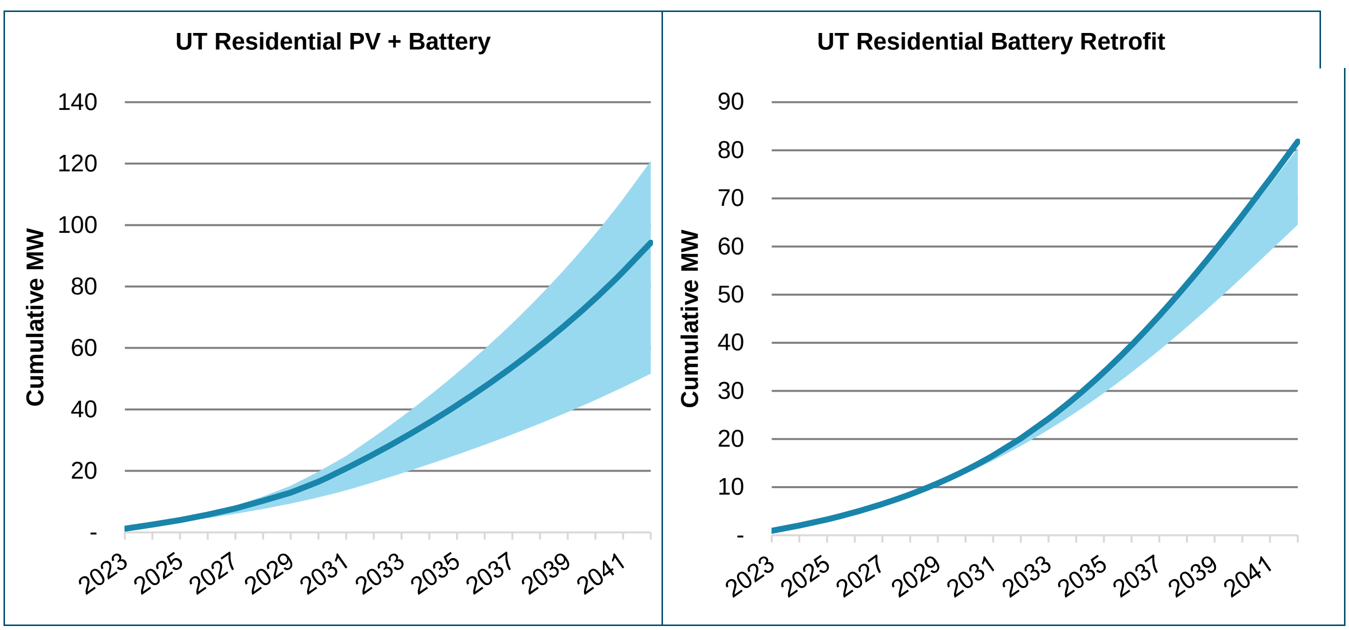
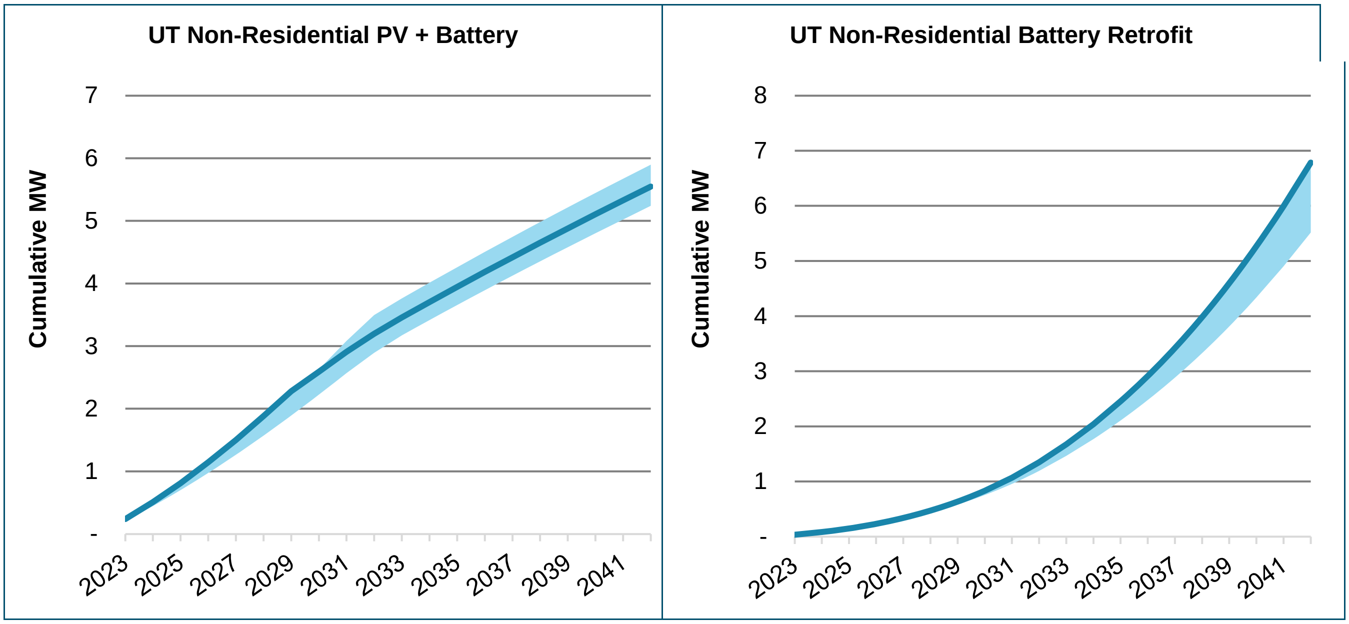


Figure E-16 Cumulative New Battery Storage Capacity Installed by Technology Across All Scenarios (MW), Utah, 2023-2042

Upper and lower bounds (in blue) represent the high and low case forecasts, with a line for the base case.





Washington

Figure E-17 Cumulative New Battery Storage Capacity Installed by Scenario (MW), Washington, 2023-2042

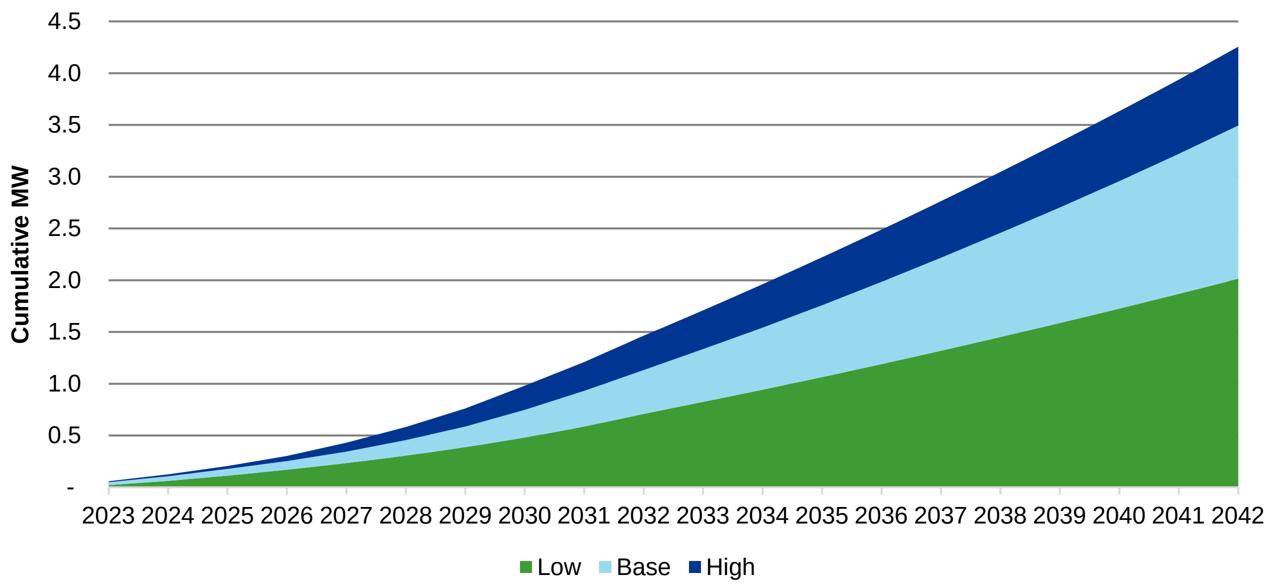
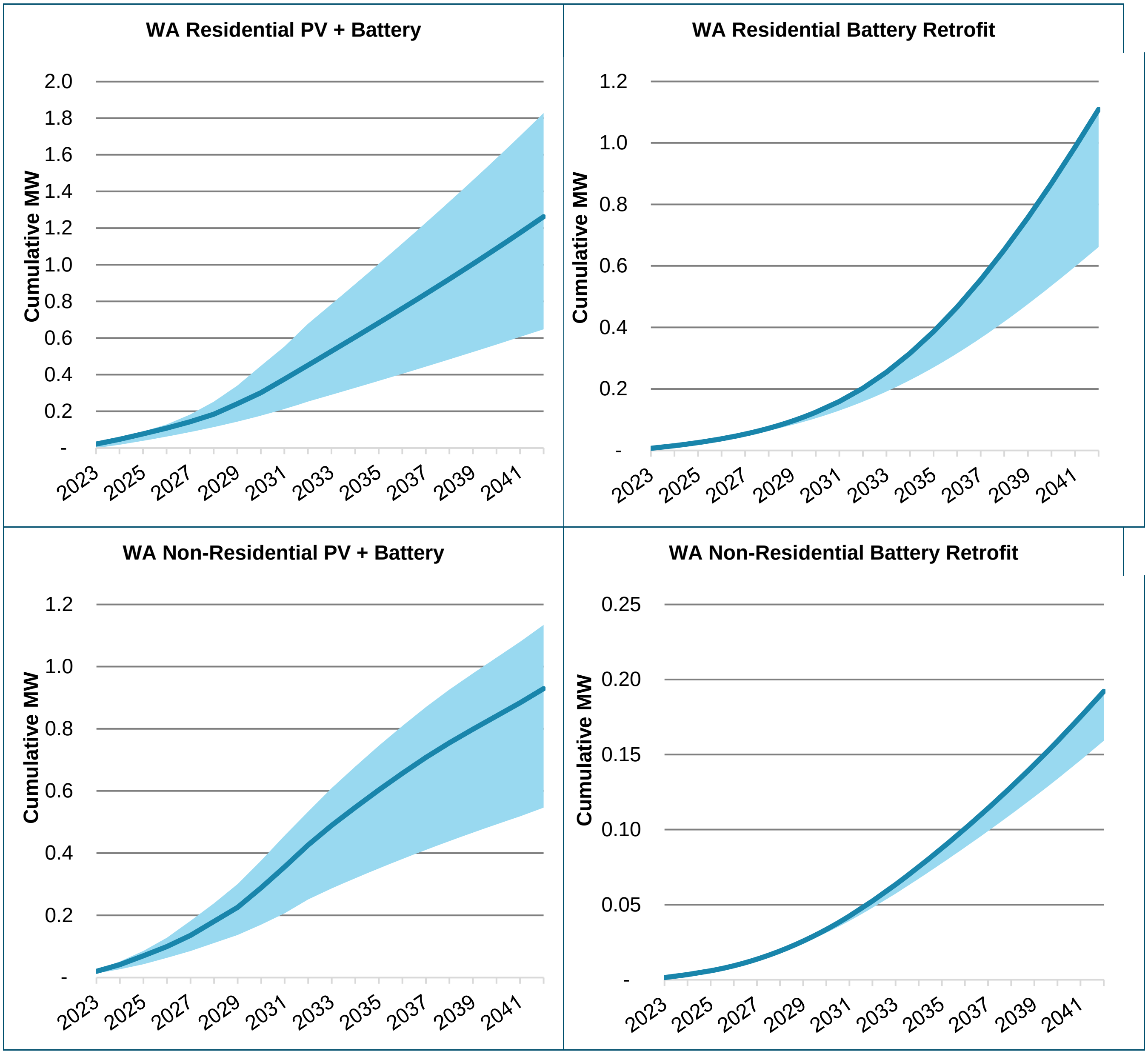


Figure E-18 Cumulative New Battery Storage Capacity Installed by Technology Across All Scenarios (MW), Washington, 2023-2042

Upper and lower bounds (in blue) represent the high and low case forecasts, with a line for the base case.



Wyoming

Figure E-19 Cumulative New Battery Storage Capacity Installed by Scenario (MW), Wyoming, 2023-2042

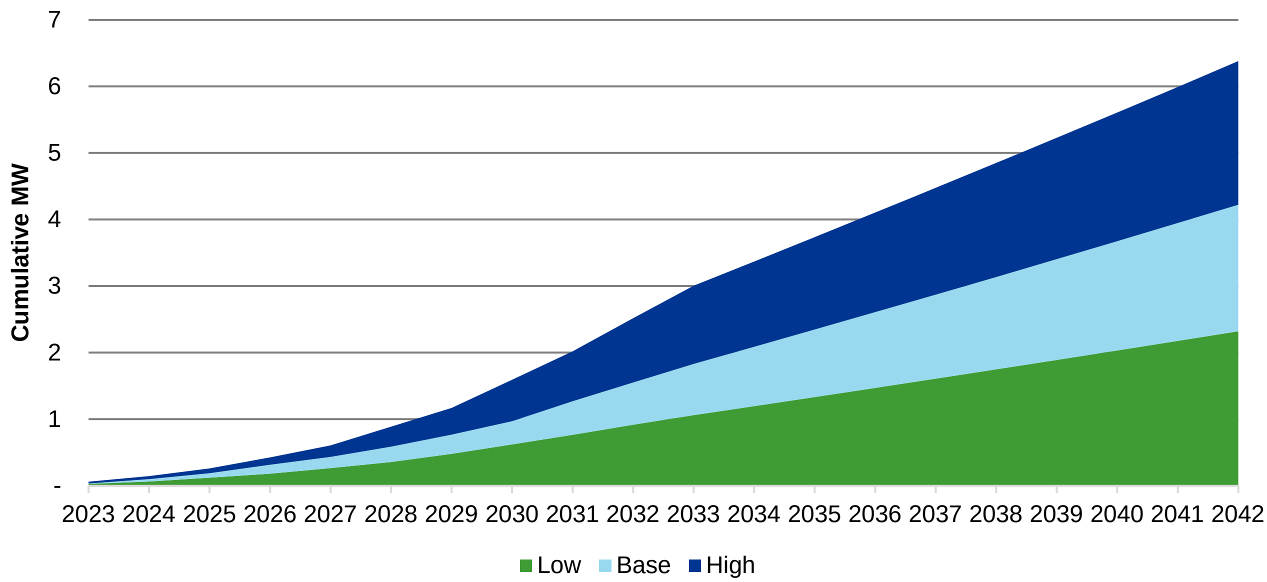
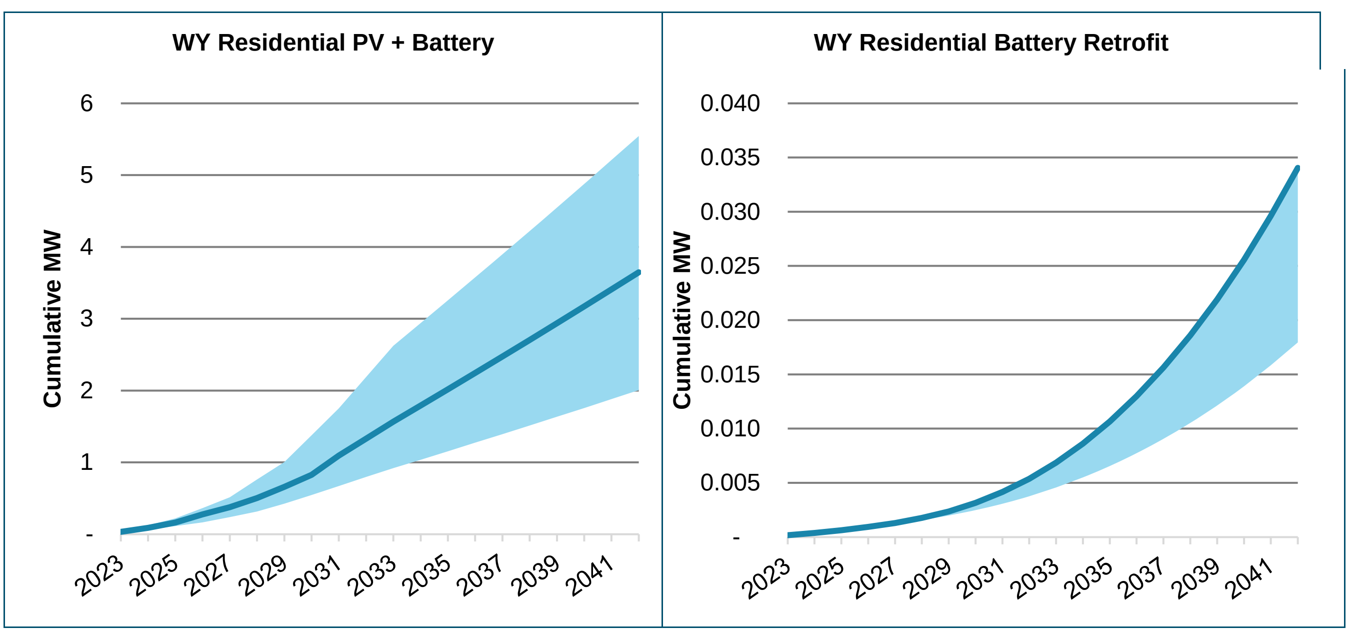
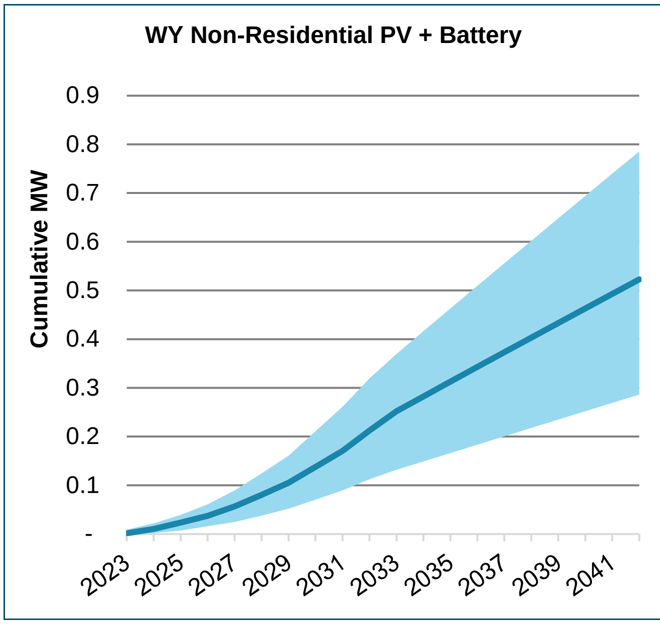
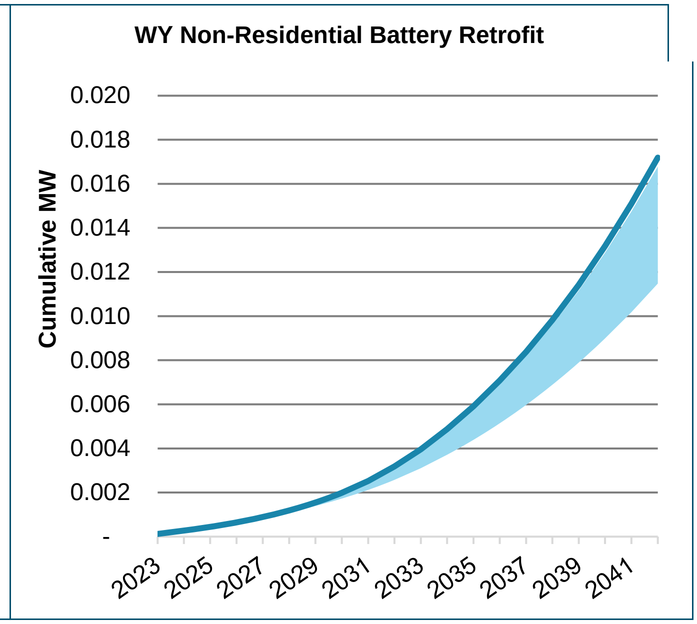


Figure E-20 Cumulative New Battery Storage Capacity Installed by Technology Across All Scenarios (MW), Wyoming, 2023-2042

Upper and lower bounds (in blue) represent the high and low case forecasts, with a line for the base case.




WY Non-Residential PV + Battery
Cumulative MW
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
-
2023
2025
2027
2029
2031
2033
2035
2037
2039
2041


WY Non-Residential Battery Retrofit
Cumulative MW
0.020
0.018
0.016
0.014
0.012
0.010
0.008
0.006
0.004
0.002
-
2023
2025
2027
2029
2031
2033
2035
2037
2039
2041

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APPENDIX M – RENEWABLE RESOURCES ASSESSMENT

A study on renewable resources and energy storage was commissioned to support PacifiCorp's 2023 Integrated Resource Plan (IRP). The "2023 Renewables IRP" Assessment, prepared by WSP is screening-level in nature and includes a comparison of technical capabilities, capital costs, and operations and maintenance costs that are representative of renewable energy and storage technologies. The WSP Assessment builds upon prior studies, updates cost and technical information and adds gravity energy storage options (other than Pumped Hydro Energy Storage, or PHES) and offshore wind (OSW).

This report compiles the assumptions and methodologies used by WSP during the Assessment. Its purpose is to articulate that the delivered information is in alignment with PacifiCorp's intent to advance its resource planning initiatives.

2023 RENEWABLES IRP

PACIFICORP

IRP SUBMITTAL
FINAL

PROJECT NO.: 193579J
DATE: SEPTEMBER 2022

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1 INTRODUCTION

PacifiCorp (Owner) retained WSP to evaluate various renewable energy resources in support of the development of the Owner's 2023 Integrated Resource Plan (IRP) and associated resource acquisition portfolios and/or products. The 2023 Renewable Resources Assessment (Assessment) is screening-level in nature and includes a comparison of technical capabilities, capital costs, and operations and maintenance costs that are representative of renewable energy and storage technologies listed below.

It is the understanding of WSP that this Assessment will be used as preliminary information in support of the Owner's long-term power supply planning process. The level of detail in this study is sufficient to provide screening level data required for the IRP planning process. Past the IRP modeling and selection, technologies of interest to the Owner should be further investigated to refine design, major equipment selection, value engineering, and specific project scope adjustments.

1.1 EVALUATED TECHNOLOGIES

- Geothermal
- Solar
- Wind
    - On-Shore
    - Off-Shore
- Energy Storage
    - Lithium-Ion Battery
    - Flow Battery
    - Gravity Battery
    - Compressed Air
- Solar + Energy Storage
- Wind + Energy Storage
- Wind + Solar + Energy Storage

1.2 ASSESMENT APPROACH

This report accompanies the Renewable Resources Assessment spreadsheet files (Summary Tables) provided by PacifiCorp (PAC) and Burns and McDonnel (BMcD). The Summary Tables are broken out into three separate files for Geothermal, Solar, Wind, and Energy Storage options. Using the assessment for these individual technologies, this assessment also includes technology combinations of Solar + Energy Storage, Wind + Energy Storage, and Wind + Solar + Energy storage. The costs are expressed in mid-2022 dollars for a fixed price, turn-key resource implementation. The Summary Tables can be found in Appendix A: Summary Tables.

This report compiles the assumptions and methodologies used by BMcD, the National Renewable Energy Laboratory (NREL), the Department of Defense (DoE), the International Renewable Energy Agency (IRENA), the Pacific Northwest National Laboratory (PNNL), and existing WSP experience during this assessment. Its purpose is to articulate that the delivered information is in alignment with PacifiCorp's intent to advance its resource planning initiatives. Each technology and grouped technology have been assessed with a ten-year forecast cost trend.

1.3 STATEMENT OF LIMITATIONS

Estimates and projections prepared by WSP relating to performance, construction costs, and operating and maintenance costs are based on experience, qualifications, and judgment as a professional consultant. WSP has no control over weather, cost and availability of labor, material and equipment, labor productivity, construction contractor's procedures and methods, unavoidable delays, construction contractor's method of determining prices, economic conditions, government regulations and laws (including interpretation thereof), competitive bidding and market conditions or other factors affecting such estimates or projections. Actual rates, costs, performance ratings, schedules, etc., may vary from the data provided.

2 STUDY BASIS AND ASSUMPTIONS

2.1 SCOPE BASIS

Scope and economic assumptions used in developing the Assessment are presented below. Key assumptions are listed as footnotes in the summary tables, but the following expands on those with greater detail for what is assumed for the various technologies.

2.2 GENERAL ASSUMPTIONS

The assumptions below govern the overall approach of the Assessment:

- All estimates are screening-level in nature, do not reflect guaranteed costs, and are not intended for budgetary purposes. Estimates concentrate on differential values between options and not absolute information.
- All information is preliminary and should not be used for construction purposes.
- All capital and operations and maintenance (O&M) cost estimates are stated in 2022 US dollars (USD). Escalation is excluded.
- Estimates assume an Engineer, Procure, Construct (EPC) fixed price contract for project execution.
- Capital costs estimates shall be American Association of Cost Engineering (AACE) Class 3 unless otherwise specified.
- Unless stated otherwise, all wind and solar options are based on a generic site with no existing structures or underground utilities and with sufficient area to receive, assemble and temporarily store construction material. Battery options are assumed to be located on existing Owner land.
- Sites are assumed to be flat, with minimal rock and with soils suitable for spread footings.
- Wind and solar technologies were evaluated across five states within Owner's service areas: Washington, Oregon, Idaho, Utah, and Wyoming. The specific locations within each state for potential wind/solar sites were determined by Owner.
- Geothermal technologies were evaluated based on the Owner's existing Dual Flash Blundell Plant and Binary Greenfield Plant.
- All performance estimates assume new and clean equipment.
- Electrical scope is assumed to end at the high side of the generator step up transformer (GSU) unless otherwise specified in Appendix B (most notably for compressed air energy storage).
- AACE Class 5 demolition costs were included for each technology. Costs were developed from published literature from BMcD, NREL, PNNL, DoE, and WSP's experiences; actual rates may vary based on technology and location. Recycling costs are included in the demolition figures; however, re-sale value of materials is excluded as that can vary significantly depending on metals pricing and competition in the currently expanding recycling market. Demolition costs are seen as an optional cost, as Owner could choose other options including repowering the plant.

The current market is being impacted by various trade tariffs on materials as well as on solar modules. Predicting future trends or impacts of these tariffs is beyond the scope of this study. While these costs are intended to represent a snapshot of 2022 pricing, additional volatility could occur when looking at future pricing of these options. These factors may also change the declining costs curves presented in the accompanying spreadsheets.

Energy storage technologies evaluated in this assessment are expected to take advantage of less expensive, off-peak power to charge the system to later be used for generation during periods of higher demand. These storage options provide the ability to optimize the system for satisfying daily energy needs. Energy stored off-peak and delivered on-peak can help reduce on-peak prices and is therefore beneficial to consumers. Additionally, energy storage has a direct benefit to renewable resources as it can absorb excess energy that otherwise would need to be curtailed due to transmission constraints. This could increase the percentage of power generated by clean technologies and delivered during peak hours. Costs and options shown in this assessment represent storage technologies that are designed for one full cycle per day in a scheduled use case. Other use cases such as frequency regulation, voltage regulation, renewable smoothing, renewable firming, and black starting are not accounted for in the options presented in this study. Different use cases will impact the capital cost, O&M, and performance of the various technologies.

The following project indirect costs are included in capital cost estimates:

- Equipment and Materials
- Construction management & Labor Costs
- PII (Permitting, Interconnection, Commissioning)
- Startup spare parts
- EPC Markup
- Owner's contingency
- Builders Risk Insurance
    - Local sales taxes applied to Solar and Wind technologies based on their assumed location.
- Other taxes, such as State taxes, were estimated to current rates and applied based on technology's assumed location.

2.3 OWNER COSTS

Allowances for Owner's costs are not included in the pricing estimates. The cost buckets for Owner's costs are to be determined by PAC. Owner's costs for project development, project management and legal fees vary slightly by technology.

2.4 COST ESTIMATE EXCLUSIONS

The following costs are excluded from all estimates:

- Financing Fees
- Interest during construction (IDC)
- Performance and payment bond
- Off-site infrastructure
- Utility demand costs
- Land Acquisition or Lease costs

2.5 O&M ESTIMATE ASSUMPTIONS

Operations and maintenance (O&M) estimates are based on the following assumptions:

- O&M costs are in mid-2022 USD.
- Nominal 2.5% inflation rate year-over-year
- Fixed O&M Costs
    - Are not dependent on the usage profile of the system
    - Measured in dollars per kilowatt-year ($/kW-yr.)
    - Includes labor costs, fixed maintenance fees, contracted service fees, operational costs, property taxes, land lease, and allowance for future part replacement.
- Variable O&M Costs
    - Are dependent on the usage profile of the system
    - Have been included in fixed O&M costs for all technologies due to limited, inconsistent and/or contradictory public and industry data
    - Includes cleaning and maintenance (scheduled, unscheduled, and general maintenance on technology and transformer(s))

3 GEOTHERMAL

3.1 GENERAL DISCRIPTION

This evaluation, as outlined in the scope of work, includes cost estimates for both Dual Flash expansion of the Blundell Plant, Utah, and general Greenfield Binary Plan (ORC). All cost estimates are based on 200 MW generation with a commercial life expectancy of 40 years or longer. The WSP New Zealand team provided additional help for the Geothermal technology cost estimates, as they have prior experience with both types of plants. The team used a combination of NREL Annual Technology Baseline (ATB) data, International Renewable Energy Agency (IRENA) data, and the "Assessment of Current Costs of Geothermal Power Generation in New Zealand (2007 Basis)" publication from Sinclair Knight Merz for the basis of their analysis. Additional details can be viewed in this deliverable, titles "PacifiCorp Geothermal Project Estimate Support". A summary is provided below.

3.2 PERFORMANCE

All data provided and reviewed from the New Zealand team fits with current industry standards, including reservoir temperature and well production flow rates. The team had to extrapolate costs from 20 and 50 MW scenarios into two 200 MW scenario for the Dual Flash Expansion of the Blundell Plant and the Greenfield Binary Plant, as requested. Additionally, costs had to be converted from $NZ to $US for years 2007 to 2021; based on cost data, project costs were then project to 2022 $US. It is assumed that the Greenfield Binary Plant is in a similar geographic area as the Blundell Plant. Resulting data is provided in Section 3.3.

3.3 COST ESTIMATES

The total capital expenditure (CAPEX) costs for the Blundell Expansion and the Greenfield Binary Plant are $807.66MM and $1,167.99MM, respectively. The primary reason for the discrepancy is the cost of the power plant itself. On a per kW basis, these CAPEX costs result in $4,038 and $5,840 per kW, which both fit within IRENA and NREL estimates. A sample of the EPC cashflow over a 30-month project duration is shown below in Chart 3-1. This cashflow incorporates a relatively slow early construction phase, then spending picks up during the bulk of the construction, followed by a slower pace before the commercial online date in month 31. O&M costs are $23.0MM for both plants. Demolition costs, although very high level given the lack of decommissioned plants, are $23.4MM for both plants. O&M costs for both Dual Flash Blundell and Greenfield Binary Plants, represented for 2022, is $115.00/kW-yr. which falls within a close range of NREL's $105.562/kW-yr. as referenced in Chart 3-2.

Chart 3-1 Geothermal EPC Cashflow

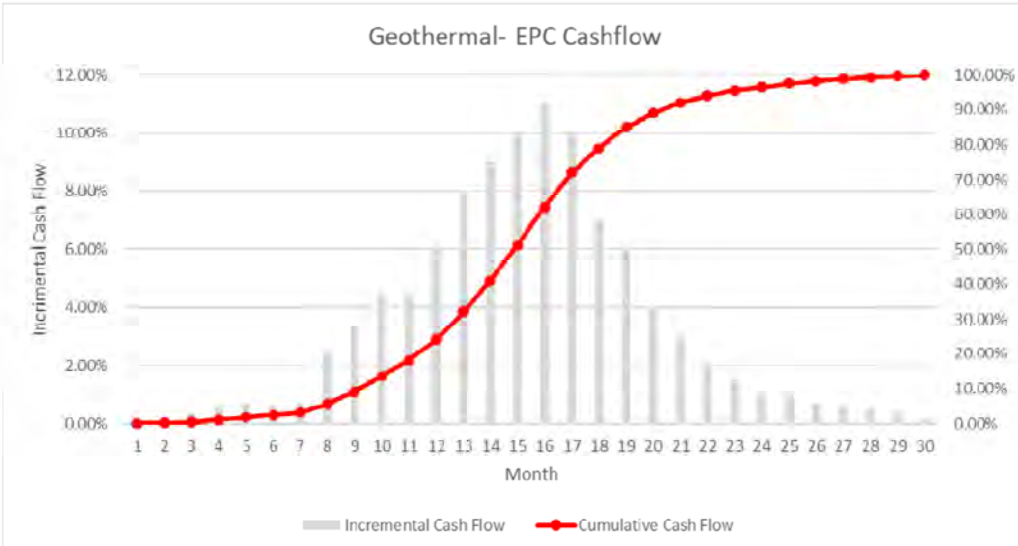
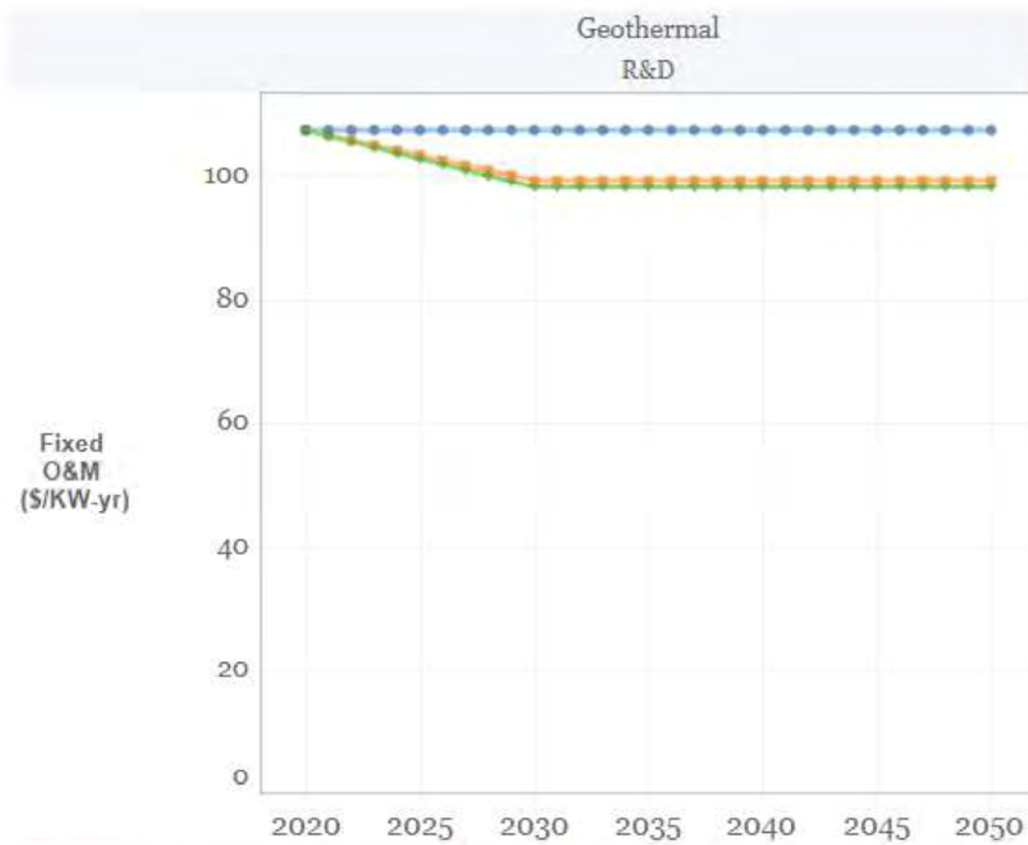


Chart 3-2 Geothermal O&M Cost Trends



Source: "Electricity Annual Technology Baseline (ATB)", NREL, 2020

4 SOLAR PHOTOVOLTAIC

4.1 INTRODUCTION

This evaluation, as outlined in the scope of work, includes cost estimates for both 20 and 200 MW AC single-axis tracking photovoltaic (PV) systems both with a 1.3 DC-AC ratio. All cost estimated are on an AC-capacity basis. PacifiCorp provided performance characteristics of the various location including AC capacity factor, 25-year commercial life, module degradation, and annualized energy production. The five project locations span across PacifiCorp's service territory, as shown below:

Rocky Mountain Power	Pacific Power
Idaho Falls, Idaho	Lakeview, Oregon
Milford, Utah	Yakima, Washington
Rock Springs, Wyoming	

4.2 COST ESTIMATING METHODOLOGY

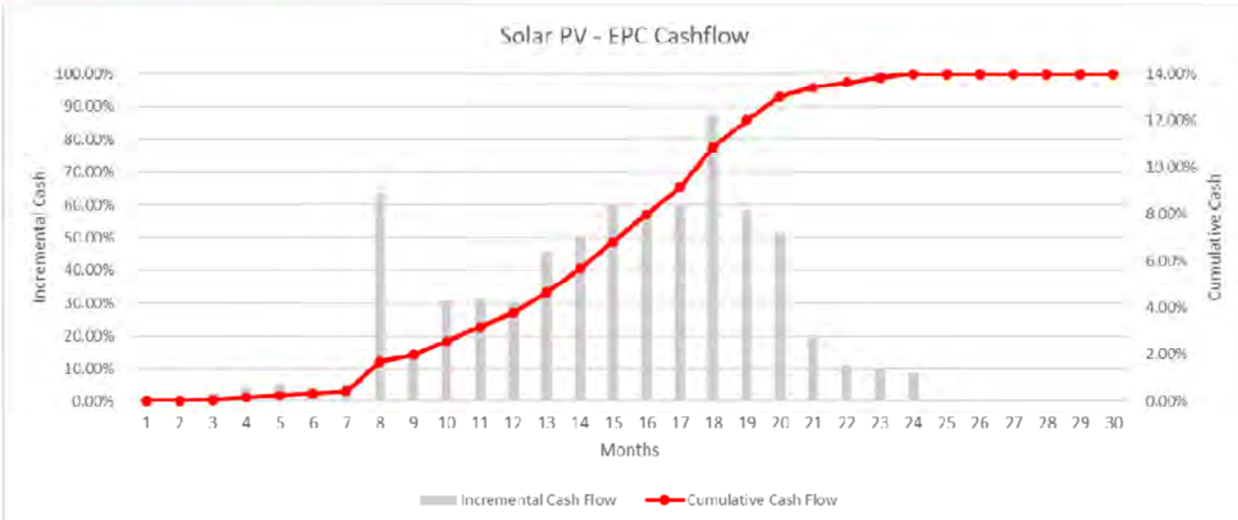
Cost estimates for this evaluation were based upon widely used public information, including the National Renewable Energy Laboratory (NREL), Solar Energy Industries Information (SEIA) data, Lawrence Berkeley National Laboratory (LBNL or "Berkeley Lab"), Pacific Northwest National Laboratory (PNNL), previous WSP project proposals and internal databases, as well as original equipment manufacturer (OEM) and EPC quotes. Locational adjustment factors for the five project locations are from the U.S. Energy information Administration's (EIA) utility-scale capital cost estimates. All publicly available data used for these estimations is found in the bibliography.

EPC overnight project capital costs are presented in 2022 dollars. These costs include the modules, inverters, structural/electrical balance of system (BOS), installer overhead/Labor, and EPC overhead (equipment and material). Additionally, owner's costs include engineering/development overhead, transmission interconnection fees, permitting costs, and developer profit. It is assumed that PacifiCorp will provide the owner's project management, development, and legal cost data points. Overnight capital cost estimations for projects built in future years is shown in Appendix A.

Operations and maintenance costs are presented in 2022 dollars. These costs include cleaning, vegetation management, inspection, replacement, taxes, insurance, asset management, land leases, and operations administration. These costs are calculated as flat yearly rates, and do not change based on the energy output of the system, for the respective system capacity sizes. It is assumed that the land for all five project locations is leased throughout the project lifetime. As land lease rates vary within a single site location, this line item has been reserved for Owner input. Project demolition costs are provided in 2022 millions of dollars, based on multiple publications quoting $30,000 per MW. As noted above, demolition costs are very uncertain, and this estimate does not include the potential to re-sell any equipment.

Total EPC costs are similar for all locations with a 20 MW AC capacity with a range of $21.24-$22.91. This is similarly the case for the 200 MW AC systems, with a range of $174.35-$188.07MM. These costs align with the literature and previous project experience analyzed for this report, which falls between $1,300-$1,400/kW. Although the cost of solar PV development has steadily declined over the past two decades, recent U.S. tariffs along with price increases related to supply-chain shortages and worldwide inflation have provided more uncertainty on cost estimations. WSP believes the projections in this report fall within +/- 30% of the true cost, as is consistent with an AACE Class 4 cost estimate classification system. Estimated EPC cash-flow values for solar PV are shown below in Chart 4-1. This chart shows the low spend months during pre-construction, followed by large spends on procurement. The next phase is the bulk of the construction, with that process finishing in month 24 resulting in a commercial online date in month 25. Ten-year CAPEX and O&M cash-flow estimations are provided for all locations in the accompanying spreadsheets. These also include ten-year trend tables for overnight CAPEX estimations.

Chart 4-1 EPC Cashflow



4.3 ASSUMPTIONS

All assumptions not stated thus far for solar PV cost estimates are provided below. Please see Appendix A for a full list of solar PV assumptions:

- Third party long-term service agreement O&M costs are included in the "asset management and security" line item.
- It is assumed that the 20 and 200 MW AC PV systems will take up a 160- and 1600-acre footprint, respectively. The land lease is assumed to be $55,000 and $547,000 yearly cost, respectively.
- Owner's contingency (3%) and Builders Risk Insurance (0.317%) were developed from available literature and previous project history. These values represent the stability of the technology and thus vary for different technologies. PacifiCorp should review these values and update them as necessary.
- State tax assumptions were provided by PacifiCorp and implemented based on available literature. Pollution control values were omitted as the applicability of the tax is hard to define and is heavily location dependent. Owner should assess this tax separately for each location.
- WSP retained fewer OEM quotes than expected, and although the available ones fit with the report outputs, Owner should engage in vendor outreach for more detailed EPC values and delivery times.

5 WIND

5.1 ON-SHORE

5.1.1 GENERAL DISCRIPTION

The purpose of wind turbines is to convert the kinetic energy in the wind to rotational motion of the turbine itself. This rotary motion is then converted to electrical power that can be distributed across the grid. Wind turbine technology in its modern form is a mature technology, with over 50 years of research and operation behind it. Modern wind turbine designs are classified into two unique sub-sets:

1. Horizontal-axis wind turbines, which operate with the axis of rotation parallel to the prevailing wind direction.
2. Vertical-axis wind turbines, which operate with the axis of rotation perpendicular to the prevailing wind direction.

Almost all utility scale wind turbines constructed today are horizontal-axis turbines. These turbines consist of four main components: rotor, drivetrain, nacelle, and tower. The rotor consists of the turbine blades and the hub on which the blades are mounted, which transfers rotational energy to the drive train. The drivetrain utilizes a gearbox and rotary shafts to transfer power to the electrical generator. The nacelle houses the drivetrain and all other electrical components at the top of the tower, while the tower supports the rotor and nacelle at the prescribed height of the turbine.

The power available to be extracted from the wind is a function of the cube of the wind speed. As a result, if the wind speed were to double the available power would increase by a factor of eight. However, the ability of the turbine to extract this power is directly corelated to the area swept by the rotor blades. Thus, the two most important factors when considering the output of a potential wind energy project are the wind speed at the location and the size of the turbine.

5.1.2 PERFORMANCE

The wind resource assessment and capacity factor analysis of five different onshore sites in Idaho, Oregon, Utah, Washington, and Wyoming are summarized in this section. Generic project locations were selected in the area specified by owner.

The NREL's publicly available wind data source is utilized to perform a desktop study to determine the relative availability of wind resources in each site. The wind resource data is extracted for three fiscal years at 100m height. The wind resource assessment is performed based on 1-hour wind data. WSP selected the GE 3.4-137 wind turbine for this analysis. The wind turbine specifications are presented in Table 1. The maximum tip height of this turbine is under 500 feet, which means there are less likely to be conflict with the Federal Aviation Administration (FAA) altitudes available for general aircraft. One generic power curve at standard atmospheric conditions for each of the sites was assumed for the GE3.4-137.

Table 1 Wind Turbine Specifications

Rated power	3400 kW
Rotor Diameter	137m
Hub Height	85m
Blade Length	67.2m
Maximum Tip Height	153.5m

The Annual Energy Production (AEP) was estimated for five different sites. The wind speed data is adjusted to the wind turbine hub height before the power production assessment. The equation below is used for estimating the wind speed at hub height:

$$V_h = V_d \left(\frac{H_h}{H_d}\right)^{\alpha}$$

Where V_h is the wind velocity at wind turbine hub height, V_d is the dataset wind speed value at 100m height, H_h is the wind turbine hub height, H_d is the height wind speed dataset (100m), and α is the wind shear factor. We assumed that the wind shear factor is 0.15 in this analysis.

Table 2 shows the summary of gross and net annual capacity factors for each site. The annual losses for each wind site were assumed as 15 percent, which is a common assumption for screening level estimates in the wind industry. This loss factor was applied to the gross capacity factor estimates to derive a net annual capacity factor for each potential site.

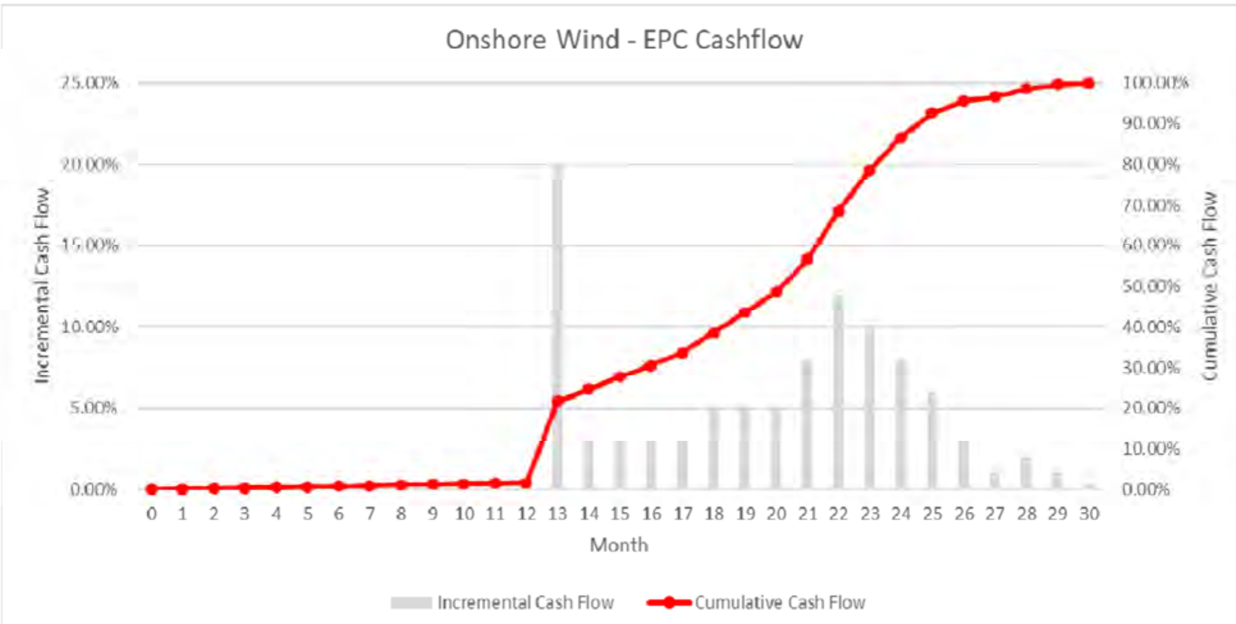
Table 2 Onshore Wind Annual Gross & Net Capacity

	GE 3.4 MW		
Location	Gross Annual Energy Production (GWh)	Net Annual Energy Production (GWh)	Net Capacity Factor
Pocatello, ID	8.841	7.515	25%
Arlington, OR	13.742	11.681	39%
Monticello, UT	13.952	11.859	40%
Goldendale, WA	10.745	9.133	31%
Medicine Bow, WY	17.175	14.599	49%

5.1.3 COST ESTIMATES

The Capital Expenditure (CAPEX) and Operation Expenditure (OPEX) estimations of each wind energy project is summarized in Appendix A. WSP referenced internal and public information to derive the cost estimates, and the CAPEX value ($/kw) aligns with the latest 2022 DoE land Based Wind Market report of ~$1,500/kw, which is 7-10% higher than the previous year due to inflation & supply chain constraints. The OPEX costs, were derived from the NREL 2022 ATB ($43/kw-yr.). Chart 51 below shows an estimation of EPC cashflows for onshore wind, with a slow start to spending during preconstruction and a large procurement guarantee followed by the majority of construction in months 14-30. It is assumed that the commercial online date would begin in month 31. The decommissioning costs are meant to represent the efforts to return the project site back to native conditions. This includes the decommissioning and demolition of all wind turbines as well as the associated infrastructure. Also included is the transportation cost associated with moving the turbines off-site to recycling or landfill locations. As shown in Chart 5-1, the decommissioning cost for 20MW wind farm is $1.19MM and for 200 MW wind facility costs $11.89MM to demolish the wind farm.

Chart 5-1 Onshore Wind EPC Cashflow



5.2 OFF-SHORE

5.2.1 GENERAL DISCRIPTION

Offshore regions of the United States boast some of the strongest and most consistent wind resources currently available. These higher average wind speeds offer a more consistent form of clean energy production than their onshore counterparts. To capture these resources wind turbines must be constructed in waters ranging from 50 to over 1000 feet (300m) in depth, which provides unique challenges. However, innovations in underwater foundation construction and transmission have made offshore wind a viable and attractive energy source.

5.2.2 PERFORMANCE

Like the onshore wind sites, the NREL's publicly available wind data is used for the wind resource assessment and power factor estimation of offshore wind facility. The site location is at West of Klamath River, CA, which was selected in the area specified by owner. WSP selected the GE 6-150 wind turbine for this analysis. The wind turbine specifications are presented in Table 3. A summary of the gross and net annual capacity factors of the offshore wind facility is presented in the Table 4.

Table 3 Wind Turbine Specifications

Rated power	6000 kW
Rotor Diameter	150m
Hub Height	100m
Blade Length	73.5m
Maximum Tip Height	173.5m

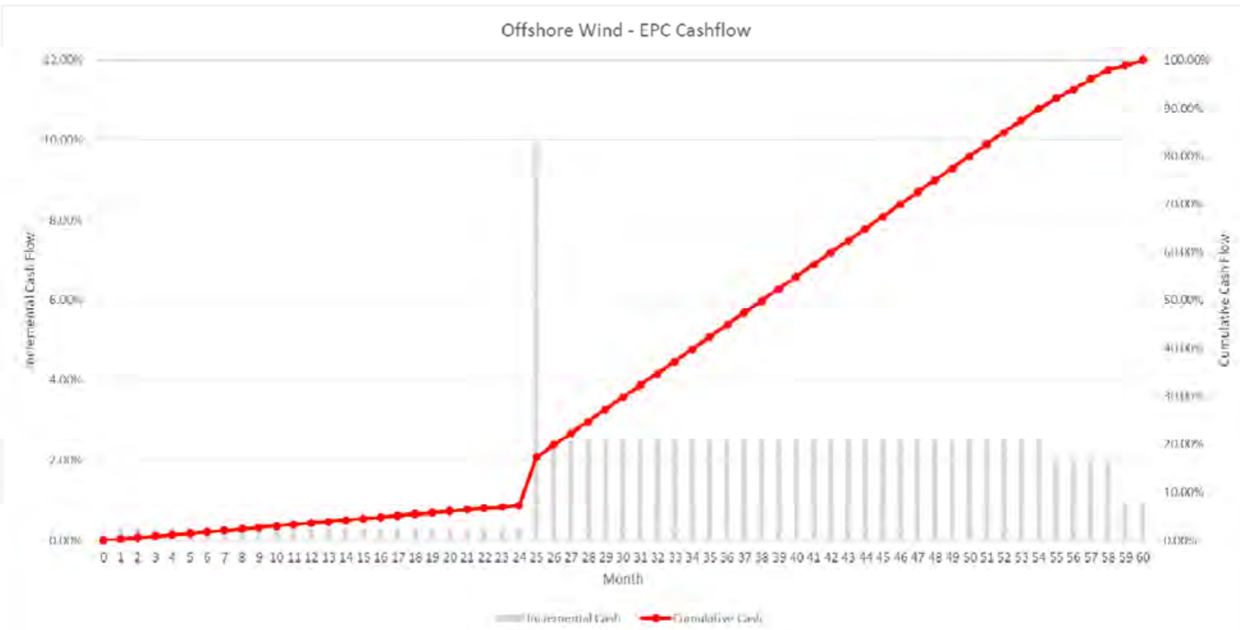
Table 4 Offshore Wind Annual Gross & Net Capacity

	GE 6.0 MW		
Location	Gross Annual Energy Production (GWh)	Net Annual Energy Production (GWh)	Net Capacity Factor
West of Klamath River, CA	29.002	24.652	47%

5.2.3 COST ESTIMATES

The cost estimation summary of CAPEX and OPEX of offshore wind site is shown in Appendix A. The entire cost estimation of offshore wind facility is referenced from NREL's 2022 IRP report for the cost of offshore wind in California and are assuming the Offshore wind farm is in the Humboldt Call Area. Similar to onshore wind, offshore wind sees a slow increase of cash flows in the first stages of the project. In this case, this phase lasts about two years. Then, there is the large procurement payment followed by three years of construction. It is assumed that the commercial online date is in month 61. The decommissioning cost without locational adjustment factor is $31.6MM for a 200 MW, and $158.23MM for a 1,000 MW offshore wind facility.

Chart 5-2 Offshore Wind EPC Cashflow



6 ENERGY STORAGE

Energy storage is a rapidly developing field with technologies at a different stage of maturity. While some are established and allow the development of relatively high-fidelity project budget estimates (e.g., Li-Ion battery), others are only undergoing initial commercial roll-out (e.g., gravity energy storage, compressed air energy storage) and therefore their cost and technical performance can be expected to significantly change over the next 5 years. Please see Appendix B for side-by-side comparison of the key technical parameters of the energy storage technologies included in this Report.

6.1 LITHIUM-ION

6.1.1 GENERAL DISCRIPTION

Aside from pumped hydro, Li-Ion battery energy storage is currently the most established and proven energy storage technology for grid-scale applications. This analysis is focused on systems utilizing LiFePO4 (LFP) battery chemistry, which have recently become dominating in this space. A relatively standardized set of technical parameters has been developed by utilities and there are many vendors offering substantially similar systems, allowing for robust competition. Regulatory compliance requirements are still evolving but generally well-understood by vendors and EPCs. Contractual technical support schemes such as Long-Term Service Agreements (LTSA) have been developed and implemented on numerous projects. A solid track of record of performance has been established both for the technology itself as well as for the leading OEMs. At the same time, recent supply chain challenges, relative scarcity of raw materials, shortages of manufacturing capacity and competition from the transportation sector with its rapidly increasing demand for Li-Ion cells and systems lead to increasingly long lead times for the Li-Ion battery systems and prevent the realization of the forecasted decrease in the per/kWh energy storage cost using this technology.

6.1.2 PERFORMANCE

Li-Ion based energy storage systems are well-suited for grid-tied systems designed for daily cycling including load shifting, demand response, peak shaving, and rapid response grid support applications such as voltage and frequency support. Li-Ion systems projected to last 15 to 20 years before decommissioning or re-powering projects. Due to calendar and cycle-driven capacity degradation they typically require several capacity augmentations events throughout their lifetime on order to maintain nameplate performance. Reference Appendix B for side-by-side comparison of the key technical parameters of Li-Ion battery systems with other energy storage technologies included in this Report. Below are EPC cash flow estimates for the battery equipment (storage block and power equipment) and the rest of the EPC line items. As shown, the equipment cash flow requires a high up-front payment, which has become more standard in recent years. The following payments make up the rest of the total cost, but many manufacturers require that early commitment to guarantee their product will be used. The EPC cash flow starts reasonably slow, and then has three spikes of large payments for the various other EPC inclusions. These cash flow estimates are for lithium-ion batteries and the percentages were provided by PacifiCorp, assuming a two-year project duration before the commercial online date in month 25.

Chart 6-1 Energy Storage - EPC Cashflow

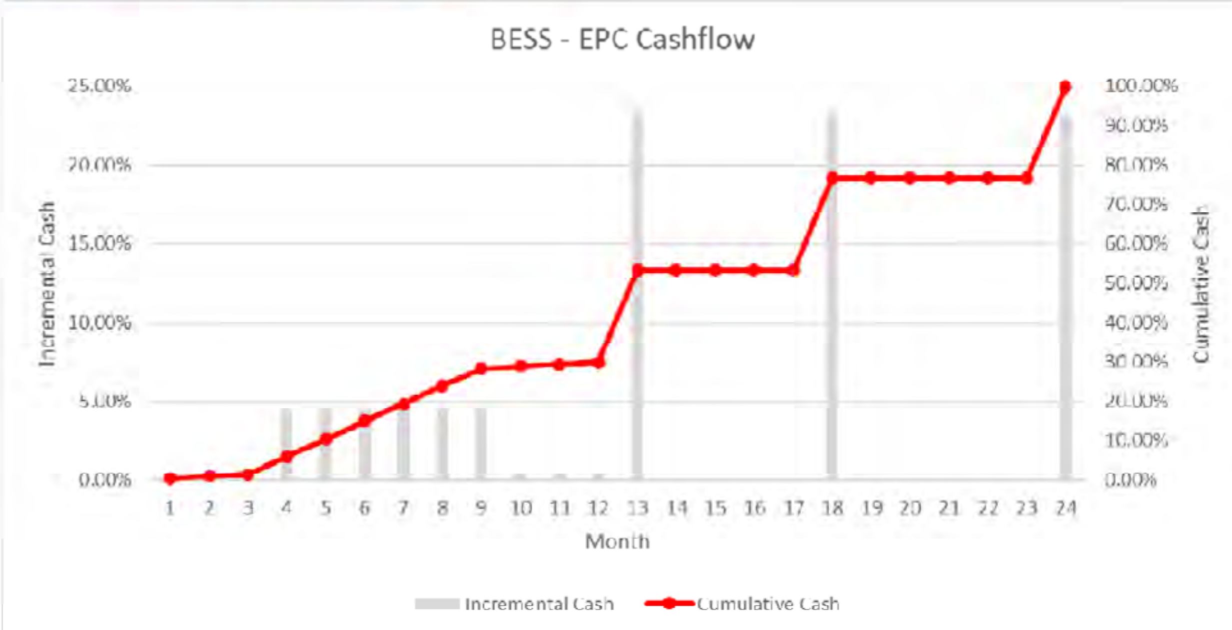


Chart 6-2 Energy Storage – Equipment Cashflow

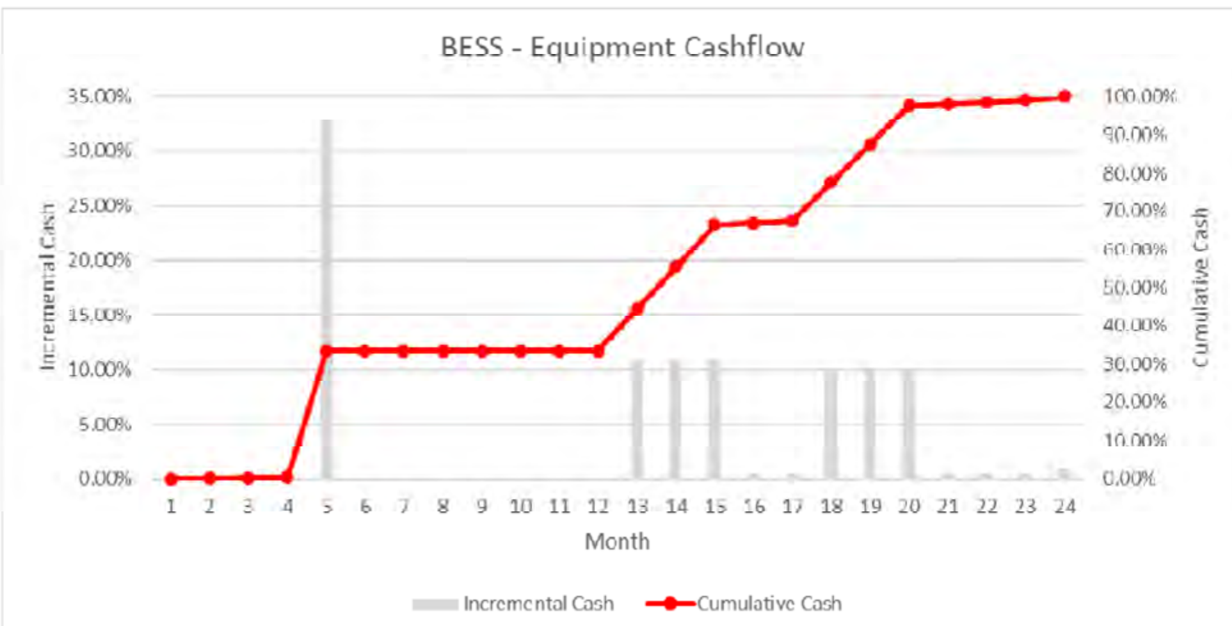


Chart 6-1 and 6-2: Cash-flow percentages derived from previous WSP and PAC projects, along with current industry standards. Equipment costs include the storage block and power equipment, EPC costs include all other EPC line items from the Energy Storage spreadsheet. Assuming project duration of 2 years.

6.2 FLOW BATTERY

6.2.1 GENERAL DISCRIPTION

Flow Batteries utilize electrolyte solution that changes its chemical state when flowing through a cell. This change is reversible and is accompanied with consumption or release of energy. Large volumes of electrolyte are stored in tanks designated for high and low energy states of the system (State of Charge). This technology allows a significant reduction of the cost of cells with their electrodes, easy upgrade or change of electrolyte without exchanging cells and changing electrodes without affecting electrolyte, limited capacity degradation that is also easier to manage and the resulting longer life span and lower lifetime costs as compared to Li-Ion batteries.

Flow batteries are relatively new technology with only few established OEMs and a limited number of full-scale commercial installations and limited track record. Several competing chemistries exist with significantly different technical parameters, with no clear leader established at time of writing this report. A standardized set of technical parameters has not yet been developed by utilities. Regulatory compliance requirements are still evolving and may not yet be fully well-understood by vendors and EPCs. Contractual technical support schemes such as Long-Term Service Agreements (LTSA) have been developed but have seen very limited implementation to date.

Lower projected lifetime costs as compared to Li-Ion, very linear performance through the entire state of charge (SoC) range, easy scalability, and the ability of flow battery systems to cost-effectively provide longer-duration energy storage (8-24 hrs.) position this technology as an emerging competition to Li-Ion-based systems.

6.2.2 PERFORMANCE

Flow energy storage systems are well-suited for grid-tied systems designed for daily (especially longer-duration) cycling including load shifting (especially for wind), short- and long-term demand response, peak shaving, and some grid support applications. Flow battery systems are projected to last between 12 and 50 years (depending on chemistry) before decommissioning or re-powering projects. They do not require capacity augmentation events (aside from electrolyte change) during their lifetime on order to maintain nameplate performance and do not have a lifetime cycle limit. Their response time and ramp rate are typically slower than Li-Ion batteries, and they do have a marked difference between "hot" and "cold" standby modes and the resulting response times. In some applications flow battery systems can provide significant advantages as compared to Li-Ion; however, a careful attention must be paid to key differences from Li-Ion and the resulting potential limitations for other applications. A project-level analysis of critical performance requirements is recommended prior to considering this technology. Please see Appendix B for side-by-side comparison of the key technical parameters of flow battery systems with other energy storage technologies included in this Report.

6.3 GRAVITY ENERGY STORAGE

6.3.1 GENERAL DISCRIPTION

Gravity energy storage is an emerging technology that uses the differential of potential energy of a body of a large mass (solid or liquid) depending on its elevation on the Earth's gravity field as the means to store energy. This potential energy is converted into kinetic energy driving a generator to extract the stored energy (to discharge it). Conversely, kinetic energy of electric motors is used to increase the potential energy state of this system (to charge it). Technically, the well-established pumped hydro is a form of gravity storage. New systems being rolled out use solid weights (in elevated structures or in deep shafts), water in deep shafts, or a combination of the two (a solid piston creating water pressure).

Gravity energy storage is a new technology with only few established OEMs and a limited number of commercial pilot installations, and a very limited track record. At the same time, the basic physics behind these systems is very well understood and most of the required equipment is off-the-shelf industrial systems. This means that most of the risk lays in implementation rather that technology itself. A standardized set of technical parameters has not yet been developed by utilities; however, it can be easily modeled after pumped hydro. Regulatory compliance requirements are still evolving but are expected to fall within existing categories of heavy construction machinery. Contractual technical support schemes such as Long-Term Service Agreements (LTSA) have not yet been developed.

Advantages of gravity storage systems include extremely long lifespan low lifetime costs, very linear performance through the entire state of charge (SoC) range, easy scalability, and the ability to cost-effectively provide longer-duration energy storage (from days to weeks or months). If thought of in terms of this being a variation of pumped hydro, it should be relatively easy to assess applicability of this technology to specific project needs and develop a set of key technical parameters.

6.3.2 PERFORMANCE

Gravity energy storage systems are well-suited for grid-tied systems designed for daily (especially longer- and very long-duration) cycling including load shifting (especially for renewable generating resources with long-term variability such as wind), long-term demand response, peak shaving, and some grid support applications. Gravity systems are projected to last longer than 40 years before decommissioning or re-powering projects. They do not require capacity augmentation events during their lifetime on order to maintain nameplate performance and do not have a lifetime cycle limit. Their response time may be slower than Li-Ion batteries but like pumped hydro, a project-level analysis of critical performance requirements is recommended prior to considering this technology. Please see Appendix B for side-by-side comparison of the key technical parameters of gravity energy storage systems with other energy storage technologies included in this Report.

6.4 COMPRESSED AIR ENERGY STORAGE (CAES)

6.4.1 GENERAL DISCRIPTION

Compressed Air energy storage (CAES) is an emerging technology that uses large volumes of compressed air as the means of energy storage. To charge the system, electrically driven compressors fill a designated air storage container (such as underground cavern, underwater bladders, etc.) To discharge the system, the compressed air is routed to turboexpanders that drive electric generators. A recent variation of the technology is Adiabatic CAES (A-CAES) which recovers the heat produced during compressing the air into a thermal storage system; this energy is then used to reheat the air during expansion cycle, significantly improving system round-trip efficiency. The technology uses a lot of relatively standard turbomachinery based on gas turbine and industrial gas handling systems. One of the variations of A-CAES technology currently in the pilot stage uses CO_2 as a working fluid, enabling a theoretically higher system efficiency but requiring large storage for unpressurized CO_2.

CAES is a new technology with only few established OEMs and a limited number of commercial pilot installations, and a very limited track record. At the same time, the basic physics behind these systems is very well understood and most of the required equipment is based on standard industrial systems (with modifications). This means that the risk is divided between technology as such (mostly the air storage systems) and the implementation of packaging of turbomachinery and control systems. A standardized set of technical parameters has not yet been developed by utilities; however, requirements associated to simple cycle and CCGT power plants can be used as a basis. Regulatory compliance requirements are still evolving but are expected to fall within existing categories of industrial structures, mining, and turbomachinery. Contractual technical support schemes such as Long-Term Service Agreements (LTSA) have not yet been developed.

Advantages of CAES include long lifespan, low lifetime costs, the ability to cost-effectively provide longer-duration energy storage (from days to weeks or months).

6.4.2 PERFORMANCE

CAES systems are well-suited for grid-tied systems designed for daily (especially longer- and very long-duration) cycling including load shifting (especially for renewable generating resources with long-term variability such as wind), long-term demand response, peak shaving, and some grid support applications. CAES systems have projected lifespan of over 60 years (the longest projected lifespan among new technologies in PNNL reports) before decommissioning or re-powering projects. They do not require capacity augmentation events during their lifetime on order to maintain nameplate performance and do not have a lifetime cycle limit. Their response time may be slower than Li-Ion batteries but similar to a simple cycle (for CAES) or CCGT (for A-CAES) power plant. A project-level analysis of critical performance requirements is recommended prior to considering this technology. Reference Appendix B for side-by-side comparison of the key technical parameters of CAES systems with other energy storage technologies included in this report.

6.5 COST ESTIMATES

Table 5 Energy Storage CAPEX Costs

Capacity	Lithium-Ion Battery	Flow Battery	Gravity Energy Storage	Compressed Air Energy Storage
200 MW	338.55	458.19	657.74	350.60
500 MW	827.38	1,026.46	1,515.07	876.50
1000 MW	1,612.33	2,128.06	1,889.84	1753.00

Note: All values in MM$ and exclude taxes/locational adjustment factor.

Table 6 Energy Storage Expected Lifetime Costs

Technology	Lithium-Ion Battery			Flow Battery			Gravity Energy Storage			Compressed Air Energy Storage		
Capacity (MW)	200	500	1000	200	500	1000	200	500	1000	200	500	1000
Lifetime Costs (MM$)	554.75	1355.75	2642.00	547.12	1186.79	2389.63	1092.27	2418.75	3281.92	743.18	1779.75	3404.47
Annual Lifetime Costs (MM$/yr.)	27.74	67.79	132.10	21.88	47.47	95.59	21.85	48.36	65.64	12.39	29.66	56.74

Table 6 shows the expected lifetime costs of the various energy storage technologies. These calculations consider CAPEX values (Table 5) along with O&M values for the expected life of each technology. Inflation of 2.5% per year is included. The design life for lithium-ion, flow, gravity energy storage, and compressed air energy storage are 20, 25, 50, and 60 years, respectively.

6.6 EMERGING ENERGY STORAGE TECHNOLOGIES

Due to a current low maturity level for grid-scale storage, high predicted costs and (for some technologies) low round-trip efficiency in their current form, the below technologies were not yet considered for the cost analysis section of this Report. The discussion below is provided for reference and a potential inclusion into future versions of the IRP. As a technology nearing technical maturity for grid-scale energy storage, the Iron-Air energy storage is included in Appendix B.

6.6.1 GENERAL DISCRIPTION

IRON-AIR

The technology is based on the interaction of iron with oxygen. The oxygen necessary for the reaction is taken from the ambient air, eliminating the requirement for the cell to store it. The high energetic densities with 1,200 Wh/kg produced by metal-air batteries are attributed to these component savings. Compared with the usual lithium-ion that has 600 Wh/kg, iron-oxygen batteries store more energy on the weight basis. Ferrous electrodes are also theoretically extremely durable, capable of withstanding over 10,000 full cycles. Iron-oxygen batteries are also resilient to overcharging, overcurrent, and partial discharge. A rechargeable iron-oxygen battery can supply 100 hours of energy at operating cost compared to traditional power stations and less than a tenth of the price of lithium-ion batteries. On the downside, the round-trip efficiency is quite low for the current offering (~38%), which limits this technology for applications addressing extremely high-power generation curtailment rates. There is currently one vendor offering commercial-scale systems.

NAS THERMAL

Sodium Sulfur batteries operate at elevated temperatures of 300-350C. The active materials in a NaS battery are molten sulfur as the positive electrode and molten sodium as the negative. The electrodes are separated by a solid ceramic, sodium alumina, which also serves as the electrolyte. This ceramic allows only positively charged sodium-ions to pass through. During discharge electrons are stripped off the sodium metal (one negatively charged electron for every sodium atom) leading to formation of the sodium-ions that then move through the electrolyte to the positive electrode compartment. The electrons that are stripped off the sodium metal move through the circuit and then back into the battery at the positive electrode, where they are taken up by the molten sulfur to form polysulfide. The positively charged sodium-ions moving into the positive electrode compartment balance the electron charge flow. During charge this process is reversed. The battery must be kept hot (typically > 300 ºC) to facilitate the process (i.e., independent heaters are part of the battery system). In general, NaS cells are highly efficient (typically 89%). There is currently one vendor offering NaS systems, with 190 systems installed in Japan and fifteen in UAE, with the combined capacity of 378MW/2,268MWh. The systems appear to be most suitable to 6+ hrs. duration storage.

ULTRACAPACITORS

Electrochemical capacitors (ECs) – sometimes referred to as "electric double-layer" capacitors, "Supercapacitor" or "Ultracapacitor" – provide a compelling set of characteristics – high energy density, extremely high cycle life, extremely fast response time. ECs have specific energy values that approach 206Wh/kg and up to 496W/kg power density. Because of their high power, long cycle life, good reliability, and other characteristics, the market and applications for ECs have been steadily increasing. There are dozens of manufacturers, and more are entering the market because of market growth. Aqueous electrolyte asymmetric EC technology offers opportunities to achieve exceptionally low-cost bulk energy storage. There are difference requirements for energy storage in different electricity grid-related applications from voltage support and load following to integration of wind generation and time-shifting. Symmetric ECs have response times on the order of 1 second and are well-suited for short duration high-power applications related to both grid regulation and frequency regulation. Asymmetric ECs are better suited for grid energy storage applications that have long duration, for instance, charge-at-night/use-during-the-day storage (i.e., bulk energy storage). Some asymmetric EC products have been optimized for ~5-hour charge with ~5-hour discharge. Advantages of ECs in these applications include long cycle life, good efficiency, low life-cycle costs, and adequate energy density.

7 CO-LOCATED PLANTS

7.1 GENERAL DESCRIPTION

WSP was tasked with analyzing three separate colocation scenarios, including Solar + Energy Storage, Wind + Energy Storage, and Wind + Solar + Energy Storage. All cost information (Capex and O&M) can be found in Appendix A. The colocation analysis was conducted by adding the separate scenarios, with a few tweaks, as discussed below.

7.2 SOLAR + ENERGY STORAGE

The solar plus energy storage models combine the 200 MW AC PV systems with a 200 MW Li-Ion battery by co-locating the projects together. It is assumed that the battery is AC coupled with the PV system. This layout requires a separate inverter for both the PV system and the battery, as was modeled in the separate PV and battery scenarios. There are benefits and constrains to the AC coupling method including cost and PV curtailment. WSP suggests that Owner conduct further analysis on DC and AC coupling to better understand what is needed for a given PV and energy storage scenario. One of the benefits of co-locating the two technologies together are cost reductions. NREL's "U.S. Solar Photovoltaic System and Energy Storage Cost Benchmarks: Q1 2021" states that co-located PV and Energy Storage plants see a 6-7% total cost reduction through cost savings resulting from site preparation; land acquisition; permitting and interconnection; installation; labor; hardware (via sharing of hardware such as switchgears, transformers, and controls); overhead; and profit.

The PV and energy storage spreadsheet was developed by combining the two separate scenarios into one. The only change aside from the 6% co-location cost reduction was the ability to use the DoE/EIA location adjustment factor for the Li-Ion battery now that there was a specific location tied to the energy storage system. This allowed for a more defined estimate of both capital and operational cost estimates for the battery. It should be noted that the addition of energy storage to a renewable energy plant can greatly increase the profit of the plant. Although the location plays a major factor, NREL's "Influence of Hybridization on the Capacity Value of PV and Battery Resources" discusses the economic benefit that could come from co-location. These intricacies were outside of the scope of this project but should be investigated by Owner to fully understand the economics of co-location.

7.3 WIND + ENERGY STORAGE

Similar to the PV and energy storage section above, there are assumed cost savings from pairing wind and energy storage. Although there is not a specific cost reduction factor published by a major national laboratory, WSP is confident that similar colocation savings would be present within a wind and energy storage combined power plant. Thus, the 6% cost reduction was also applied to these scenarios. Similar to Solar + Energy Storage, the battery costs were scaled by the DoE/EIA location adjustment factor given the location of the project.

7.4 WIND + SOLAR + ENERGY STORAGE

As stated above, there is an expected 6% colocation savings when energy storage is paired with a wind or solar plant. Additionally, NREL's "Potential Infrastructure Cost Savings at Hybrid Wind Plus Solar PV Plants" describes how the colocation of Wind + Solar can see cost savings of at least 7%. The report adds that, depending on the capacities of each, these savings can be much higher. Even though Owner could expect savings higher than 7% for a Wind + Solar + Energy Storage plant, the estimates provided contain a conservative margin of 7%.

8 CONCLUSION

This technology assessment is intended to provide PacifiCorp with greater insight into the associated costs of various renewable energy systems. The purpose of the document, and its accompanying spreadsheets, is to assist in the planning efforts regarding PacifiCorp's upcoming 2023 IRP. It should be noted again that this work has been done at a screening level and should be investigated further for any future project development.

Although recent inflation and tariffs have impeded the reduction in implementing renewable energy technologies, there is still a strong confidence that most, if not all, of the referenced technologies will continue to see cost declines over the next decade. Solar PV and onshore wind are proven to be cost-effective, and thus have lower associated risk. Offshore wind, although not heavily deployed in the United States, shows extreme potential—especially in PacifiCorp territory. This assessment investigated various energy storage technologies, each with different benefits and drawbacks. The ability to co-locate solar PV and wind with energy storage (and each other) can result in reduced EPC costs and incur even more cost savings throughout the project lifetime.

This assessment is intended to highlight high-level cost information, and not to provide a recommendation. Different technologies have various use cases, especially regarding a large utility that incorporates all kinds of grid services within their day-to-day work operations. The WSP Team has provided the conclusion of our research to assist with these specific operational decisions.

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APPENDIX

A - TECHNOLOGY COST ASSESSMENT

Appendix A

A - 1 Geothermal

PACIFICORP RENEWABLE TECHNOLOGY ASSESSMENT SUMMARY TABLE GEOTHERMAL		
PROJECT TYPE		
PROJECT LOCATION (Note 1)	**Dual Flash Expansion of Blundell Plant**	**Greenfield Binary Plant**
BASE PLANT DESCRIPTION	**200 MW**	**200 MW**
Reservoir Temperature (deg C)	245	245
Enthalpy (kJ/kg)	1,066	1,066
MW Generated per Blundell Well (MW/well)	7.7	6.7
# Production Wells Required	27	31
Total Flow (kg/s)	1,926	2,221
Drilling Failure Rate (%)	20%	20%
Production Wells Drilled	33	38
Reinjection Ratio (Production Flow/Reinjection Flow)	0.77	0.77
# Reinjection Wells Required	22	25
Reinjection Wells Drilled	27	30
Average Well Decline (%/yr)	3%	3%
Plant Capacity Factor (%)	95%	95%
ESTIMATED CAPITAL AND O&M COSTS		
EPC Costs, 2022 $MM	**$689**	**$1,000**
Drilling (Note 2)	$264.34	$304.3
Steam field Development	$105.69	$90.3
Power Plant	$310.26	$503.7
Interconnection	$8.24	$8.2
Owner's Costs Without Contingency, 2022 $MM	**$36**	**$47**
Engineering & PM	$26.62	$33.8
Legal Cost	$4.68	$6.8
Land Cost	$0.56	$0.6
Permitting	$0.19	$0.2
Geoscience & Environmental Assessments	$0.47	$0.5
Well Testing	$0.47	$0.5
Assessment Infrastructure	$2.58	$4.4
Feasibility Reports	$0.19	$0.2
Subtotal - Capital Cost, 2022 $MM	**$724**	**$1,047**
Owner's Contingency (5%)	$36.2	$52.4
State Taxes (Utah)	$47.2	$68.5
Total CAPEX, 2022 $MM	**$807.66**	**$1,167.99**
Total Screening Level Project Costs, 2022 $/kW	**$4,038**	**$5,840**
Demolition Costs (end of life cycle) 2022 $MM	**$23.40**	**$23.40**
O&M Cost, 2022 $MM/yr	**$23.0**	**$23.0**
O&M Cost, 2022 $/kW-yr	115.0	$115.0

Notes
Note 1: Greenfield Binary Plant location assumed in same geographic area as the Blundell Plant
Note 2: Assumed drilling depths 2500m for production wells & 2000m for reinjection wells

A - 2 PV Solar

PACIFICORP RENEWABLE TECHNOLOGY ASSESSMENT SUMMARY TABLE
SOLAR GENERATION

PROJECT TYPE						
PROJECT LOCATION	Idaho Falls, ID		Lakeview, OR		Milford, UT	
BASE PLANT DESCRIPTION	20 MW	200 MW	20 MW	200 MW	20 MW	200 MW
Nominal Output, MWac	20	200	20	200	20	200
Nominal Output, MWdc	26	260	26	260	26	260
Annualized Energy Production, MWh (Yr 1)	45,676	456,760	48,355	483,552	52,910	529,104
AC Capacity Factor at POI (%) (Note 1)	26.1%	26.1%	27.6%	27.6%	30.2%	30.2%
Availability Factor, % (Note 2)	99%	99%	99%	99%	99%	99%
Assumed Land Use, Acres (Note 2)	160	1600	160	1600	160	1600
PV Inverter Loading Ratio (DC/AC)	1.30	1.30	1.30	1.30	1.30	1.30
PV Degradation, %/yr (Note 2)	1st year: 2% After 1st Year: 0.5% per year	2nd year: 2% After 1st Year: 0.5% per year	1st year: 2% After 1st Year: 0.5% per year	2nd year: 2% After 1st Year: 0.5% per year	1st year: 2% After 1st Year: 0.5% per year	2nd year: 2% After 1st Year: 0.5% per year
Technology Rating	Mature	Mature	Mature	Mature	Mature	Mature
Permitting & Construction Schedule, year	2	2	2	2	2	2
ESTIMATED PERFORMANCE						
Base Load Performance @ (Annual Average) Net Plant Output, kW	20,000	200,000	20,000	200,000	20,000	200,000
ESTIMATED CAPITAL AND O&M COSTS						
EPC Project Capital Costs, 2022 MM$ (w/o Owner's Costs)	**$17.1**	**$140.8**	**$17.1**	**$140.8**	**$17.1**	**$140.8**
Modules	$6.7	$66.8	$6.7	$66.8	$6.7	$66.8
Inverter	$1.0	$8.0	$1.0	$8.0	$1.0	$8.0
Structural BOS	$2.4	$20.0	$2.4	$20.0	$2.4	$20.0
Electrical BOS	$2.4	$10.0	$2.4	$10.0	$2.4	$10.0
Installer OH (Labor Costs)	$2.2	$20.0	$2.2	$20.0	$2.2	$20.0
EPC OH (Equipment and Material)	$1.6	$10.0	$1.6	$10.0	$1.6	$10.0
EPC Markup	$0.8	$6.0	$0.8	$6.0	$0.8	$6.0
Owner's Costs, 2022 MM$	**$3.0**	**$24.0**	**$3.0**	**$24.0**	**$3.0**	**$24.0**
Engineering & Development OH	$1.0	$4.0	$1.0	$4.0	$1.0	$4.0
Transmission Line	$0.20	$2.0	$0.20	$2.0	$0.20	$2.0
PII (permitting fee, interconnection, commissioning)	$0.8	$8.0	$0.8	$8.0	$0.8	$8.0
Land Acquisition (Note 3)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Owner's Project Development	$1.0	$10.0	$1.0	$10.0	$1.0	$10.0
Owner's Project Management	PAC to input values	PAC to input values	PAC to input values	PAC to input values	PAC to input values	PAC to input values
Owner's Legal Costs	PAC to input values	PAC to input values	PAC to input values	PAC to input values	PAC to input values	PAC to input values
Contingency and Insurance, 2022 MM$	**$0.7**	**$5.5**	**$0.7**	**$5.5**	**$0.7**	**$5.5**
Owner's Contingency (3%) (Note 4)	$0.6	$4.9	$0.6	$4.9	$0.6	$4.9
Builders Risk Insurance (.317%) (Note 4)	$0.1	$0.5	$0.1	$0.5	$0.1	$0.5
Total Screening Level Project Costs, 2022 MM$	**$20.7**	**$170.3**	**$20.7**	**$170.3**	**$20.7**	**$170.3**
State Taxes (Note 4)	**$1.0**	**$8.4**	**$0.0**	**$0.0**	**$1.2**	**$9.5**
Balance of Plant Materials and Products	$0.89	$7.25	0	$0.0	$1.02	$8.27
Labor and Services	$0.13	$1.20	0	$0.0	$0.1	$1.2
CAPEX, 2022 MM$	**$21.77**	**$178.71**	**$20.75**	**$170.27**	**$21.90**	**$179.74**
Location Adjusted CAPEX 2022 MM$	**$21.34**	**$175.14**	**$21.78**	**$178.78**	**$21.24**	**$174.35**
Total Screening Level Project Costs, 2022 $/kWdc	**$1,066.77**	**$875.70**	**$1,089.17**	**$893.90**	**$1,086.18**	**$825.79**
Total Screening Level Project Costs, 2022 $/kWac	**$1,386.80**	**$1,138.41**	**$1,415.92**	**$1,162.07**	**$1,308.04**	**$1,073.53**
Demolition Costs (end of life cycle) 2022 MM$ (Note 5)	**$0.59**	**$5.88**	**$0.63**	**$6.30**	**$0.58**	**$5.82**
O&M Cost, 2023 MM$/yr (Note 6)	**$0.4**	**$4.2**	**$0.4**	**$4.2**	**$0.4**	**$4.2**
Module cleaning	$0.043	$0.433	$0.043	$0.433	$0.043	$0.433
Vegetation and/or Pest Management	$0.016	$0.158	$0.016	$0.158	$0.016	$0.158
System inspection and monitoring	$0.045	$0.449	$0.045	$0.449	$0.045	$0.449
Component parts replacement	$0.033	$0.327	$0.033	$0.327	$0.033	$0.327
Module replacement	$0.007	$0.075	$0.007	$0.075	$0.007	$0.075
Inverter replacement	$0.078	$0.779	$0.078	$0.779	$0.078	$0.779
Land Lease	$0.055	$0.547	$0.055	$0.547	$0.055	$0.547
Property tax	$0.043	$0.433	$0.043	$0.433	$0.043	$0.433
Insurance	$0.051	$0.507	$0.051	$0.507	$0.051	$0.507
Asset management and security (Note 6)	$0.041	$0.410	$0.041	$0.410	$0.041	$0.410
Operations administration	$0.006	$0.057	$0.006	$0.057	$0.006	$0.057
O&M Cost, 2023 $/kWac-yr	**$20.87**	**$20.87**	**$20.87**	**$20.87**	**$20.87**	**$20.87**

Notes

Note 1. Solar capacity factor supplied by PAC.
Note 2. Base plant descriptions provided by PAC.
Note 3. Land is assumed to be leased throughout the project lifetime and is thus included in yearly O&M values.
Note 4. State Tax rates provided by PAC.
Note 5. Demolition costs are seen as an optional end-of-life cost, as other options like repowering the plant are available.
Note 6. Third party long-term service agreement costs are included in the asset management and security line item.

Appendix A

A - 3 PV Solar (Cont.)

PACIFICORP RENEWABLE TECHNOLOGY ASSESSMENT SUMMARY TAB SOLAR GENERATION				
PROJECT TYPE				
PROJECT LOCATION	**Rock Springs, WY**		**Yakima, WA**	
BASE PLANT DESCRIPTION	**20 MW**	**200 MW**	**20 MW**	**200 MW**
Nominal Output, MWac	20	200	20	200
Nominal Output, MWdc	26	260	26	260
Annualized Energy Production, MWh (Yr 1)	48,944	489,439	42,369	423,694
AC Capacity Factor at POI (%) (Note 1)	27.9%	27.9%	24.2%	24.2%
Availability Factor, % (Note 2)	99%	99%	99%	99%
Assumed Land Use, Acres (Note 2)	160	1600	160	1600
PV Inverter Loading Ratio (DC/AC)	1.30	1.30	1.30	1.30
PV Degradation, %/yr (Note 2)	1st year: 2% After 1st Year: 0.5% per year	2nd year: 2% After 1st Year: 0.5% per year	1st year: 2% After 1st Year: 0.5% per year	2nd year: 2% After 1st Year: 0.5% per year
Technology Rating	Mature	Mature	Mature	Mature
Permitting & Construction Schedule, year	2	2	2	2
ESTIMATED PERFORMANCE				
Base Load Performance @ (Annual Average)				
Net Plant Output, kW	20,000	200,000	20,000	200,000
ESTIMATED CAPITAL AND O&M COSTS				
EPC Project Capital Costs, 2022 MM$ (w/o Owner's Costs)	**$17.1**	**$140.8**	**$17.1**	**$140.8**
Modules	$6.7	$66.8	$6.7	$66.8
Inverter	$1.0	$8.0	$1.0	$8.0
Structural BOS	$2.4	$20.0	$2.4	$20.0
Electrical BOS	$2.4	$10.0	$2.4	$10.0
Installer OH (Labor Costs)	$2.2	$20.0	$2.2	$20.0
EPC OH (Equipment and Material)	$1.6	$10.0	$1.6	$10.0
EPC Markup	$0.8	$6.0	$0.8	$6.0
Owner's Costs, 2022 MM$	**$3.0**	**$24.0**	**$3.0**	**$24.0**
Engineering & Development OH	$1.0	$4.0	$1.0	$4.0
Transmission Line	$0.20	$2.0	$0.20	$2.0
PII (permitting fee, interconnection, commissioning)	$0.8	$8.0	$0.8	$8.0
Land Acquisition (Note 3)	$0.0	$0.0	$0.0	$0.0
Owner's Project Development	$1.0	$10.0	$1.0	$10.0
Owner's Project Management	PAC to input values	PAC to input values	PAC to input values	PAC to input values
Owner's Legal Costs	PAC to input values	PAC to input values	PAC to input values	PAC to input values
Contingency and Insurance, 2022 MM$	**$0.7**	**$5.5**	**$0.7**	**$5.5**
Owner's Contingency (3%) (Note 4)	$0.6	$4.9	$0.6	$4.9
Builders Risk Insurance (.317%) (Note 4)	$0.1	$0.5	$0.1	$0.5
Total Screening Level Project Costs, 2022 MM$	**$20.7**	**$170.3**	**$20.7**	**$170.3**
State Taxes (Note 4)	**$0.8**	**$6.4**	**$1.5**	**$12.3**
Balance of Plant Materials and Products	$0.79	$6.44	$1.30	$10.57
Labor and Services	0	0	$0.19	$1.75
CAPEX, 2022 MM$	**$21.54**	**$176.71**	**$22.24**	**$182.59**
Location Adjusted CAPEX 2022 MM$	**$21.75**	**$178.47**	**$22.91**	**$188.07**
Total Screening Level Project Costs, 2022 $/kWdc	**$1,047.68**	**$859.85**	**$1,068.42**	**$876.87**
Total Screening Level Project Costs, 2022 $/kWac	**$1,361.98**	**$1,117.80**	**$1,388.95**	**$1,139.93**
Demolition Costs (end of life cycle) 2022 MM$ (Note 5)	**$0.61**	**$6.06**	**$0.62**	**$6.18**
O&M Cost, 2020 MM$/yr (Note 6)	**$0.4**	**$4.2**	**$0.4**	**$4.2**
Module cleaning	$0.043	$0.433	$0.043	$0.433
Vegetation and/or Pest Management	$0.016	$0.158	$0.016	$0.158
System inspection and monitoring	$0.045	$0.449	$0.045	$0.449
Component parts replacement	$0.033	$0.327	$0.033	$0.327
Module replacement	$0.007	$0.075	$0.007	$0.075
Inverter replacement	$0.078	$0.779	$0.078	$0.779
Land Lease	$0.055	$0.547	$0.055	$0.547
Property tax	$0.043	$0.433	$0.043	$0.433
Insurance	$0.051	$0.507	$0.051	$0.507
Asset management and security (Note 6)	$0.041	$0.410	$0.041	$0.410
Operations administration	$0.006	$0.057	$0.006	$0.057
O&M Cost, 2020 $/kWac-yr	**$20.87**	**$20.87**	**$20.87**	**$20.87**

Notes

Note 1. Solar capacity factor supplied by PAC.
Note 2. Base plant descriptions provided by PAC.
Note 3. Land is assumed to be leased throughout the project lifetime and is thus included in yearly O&M values.
Note 4. State Tax rates provided by PAC.
Note 5. Demolition costs are seen as an optional end-of-life cost, as other options like repowering the plant are available.
Note 6. Third party long-term service agreement costs are included in the asset management and security line item.

A - 4 ONSHORE WIND

PACIFICORP RENEWABLE TECHNOLOGY ASSESSMENT SUMMARY TABLE
WIND GENERATION

PROJECT TYPE	Onshore Wind									
PROJECT LOCATION	Pocatello, ID		Arlington, OR		Monticello, UT		Medicine Bow, WY		Goldendale, WA	
BASE PLANT DESCRIPTION	20 MW	200 MW	20 MW	200 MW	20 MW	200 MW	20 MW	200 MW	20 MW	200 MW
ESTIMATED CAPITAL AND O&M COSTS										
BOP Project Capital Costs, 2022 $MM (w/o Owner's Costs)	**$34.79**	**$263.1**	**$34.79**	**$263.1**	**$34.79**	**$263.1**	**$34.79**	**$263.1**	**$34.79**	**$263.1**
Wind Turbine Generators	$17.50	$175.00	$17.50	$175.00	$17.50	$175.00	$17.50	$175.00	$17.50	$175.00
Met Mast	$1.05	$1.05	$1.05	$1.05	$1.05	$1.05	$1.05	$1.05	$1.05	$1.05
Foundations	$1.42	$14.19	$1.42	$14.19	$1.42	$14.19	$1.42	$14.19	$1.42	$14.19
Assembly & Installation	$0.86	$8.57	$0.86	$8.57	$0.86	$8.57	$0.86	$8.57	$0.86	$8.57
Roads & Crane Pads	$0.95	$9.49	$0.95	$9.49	$0.95	$9.49	$0.95	$9.49	$0.95	$9.49
O&M Building	$1.1	$1.1	$1.1	$1.1	$1.1	$1.1	$1.1	$1.1	$1.1	$1.1
Collection System	$1.2	$12.2	$1.2	$12.2	$1.2	$12.2	$1.2	$12.2	$1.2	$12.2
SCADA	$0.2	$0.4	$0.2	$0.4	$0.2	$0.4	$0.2	$0.4	$0.2	$0.4
Switchgear/Substation (Note 2 & 3)	$5.1	$15.9	$5.1	$15.9	$5.1	$15.9	$5.1	$15.9	$5.1	$15.9
Step-Up Transformer & Interconnection (Note 4)	$1.97	$4.92	$1.97	$4.92	$1.97	$4.92	$1.97	$4.92	$1.97	$4.92
Aircraft Detection Lighting System	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
EPC Fee (8%)	$2.58	$19.49	$2.58	$19.49	$2.58	$19.49	$2.58	$19.49	$2.58	$19.49
Owner's Costs Without Contingency, 2022 $MM	**$1.2**	**$5.5**	**$1.8**	**$6.2**	**$1.2**	**$5.5**	**$1.5**	**$5.9**	**$1.9**	**$6.4**
Project Design	$0.2	$2.0	$0.2	$2.0	$0.2	$2.0	$0.2	$2.0	$0.2	$2.0
Owner's Engineer	$0.05	$0.17	$0.05	$0.17	$0.05	$0.17	$0.05	$0.17	$0.05	$0.17
Land Lease & Development	$0.2	$2.4	$0.2	$2.4	$0.2	$2.4	$0.2	$2.4	$0.2	$2.4
Permitting (Note 5)	$0.5	$0.6	$1.1	$1.4	$0.5	$0.6	$0.9	$1.1	$1.3	$1.6
Wildlife Studies	$0.1	$0.2	$0.1	$0.2	$0.1	$0.2	$0.1	$0.2	$0.1	$0.2
Eagle Take Permits	$0.07	$0.09	$0.07	$0.09	$0.07	$0.09	$0.07	$0.09	$0.07	$0.09
Capital Spares	Included in O&M	Included in O&M	Included in O&M	Included in O&M	Included in O&M	Included in O&M	Included in O&M	Included in O&M	Included in O&M	Included in O&M
Subtotal - Capital Costs, 2022 $MM	**$36.0**	**$268.5**	**$36.5**	**$269.3**	**$36.0**	**$268.6**	**$36.3**	**$269.0**	**$36.7**	**$269.5**
Owner's Contingency (5% of Capital Cost)	$1.8	$13.4	$1.8	$13.5	$1.8	$13.4	$1.8	$13.5	$1.8	$13.5
Total - Costs With Contingency, 2022 $MM	**$37.8**	**$282.0**	**$38.4**	**$282.8**	**$37.8**	**$282.0**	**$38.1**	**$282.5**	**$38.5**	**$283.0**
State Taxes, $MM (Note 6)	**$2.0**	**$14.7**	**$0.0**	**$0.0**	**$1.7**	**$14.3**	**$1.8**	**$14.7**	**$2.9**	**$21.5**
Balance of Plant Materials and Products	$1.5	$12.5	NA	NA	$1.7	$14.3	$1.3	$12.5	$2.1	$18.3
Labor and Services	$0.5	$2.2	NA	NA	NA	NA	$0.5	$2.2	$0.8	$3.2
CAPEX, 2022 $MM	**$39.73**	**$296.73**	**$38.37**	**$282.79**	**$39.42**	**$296.32**	**$39.93**	**$297.19**	**$41.42**	**$304.46**
Location Adjusted CAPEX 2022 $MM	**$40.13**	**$299.70**	**$39.91**	**$294.10**	**$40.60**	**$305.21**	**$39.53**	**$294.21**	**$42.25**	**$310.55**
Total Screening Level Project Costs, 2022 $/kW	**$2,006.56**	**$1,498.51**	**$1,995.44**	**$1,470.50**	**$2,030.00**	**$1,526.07**	**$1,976.66**	**$1,471.07**	**$2,112.46**	**$1,552.76**
Demolition Costs (end of life cycle) 2022 $MM (Note 6)	**$1.19**	**$11.89**	**$1.19**	**$11.89**	**$1.19**	**$11.89**	**$1.19**	**$11.89**	**$1.19**	**$11.89**
O&M Cost, 2022 $MM/yr	**$0.9**	**$8.6**	**$0.9**	**$8.6**	**$0.9**	**$8.6**	**$0.9**	**$8.6**	**$0.9**	**$8.6**
O&M Cost, 2022 $/kW-yr	$43.0	$43.0	$43.0	$43.0	$43.0	$43.0	$43.0	$43.0	$43.0	$43.0

Notes

Note 1. 20 MW Substation assumes: Tie in 230kV line through three disconnects, a single 230kV breaker connection, & a 1200A, 34.5kV GIS switchgear housed in a building

Note 2. 200 MW Substation assumes: Three breaker ring 230kV AIS switchgear & (2) 2500A, 34.5kV GIS switchgear housed in a building

Note 3. 20 MW Plant assumes (1) 30 MVA (230 kV/34.5 kV) transformer & 200 MW Plant assumes (2) 125 MVA (230 kV/34.5 kV) transformer. 1 one mile interconnection tie line is assumed for both cases.

Note 4. Permitting cost assumes the permitting matrix from the 2022 PacifiCorp All-Source RFP is utilized

Note 5. State Tax information provided by PacifiCorp

Note 6. Reclamation costs included in Demolition costs. Demolition costs are seen as an optional end-of-life cost, as other options like repowering the plant are available.

A - 5 OFFSHORE WIND

PACIFICORP RENEWABLE TECHNOLOGY ASSESSMENT SUMMARY TABLE WIND GENERATION		
PROJECT TYPE	**Offshore Wind**	
PROJECT LOCATION	**Northern, CA**	
BASE PLANT DESCRIPTION	**200 MW**	**1,000 MW**
ESTIMATED CAPITAL AND O&M COSTS (Note 1)		
BOP Project Capital Costs, 2022 $MM (w/o Owner's Costs)	**$673.7**	**$3,368.4**
Wind Turbine Generators	$224.84	1124.22
Substructure	$213.93	1069.66
Port, Staging, Logistics, & Fixed Costs	$7.62	38.11
Turbine Install	$25.46	127.32
Substructure Install	$13.34	66.69
Array Cabling	$47.6	238.18
Export Cable	$77.4	387.16
Onshore Spur Line	$13.5	67.56
EPC Fee (8%)	$49.90	249.51
Owner's Costs Without Contingency, 2022 $MM	**$67.4**	**$336.9**
Development	$24.1	120.39
Lease Price	$15.24	76.22
Project Management	$12.5	62.36
Insurance during Construction	$7.8	38.98
Project Completion	$7.8	38.98
Subtotal - Capital Costs, 2022 $MM	**$741.1**	**$3,705.3**
Procurement Contingency	$36.6	182.75
Installation Contingency	$13.5	67.56
Total - Owner's Costs With Contingency, 2022 $MM	**$791.1**	**$3,955.6**
CAPEX, 2022 $MM	**$791.13**	**$3,955.63**
Total Screening Level Project Costs, 2022 $/kW	**$3,955.63**	**$3,955.63**
Demolition Costs (end of life cycle) 2022 $MM	**$31.65**	**$158.23**
O&M Cost, 2022 $MM/yr	**$20.6**	**$103.0**
O&M Cost, 2022 $/kW-yr	$103.0	$103.0
Notes Note 1. Capital Costs are over-night & don't include financing costs		

A - 6

PACIFICORP RENEWABLE TECHNOLOGY ASSESSMENT SUMMARY TABLE WIND GENERATION		
PROJECT TYPE	Offshore Wind	
PROJECT LOCATION	Northern, CA	
BASE PLANT DESCRIPTION	200 MW	1,000 MW
ESTIMATED CAPITAL AND O&M COSTS (Note 1)		
BOP Project Capital Costs, 2022 $MM (w/o Owner's Costs)	**$673.7**	**$3,368.4**
Wind Turbine Generators	$224.84	1124.22
Substructure	$213.93	1069.66
Port, Staging, Logistics, & Fixed Costs	$7.62	38.11
Turbine Install	$25.46	127.32
Substructure Install	$13.34	66.69
Array Cabling	$47.6	238.18
Export Cable	$77.4	387.16
Onshore Spur Line	$13.5	67.56
EPC Fee (8%)	$49.90	249.51
Owner's Costs Without Contingency, 2022 $MM	**$67.4**	**$336.9**
Development	$24.1	120.39
Lease Price	$15.24	76.22
Project Management	$12.5	62.36
Insurance during Construction	$7.8	38.98
Project Completion	$7.8	38.98
Subtotal - Capital Costs, 2022 $MM	**$741.1**	**$3,705.3**
Procurement Contingency	$36.6	182.75
Installation Contingency	$13.5	67.56
Total - Owner's Costs With Contingency, 2022 $MM	**$791.1**	**$3,955.6**
CAPEX, 2022 $MM	**$791.13**	**$3,955.63**
Total Screening Level Project Costs, 2022 $/kW	**$3,955.63**	**$3,955.63**
Demolition Costs (end of life cycle) 2022 $MM	**$31.65**	**$158.23**
O&M Cost, 2022 $MM/yr	**$20.6**	**$103.0**
O&M Cost, 2022 $/kW-yr	$103.0	$103.0
Notes Note 1. Capital Costs are over-night & don't include financing costs		

A - 7 Energy Storage: Li-Ion

PACIFICORP RENEWABLE TECHNOLOGY ASSESSMENT SUMMARY TABLE BESS GENERATION			
TECHNOLOGY	**Lithium-ion batteries (Li-Ion)**		
BASE PLANT DESCRIPTION, MW	**200**	**500**	**1000**
Net Plant Output kW	200,000	500,000	1,000,000
Capacity, hours	4	4	4
Design Life (Assuming 365 Cycles per Year)	20	20	20
Round Trip Efficiency (AC-AC)	83%	83%	83%
Estimated Annual Throughput (MWh) (80% Max Discharge)	59,096	147,740	295,480
kWh	800,000	2,000,000	4,000,000
ESTIMATED CAPITAL AND O&M COSTS (Note 7)			
Storage Block (Note 1)	$132.00	$321.62	$630.64
Storage BOS (Note 2)	$30.40	$74.76	$146.60
Power Equipment (Note 3)	$12.60	$28.56	$54.40
Controls & Communication (Note 4)	$0.30	$0.58	$1.12
System Integration (Note 5)	$34.40	$85.56	$167.80
Engineering, Procurement & Construction (Note 6)	$41.60	$101.82	$199.68
Project Development (Note 7)	$50.40	$125.78	$239.60
Grid Integration (Note 8)	$3.98	$8.36	$15.94
EPC Markup (5%)	$15.28	$37.35	$72.79
EPC Project Capital Costs, 2022 $MM (w/o Owner's Costs)	**$320.96**	**$784.39**	**$1,528.57**
Land Acquisition	Leased	Leased	Leased
Owner's Project Development	PAC Provided	PAC Provided	PAC Provided
Owner's Project Management	PAC Provided	PAC Provided	PAC Provided
Owner's Legal Costs	PAC Provided	PAC Provided	PAC Provided
Owner's Costs, 2022 $MM	**$0.00**	**$0.00**	**$0.00**
Owner's Contingency (5%)	$16.0481	$39.2196	$76.4285
Builders Risk Insurance (0.48%)	$1.5406	$3.7651	$7.3371
Total Owners Costs With Contingency, 2022 $MM	**$17.589**	**$42.985**	**$83.766**
CAPEX, 2022 $MM	**$338.55**	**$827.38**	**$1,612.33**
Total Screening Level Project Costs, 2022 $/kWh	**$423.19**	**$413.69**	**$403.08**
CAPEX, 2022 $/kW	**$1,692.75**	**$1,654.75**	**$1,612.33**
Demolition Costs (end of life cycle) 2022$/kW (Note 9)	**$24**	**$24**	**$24**
O&M Cost, 2020 MM$/yr	**$8.46**	**$20.68**	**$40.31**
Fixed O&M (Note 10)	$8.46	$20.68	$40.31
Variable O&M	Included	Included	Included
Warranty	Included	Included	Included
O&M Cost, 2020 $/kWdc-yr	**$42.32**	**$41.37**	**$40.31**
Inflation Rate (%) (Note 11)	2.50%	2.50%	2.50%
Lifetime Cost (MM$)	**554.75**	**1335.75**	**2642.00**
Annual Lifetime Cost (MM$/year)	**27.74**	**69.79**	**132.10**

A - 8 Energy Storage: Flow

PACIFICORP RENEWABLE TECHNOLOGY ASSESSMENT SUMMARY TABLE BESS GENERATION			
TECHNOLOGY		**Flow Batteries**	
BASE PLANT DESCRIPTION, MW	**200**	**500**	**1000**
Net Plant Output,kW	200,000	500,000	1,000,000
Capacity, hours	4	4	4
Design Life (Assuming 365 Cycles per Year)	25	25	25
Round Trip Efficiency (AC-AC)	70%	70%	70%
Estimated Annual Throughput (MWh) (80% Max Discharge)	49,840	124,600	249,200
kWh	800,000	2,000,000	4,000,000
ESTIMATED CAPITAL AND O&M COSTS (Note 7)			
Storage Block (Note 1)	$208.80	$484.96	$950.92
Storage BOS (Note 2)	$41.60	$99.84	$190.20
Power Equipment (Note 3)	$23.00	$54.92	$107.69
Controls & Communication (Note 4)	$0.30	$0.76	$1.50
System Integration (Note 5)	$38.40	$38.23	$187.44
Engineering, Procurement, & Construction (Note 6)	$43.20	$107.88	$215.68
Project Development (Note 7)	$54.40	$130.20	$248.00
Grid Integration (Note 8)	$4.00	$10.00	$20.00
EPC Markup (5%)	$20.69	$46.34	$96.07
EPC Project Capital Costs, 2022 $MM (w/o Owner's Costs)	**$434.39**	**$973.13**	**$2,017.50**
Land Acquisition	Leased	Leased	Leased
Owner's Project Development	PAC Provided	PAC Provided	PAC Provided
Owner's Project Management	PAC Provided	PAC Provided	PAC Provided
Owner's Legal Costs	PAC Provided	PAC Provided	PAC Provided
Owner's Costs, 2022 $MM	**$0.00**	**$0.00**	**$0.00**
Owner's Contingency (5%)	$21.7193	$48.6566	$100.8751
Builders Risk Insurance (0.48%)	$2.0850	$4.6710	$9.6840
Total Owners Costs With Contingency, 2022 $MM	**$23.804**	**$53.328**	**$110.559**
CAPEX, 2022 $MM	**$458.19**	**$1,026.46**	**$2,128.06**
Total Screening Level Project Costs, 2022 $/kWh	**$572.74**	**$513.23**	**$532.02**
CAPEX, 2022 $/kW	**$2,290.95**	**$2,052.92**	**$2,128.06**
Demolition Costs (end of life cycle) 2022$/kW (Note 9)	**$34**	**$33**	**$32**
O&M Cost, 2020 MM$/yr	**$12.88**	**$27.42**	**$54.99**
Fixed O&M (Note 10)	$11.45	$25.66	$53.20
Variable O&M	$0.03	$0.06	$0.13
Warranty	$1.40	$1.69	$1.66
O&M Cost, 2020 $/kWdc-yr	**$64.40**	**$54.83**	**$54.99**
Inflation Rate (%) (Note 11)	2.50%	2.50%	2.50%
Lifetime Cost (MM$)	**547.12**	**1186.79**	**2389.63**
Annual Lifetime Cost (MM$/year)	**21.88**	**47.47**	**95.59**

A - 9 Energy Storage: Gravity

PACIFICORP RENEWABLE TECHNOLOGY ASSESSMENT SUMMARY TABLE BESS GENERATION			
TECHNOLOGY	Gravity Batteries		
BASE PLANT DESCRIPTION, MW	200	500	1000
Net Plant Output,kW	200,000	500,000	1,000,000
Capacity, hours	4	4	4
Design Life (Assuming 365 Cycles per Year)	50	50	50
Round Trip Efficiency (AC-AC)	83%	83%	83%
Estimated Annual Throughput (MWh) (80% Max Discharge)	59,096	147,740	295,480
kWh	800,000	2,000,000	4,000,000
ESTIMATED CAPITAL AND O&M COSTS (Note 7)			
Storage Block (Note 1)	$305.30	$680.98	$788.00
Storage BOS (Note 2)			
Power Equipment (Note 3)	$182.07	$455.18	$630.34
Controls & Communication (Note 4)	$0.00	$0.00	$0.00
System Integration (Note 5)	$0.00	$0.00	$0.00
Engineering, Procurement, & Construction (Note 6)			
Project Development (Note 7)	$97.47	$231.80	$288.00
Grid Integration (Note 8)			
EPC Markup (5%)	$29.24	$68.40	$85.32
EPC Project Capital Costs, 2022 $MM (w/o Owner's Costs)	**$614.09**	**$1,436.36**	**$1,791.66**
Land Acquisition	Leased	Leased	Leased
Owner's Project Development	PAC Provided	PAC Provided	PAC Provided
Owner's Project Management	PAC Provided	PAC Provided	PAC Provided
Owner's Legal Costs	PAC Provided	PAC Provided	PAC Provided
Owner's Costs, 2022 $MM	**$0.00**	**$0.00**	**$0.00**
Owner's Contingency (5%)	$30.7043	$71.8179	$89.5829
Builders Risk Insurance (0.48%)	$2.9476	$6.8945	$8.6000
Total Owners Costs With Contingency, 2022 $MM	**$33.652**	**$78.712**	**$98.183**
CAPEX, 2022 $MM	**$647.74**	**$1,515.07**	**$1,889.84**
Total Screening Level Project Costs, 2022 $/kWh	**$809.67**	**$757.54**	**$472.46**
CAPEX, 2022 $/kW	**$3,238.69**	**$3,030.14**	**$1,889.84**
Demolition Costs (end of life cycle) 2022$/kW (Note 9)	**$0.30**	**$0.24**	**$0.18**
O&M Cost, 2020 MM$/yr	**$16.19**	**$37.88**	**$47.25**
Fixed O&M (Note 10)	$16.19	$37.88	$47.25
Variable O&M	Included	Included	Included
Warranty	Included	Included	Included
O&M Cost, 2020 $/kWdc-yr	**$80.97**	**$75.75**	**$47.25**
Inflation Rate (%) (Note 11)	2.50%	2.50%	2.50%
Lifetime Cost (MM$)	**1092.27**	**2418.75**	**3281.92**
Annual Lifetime Cost (MM$/year)	**21.85**	**48.38**	**65.64**

A - 10 Energy Storage: Notes

Notes
Note 1. Storage Block includes the price for the most basic direct current (DC) storage element in an ESS (e.g., for lithium-ion, this price includes the battery module, rack, and battery management system, and is comparable to an electric vehicle (EV) pack price).
Note 2. Balance of System includes supporting cost components for the SB with container, cabling, switchgear, flow battery pumps, and heating, ventilation, and air conditioning (HVAC).
Note 3. Power Equipment includes bidirectional invertor, DC-DC converter, isolation protection, alternating current (AC) breakers, relays, communication interface, and software.
Note 4. Controls & Communication includes the energy management system for the entire ESS and is responsible for ESS operation. This may also include annual licensing costs for software. The cost is typically represented as a fixed cost scalable with respect to power and independent of duration.
Note 5. System Integration is the price charged by the system integrator to integrate subcomponents of a BESS into a single functional system. Tasks include procurement and shipment to the site of battery modules, racks with cables in place, containers, and power equipment. At the site, the modules and racks are containerized with HVAC and fire suppression installed and integrated with the power equipment to provide a turnkey system.
Note 6. EPC includes non-recurring engineering costs and construction equipment as well as shipping, siting and installation, and commissioning of the ESS. This cost is weighted based on E/P ratio.
Note 7. Project Development costs associated with permitting, power purchase agreements, interconnection agreements, site control, and financing.
Note 8. Grid Integration direct cost associated with connecting the ESS to the grid, including transformer cost, metering, and isolation breakers. For the last component, it could be a single disconnect breaker or a breaker bay for larger systems.
Note 9. Demo Costs include disconnection, disassembly/removal, site remediation, and recycle/disposal. Gravity Storage Demolition costs are for crane/building-based systems (i.e. Energy Vault).
Note 10. Fixed O&M prices for Lithium-Ion batteries includes estimated augmentation costs for the lifetime of the battery. Variable O&M is included in the fixed O&M for Li-Ion.
Note 11. Average inflation rates over the past decades have averaged 2.5% (US Federal Reserve)

A - 11 Solar + Energy Storage

PACIFICORP RENEWABLE TECHNOLOGY ASSESSMENT SUMMARY TABLE SOLAR + ENERGY STORAGE GENERATION					
PROJECT TYPE	SOLAR + ENERGY STORAGE				
PROJECT LOCATION	Idaho Falls, ID	Lakeview, OR	Milford, UT	Rock Springs, WY	Yakima, WA
BASE PLANT DESCRIPTION	200 MW	200 MW	200 MW	200 MW	200 MW
Nominal Output, MWac	200	200	200	200	200
Nominal Output, MWdc	260	260	260	260	280
Annualized Energy Production, MWh (Yr 1)	456,760	483,552	529,104	489,439	423,694
AC Capacity Factor at POI (%) (Note 1)	26.1%	27.6%	30.2%	27.9%	24.2%
Availability Factor, % (Note 2)	99%	99%	99%	99%	99%
Assumed Land Use, Acres (Note 2)	1600	1600	1600	1600	1600
PV Inverter Loading Ratio (DC/AC)	1.30	1.30	1.30	1.30	1.30
PV Degradation, %/yr (Note 2)	2nd year: 2% After 1st Year: 0.5% per year	2nd year: 2% After 1st Year: 0.5% per year	2nd year: 2% After 1st Year: 0.5% per year	2nd year: 2% After 1st Year: 0.5% per year	2nd year: 2% After 1st Year: 0.5% per year
Technology Rating	Mature	Mature	Mature	Mature	Mature
Permitting & Construction Schedule, year	2	2	2	2	2
ESTIMATED PERFORMANCE					
Base Load Performance @ (Annual Average)					
Net Plant Output, kW	200,000	200,000	200,000	200,000	200,000
ESTIMATED CAPITAL AND O&M COSTS					
EPC Project Capital Costs, 2022 MM$ (w/o Owner's Costs)	**$140.8**	**$140.8**	**$140.8**	**$140.8**	**$140.8**
Modules	$66.8	$66.8	$66.8	$66.8	$66.8
Inverter	$8.0	$8.0	$8.0	$8.0	$8.0
Structural BOS	$20.0	$20.0	$20.0	$20.0	$20.0
Electrical BOS	$10.0	$10.0	$10.0	$10.0	$10.0
Installer OH (Labor Costs)	$20.0	$20.0	$20.0	$20.0	$20.0
EPC OH (Equipment and Material)	$10.0	$10.0	$10.0	$10.0	$10.0
EPC Markup	$6.0	$6.0	$6.0	$6.0	$6.0
Owner's Costs, 2022 MM$	**$24.0**	**$24.0**	**$24.0**	**$24.0**	**$24.0**
Engineering & Development OH	$4.0	$4.0	$4.0	$4.0	$4.0
Transmission Line	$2.0	$2.0	$2.0	$2.0	$2.0
PII (permitting fee, interconnection, commissioning)	$8.0	$8.0	$8.0	$8.0	$8.0
Land Acquisition (Note 3)	$0.0	$0.0	$0.0	$0.0	$0.0
Owner's Project Development	$10.0	$10.0	$10.0	$10.0	$10.0
Owner's Project Management	PAC to input values	PAC to input values	PAC to input values	PAC to input values	PAC to input values
Owner's Legal Costs	PAC to input values	PAC to input values	PAC to input values	PAC to input values	PAC to input values
Contingency and Insurance, 2022 MM$	**$5.5**	**$5.5**	**$5.5**	**$5.5**	**$5.5**
Owner's Contingency (3%) (Note 4)	$4.9	$4.9	$4.9	$4.9	$4.9
Builders Risk Insurance (.317%) (Note 4)	$0.5	$0.5	$0.5	$0.5	$0.5
Total Screening Level Project Costs, 2022 MM$	**$170.3**	**$170.3**	**$170.3**	**$170.3**	**$170.3**
State Taxes (Note 4)	**$8.4**	**$0.0**	**$9.5**	**$6.4**	**$12.3**
Balance of Plant Materials and Products	$7.25	$0.0	$8.27	$6.44	$10.57
Labor and Services	$1.20	$0.0	$1.2	0	$1.75
CAPEX, 2022 MM$	**$178.71**	**$170.27**	**$179.74**	**$176.71**	**$182.59**
Location Adjusted CAPEX 2022 MM$	**$175.14**	**$178.78**	**$174.35**	**$178.47**	**$188.07**
Total Screening Level Project Costs, 2022 $/kWdc	**$875.70**	**$893.90**	**$825.79**	**$859.85**	**$876.87**
Total Screening Level Project Costs, 2022 $/kWac	**$1,138.41**	**$1,162.07**	**$1,073.53**	**$1,117.80**	**$1,139.93**
Demolition Costs (end of life cycle) 2022 MM$ (Note 5)	**$5.88**	**$6.30**	**$5.82**	**$6.06**	**$6.18**
O&M Cost, 2020 MM$/yr (Note 6)	**$4.2**	**$4.2**	**$4.2**	**$4.2**	**$4.2**
Module cleaning	$0.433	$0.433	$0.433	$0.433	$0.433
Vegetation and/or Pest Management	$0.158	$0.158	$0.158	$0.158	$0.158
System inspection and monitoring	$0.449	$0.449	$0.449	$0.449	$0.449
Component parts replacement	$0.327	$0.327	$0.327	$0.327	$0.327
Module replacement	$0.075	$0.075	$0.075	$0.075	$0.075
Inverter replacement	$0.779	$0.779	$0.779	$0.779	$0.779
Land Lease	$0.547	$0.547	$0.547	$0.547	$0.547
Property tax	$0.433	$0.433	$0.433	$0.433	$0.433
Insurance	$0.507	$0.507	$0.507	$0.507	$0.507
Asset management and security (Note 6)	$0.410	$0.410	$0.410	$0.410	$0.410
Operations administration	$0.057	$0.057	$0.057	$0.057	$0.057
O&M Cost, 2020 $/kWac-yr	**$20.87**	**$20.87**	**$20.87**	**$20.87**	**$20.87**
Co-Located Energy Storage -200 MW x 4 hr Capacity					
Add-On Costs					
Capital Costs, 2022 $MM	$325.83	$307.5	$328.4	$323.6	$330.4
Incremental O&M Cost, 2022 $MM/Yr	$6.46	$8.5	$8.5	$8.5	$8.5

Notes
Note 1. Solar capacity factor supplied by PAC.
Note 2. Base plant descriptions provided by PAC.
Note 3. Land is assumed to be leased throughout the project lifetime and is thus included in yearly O&M values.
Note 4. State Tax rates provided by PAC.
Note 5. Demolition costs are seen as an optional end-of-life cost, as other options like repowering the plant are available.
Note 6. Third party long-term service agreement costs are included in the asset management and security line item.

A - 12 Wind + Energy Storage

PACIFICORP RENEWABLE TECHNOLOGY ASSESSMENT SUMMARY TABLE WIND GENERATION					
PROJECT TYPE	Onshore Wind + BESS				
PROJECT LOCATION	Pocatello, ID	Arlington, OR	Monticello, UT	Medicine Bow, WY	Goldendale, WA
BASE PLANT DESCRIPTION	200 MW	200 MW	200 MW	200 MW	200 MW
ESTIMATED CAPITAL AND O&M COSTS					
BOP Project Capital Costs, 2022 $MM (w/o Owner's Costs)	**$263.1**	**$263.1**	**$263.1**	**$263.1**	**$263.1**
Wind Turbine Generators	$175.00	$175.00	$175.00	$175.00	$175.00
Met Mast	$1.05	$1.05	$1.05	$1.05	$1.05
Foundations	$14.19	$14.19	$14.19	$14.19	$14.19
Assembly & Installation	$8.57	$8.57	$8.57	$8.57	$8.57
Roads & Crane Pads	$9.49	$9.49	$9.49	$9.49	$9.49
O&M Building	$1.1	$1.1	$1.1	$1.1	$1.1
Collection System	$12.2	$12.2	$12.2	$12.2	$12.2
SCADA	$0.4	$0.4	$0.4	$0.4	$0.4
Switchgear/Substation (Note 2 & 3)	$15.9	$15.9	$15.9	$15.9	$15.9
Step-Up Transformer & Interconnection (Note 4)	$4.92	$4.92	$4.92	$4.92	$4.92
Aircraft Detection Lighting System	$0.90	$0.90	$0.90	$0.90	$0.90
EPC Fee (8%)	$19.49	$19.49	$19.49	$19.49	$19.49
Owner's Costs Without Contingency, 2022 $MM	**$5.5**	**$6.2**	**$5.5**	**$5.9**	**$6.4**
Project Design	$2.0	$2.0	$2.0	$2.0	$2.0
Owner's Engineer	$0.17	$0.17	$0.17	$0.17	$0.17
Land Lease & Development	$2.4	$2.4	$2.4	$2.4	$2.4
Permitting (Note 5)	$0.6	$1.4	$0.6	$1.1	$1.6
Wildlife Studies	$0.2	$0.2	$0.2	$0.2	$0.2
Eagle Take Permits	$0.09	$0.09	$0.09	$0.09	$0.09
Capital Spares	Included in O&M	Included in O&M	Included in O&M	Included in O&M	Included in O&M
Subtotal - Capital Costs, 2022 $MM	**$268.6**	**$269.3**	**$268.6**	**$269.0**	**$269.5**
Owner's Contingency (5% of Capital Cost)	$13.4	$13.5	$13.4	$13.5	$13.5
Total - Costs With Contingency, 2022 $MM	**$282.0**	**$282.8**	**$282.0**	**$282.5**	**$283.0**
State Taxes, $MM (Note 6)	**$14.7**	**$0.0**	**$14.3**	**$14.7**	**$21.5**
Balance of Plant Materials and Products	$12.5	NA	$14.3	$12.5	$18.3
Labor and Services	$2.2	NA	NA	$2.2	$3.2
CAPEX, 2022 $MM	**$296.73**	**$282.79**	**$296.32**	**$297.19**	**$304.46**
Location Adjusted CAPEX 2022 $MM	**$299.70**	**$294.10**	**$305.21**	**$294.21**	**$310.55**
Total Screening Level Project Costs, 2022 $/kW	**$1,498.51**	**$1,470.50**	**$1,526.07**	**$1,471.07**	**$1,552.76**
Demolition Costs (end of life cycle) 2022 $MM (Note 6)	**$11.89**	**$11.89**	**$11.89**	**$11.89**	**$11.89**
O&M Cost, 2022 $MM/yr	**$8.6**	**$8.6**	**$8.6**	**$8.6**	**$8.6**
O&M Cost, 2022 $/kW-yr	$43.0	$43.0	$43.0	$43.0	$43.0
Co-Located Energy Storage - 4 hr Capacity					
Add-On Costs					
Capital Costs, 2022 $MM	$318	$301	$321	$317	$326
Incremental O&M Cost, 2022 $MM/Yr	$8.46	$8.46	$8.46	$8.46	$8.46

Notes

Note 1. 20 MW Substation assumes: Tie in 230kV line through three disconnects, a single 230kV breaker connection, & a 1200A, 34.5kV GIS switchgear housed in a building.
Note 2. 200 MW Substation assumes: Three breaker ring 230kV AIS switchgear & (2) 2500A, 34.5kV GIS switchgear housed in a building.
Note 3. 20 MW Plant assumes (1) 30 MVA (230 kV/34.5 kV) transformer & 200 MW Plant assumes (2) 125 MVA (230 kV/34.5 kV) transformer. I one mile interconnection tie line is assumed for both
Note 4. Permitting cost assumes the permitting matrix from the 2022 PacifiCorp All-Source RFP is utilized.
Note 5. State Tax information provided by PacifiCorp.
Note 6. Reclamation costs included in Demolition costs. Demolition costs are seen as an optional end-of-life cost, as other options like repowering the plant are available.

A - 13 Wind + Solar + Energy Storage

PACIFICORP RENEWABLE TECHNOLOGY ASSESSMENT SUMMARY TABLE WIND + SOLAR + ENERGY STORAGE GENERATION					
PROJECT TYPE	WIND + SOLAR + ENERGY STORAGE				
PROJECT LOCATION	Idaho Falls, ID	Lakeview, OR	Milford, UT	Rock Springs, WY	Yakima, WA
BASE PLANT DESCRIPTION	200 MW	200 MW	200 MW	200 MW	200 MW
Nominal Output, MWac	200	200	200	200	200
Nominal Output, MWdc	260	260	260	260	260
Annualized Energy Production, MWh (Yr 1)	456,760	483,552	529,104	489,439	423,894
AC Capacity Factor at POI (%) (Note 1)	26.1%	27.6%	30.2%	27.9%	24.2%
Availability Factor, % (Note 2)	99%	99%	99%	99%	99%
Assumed Land Use, Acres (Note 2)	1600	1600	1600	1600	1600
PV Inverter Loading Ratio (DC/AC)	1.30	1.30	1.30	1.30	1.30
PV Degradation, %/yr (Note 2)	2nd year: 2% After 1st Year: 0.5% per year	2nd year: 2% After 1st Year: 0.5% per year	2nd year: 2% After 1st Year: 0.5% per year	2nd year: 2% After 1st Year: 0.5% per year	2nd year: 2% After 1st Year: 0.5% per year
Technology Rating	Mature	Mature	Mature	Mature	Mature
Permitting & Construction Schedule, year	2	2	2	2	2
ESTIMATED PERFORMANCE					
Base Load Performance @ (Annual Average)					
Net Plant Output, kW	200,000	200,000	200,000	200,000	200,000
ESTIMATED CAPITAL AND O&M COSTS					
EPC Project Capital Costs, 2022 MM$ (w/o Owner's Costs)	**$140.8**	**$140.8**	**$140.8**	**$140.8**	**$140.8**
Modules	$66.8	$66.8	$66.8	$66.8	$66.8
Inverter	$8.0	$8.0	$8.0	$8.0	$8.0
Structural BOS	$20.0	$20.0	$20.0	$20.0	$20.0
Electrical BOS	$10.0	$10.0	$10.0	$10.0	$10.0
Installer OH (Labor Costs)	$20.0	$20.0	$20.0	$20.0	$20.0
EPC OH (Equipment and Material)	$10.0	$10.0	$10.0	$10.0	$10.0
EPC Markup	$6.0	$6.0	$6.0	$6.0	$6.0
Owner's Costs, 2022 MM$	**$24.0**	**$24.0**	**$24.0**	**$24.0**	**$24.0**
Engineering & Development OH	$4.0	$4.0	$4.0	$4.0	$4.0
Transmission Line	$2.0	$2.0	$2.0	$2.0	$2.0
PII (permitting fee, interconnection, commissioning)	$8.0	$8.0	$8.0	$8.0	$8.0
Land Acquisition (Note 3)	$0.0	$0.0	$0.0	$0.0	$0.0
Owner's Project Development	$10.0	$10.0	$10.0	$10.0	$10.0
Owner's Project Management	PAC to input values	PAC to input values	PAC to input values	PAC to input values	PAC to input values
Owner's Legal Costs	PAC to input values	PAC to input values	PAC to input values	PAC to input values	PAC to input values
Contingency and Insurance, 2022 MM$	**$5.5**	**$5.5**	**$5.5**	**$5.5**	**$5.5**
Owner's Contingency (3%) (Note 4)	$4.9	$4.9	$4.9	$4.9	$4.9
Builders Risk Insurance (.317%) (Note 4)	$0.5	$0.5	$0.5	$0.5	$0.5
Total Screening Level Project Costs, 2022 MM$	**$170.3**	**$170.3**	**$170.3**	**$170.3**	**$170.3**
State Taxes (Note 4)	**$8.4**	**$0.0**	**$9.5**	**$6.4**	**$12.3**
Balance of Plant Materials and Products	$7.25	$0.0	$8.27	$6.44	$10.57
Labor and Services	$1.20	$0.0	$1.2	0	$1.75
CAPEX, 2022 MM$	**$178.71**	**$170.27**	**$179.74**	**$176.71**	**$182.59**
Location Adjusted CAPEX 2022 MM$	**$175.14**	**$178.78**	**$174.35**	**$178.47**	**$188.07**
Total Screening Level Project Costs, 2022 $/kWdc	**$875.70**	**$893.90**	**$825.79**	**$859.85**	**$876.87**
Total Screening Level Project Costs, 2022 $/kWac	**$1,138.41**	**$1,162.07**	**$1,073.53**	**$1,117.80**	**$1,139.93**
Demolition Costs (end of life cycle) 2022 MM$ (Note 5)	**$5.88**	**$6.30**	**$5.82**	**$6.06**	**$6.18**
O&M Cost, 2020 MM$/yr (Note 6)	**$4.2**	**$4.2**	**$4.2**	**$4.2**	**$4.2**
Module cleaning	$0.433	$0.433	$0.433	$0.433	$0.433
Vegetation and/or Pest Management	$0.158	$0.158	$0.158	$0.158	$0.158
System inspection and monitoring	$0.449	$0.449	$0.449	$0.449	$0.449
Component parts replacement	$0.327	$0.327	$0.327	$0.327	$0.327
Module replacement	$0.075	$0.075	$0.075	$0.075	$0.075
Inverter replacement	$0.779	$0.779	$0.779	$0.779	$0.779
Land Lease	$0.547	$0.547	$0.547	$0.547	$0.547
Property tax	$0.433	$0.433	$0.433	$0.433	$0.433
Insurance	$0.507	$0.507	$0.507	$0.507	$0.507
Asset management and security (Note 6)	$0.410	$0.410	$0.410	$0.410	$0.410
Operations administration	$0.057	$0.057	$0.057	$0.057	$0.057
O&M Cost, 2020 $/kWac-yr	**$20.87**	**$20.87**	**$20.87**	**$20.87**	**$20.87**
Co-Located Energy Storage -200 MW x 4 hr Capacity					
Add-On Costs					
Capital Costs, 2022 $MM	$325.83	$307.5	$328.4	$323.6	$333.4
Incremental O&M Cost, 2022 $MM/Yr	$8.46	$8.5	$8.5	$8.5	$8.5
Co-Located Energy Storage - 200 MW x 4 hr Capacity+200 MW Wind					
Add-On Costs					
Capital Costs, 2022 $MM	$599.22	$575.8	$606.5	$591.8	$616.6
Incremental O&M Cost, 2022 $MM/Yr	$17.08	$17.06	$17.06	$17.06	$17.06

Notes

Note 1. Solar capacity factor supplied by PAC.
Note 2. Base plant descriptions provided by PAC.
Note 3. Land is assumed to be leased throughout the project lifetime and is thus included in yearly O&M values.
Note 4. State Tax rates provided by PAC.
Note 5. Demolition costs are seen as an optional end-of-life cost, as other options like repowering the plant are available.
Note 6. Third party long-term service agreement costs are included in the asset management and security line item.

APPENDIX

B – TECHNICAL PARAMETERS

Appendix B

B - 1 Energy Storage Technical Parameters

ENERGY STORAGE - KEY TECHNICAL PARAMETERS BY TECHNOLOGY

	Parameter	Li-Ion	Flow	Iron-Air (single vendor - Form Energy)	Gravity	CAES
1	Power capacity: minimum, maximum (peak), spinning reserve	Typical grid-scale system has a min power capacity of 1MW+ per power conversion unit. There is no technical limit to the number of power conversion units connected in parallel within the system. As with any inverter-based system, a "virtual spinning reserve" function is inherent, supported by fast response to the max power output capacity and overload capability if the DC system is designed to support it (typically up to 120% of rated current at 10 sec duration, higher for millisecond-level durations). It should be noted that inverter-based systems can provide spinning reserve capability without the efficiency loss and the cost of using extra fuel	Typical system has a min power capacity of 78KW to 3 MW per power conversion unit. There is no technical limit to the number of power conversion units connected in parallel within the system. As with any inverter-based system, a "virtual spinning reserve" function is inherent, supported by fast response to the max power output capacity and overload capability if the DC system is designed to support it (typically up to 120% of rated current at 10 sec duration, higher for millisecond-level durations). Note that the response time of flow battery systems through the entire power output range can be slower as compared to Li-Ion BESS due to the need of change electrolyte flow rates. Still, it's within the range of conventional spinning reserve (rotating generators)	The basic Power Block has a capacity of 3.5 MW, 350MWh; spinning reserve capability in not known but as an inverter-based system it's expected to be available. The system is targeting very long duration (up to 100 hrs.).	Gravity storage is an emerging technology with no large-scale commercial facilities currently operating and no detailed technical information available publicly. A practical power output range has not yet been established. Energy Vault offers a modular system with 4MW/8-16hr minimum capacity, and also claims to have agreement for development of several Gigawatt-hour scale facilities in the US. Gravitricity offers systems in 1-20MW .25-8hr range. There are two different prime movers used in gravity energy storage systems - direct mechanical drive actuated by a falling weight, and a water or air turbine activated by process fluid (water or air) moving under influence of a solid weight (piston). Both have good spinning reserve capabilities due to inherently high ramp rates and relatively linear power delivery	Compressed Air Energy Storage is an emerging technology with several operating commercial pilots and several large-scale commercial projects under development. Detailed technical information is not publicly available. The power output range and its increments are controlled by the available turbomachinery (compressors and expanders). Standard turboexpanders are normally limited to 15 MW shaft power, however larger turbo-generators are likely to be developed in the future as the CAES technology matures. The spinning reserve capability of such plants will be similar to that of the simple cycle GT power plant. However, in Adiabatic CAES (A-CAES) systems that have the highest round trip efficiency, the response time and ramp rate may be affected by the responsiveness of the reheating cycle. This is expected to make the overall system response time closer to that of a CCGT power plant
2	Max system power capacity (if applicable, e.g., if there is a limit to the number of paralleled PCS units)	There is no technical limit to the number of PCS units that can be paralleled, within the range of existing power plant output capacities	There is no technical limit to the number of PCS units that can be paralleled, within the range of existing power plant output capacities	There is no technical limit to the number of Power Block units that can be paralleled, within the range of existing power plant output capacities	There is no technical limit to the number of mechanically or hydraulically-driven generator units that can be paralleled, within the range of existing power plant output capacities	There is no technical limit to the number of turbogenerator units that can be paralleled, within the range of existing power plant output capacities
3	Voltage/phase	The majority of Power Conversion Systems (bi-directional inverters) have their output at 480VAC or 600VAC, 3-phase. Many PCS systems also have built-in transformer allowing interconnection at medium voltage (e.g. 13.8kV)	The majority of Power Conversion Systems (bi-directional inverters) have their output at 480VAC or 600VAC, 3-phase. Many PCS systems also have built-in transformer allowing interconnection at medium voltage (e.g. 13.8kV)	No information available; expected to be similar to other inverter-based ESS systems	Gravity systems use standard industrial/power plant generators that typically have medium-voltage terminal output (6-15kV), 3-phase	CAES systems use standard industrial/power plant generators designed for turbine applications, which typically have medium-voltage terminal output (6-15kV), 3-phase
4	Energy storage capacity for a base unit/minimal functional system size (scalable by using multiple units)	Typically ranges from 250kWh to 4 MWh	Typically ranges from 22kWh to 1 MWh	350MWh	25 -20MWh	Pilot CAES plants have been operating at low capacities but a commercially feasible CAES facilities currently under development are in the 100MW+, long-duration category (such as PG&E San Joaquin CAES, at 300MW/10hr). The existing CAES systems use a scalable, but not modular technology with regards to their energy storage component
5	Max system energy storage capacity (e.g., if there is a limit to the number of paralleled ES units)	There is no technical limit to the number of energy storage units that can be paralleled	There is no technical limit to the number of energy storage units that can be paralleled	There is no technical limit to the number of energy storage units that can be paralleled	There is no technical limit to the number of energy storage units that can be paralleled	There is no technical limit to the capacity of compressed air energy storage, within the existing range of power plant capacities
6	Response time: from standby (cold stby, if applicable to specific technology) to 100% power output	~1 sec (conservative)	~1-2 sec	No information available; expected to be similar to other inverter-based ESS systems; however the ramp rate is unknown	Not available, technically possible to match battery-based technology performance	60-400 sec depending on the compressor and expander utilized
7	Response time: from 100% charging input to 100% output	~2 sec (<200 ms in frequency response applications)	~2 sec	No information available; expected to be similar to other inverter-based ESS systems; however the ramp rate is unknown	Not available, technically possible to match battery-based technology performance	60-400 sec depending on the compressor and expander utilized
8	C-rate range	1 - .16	<.25	No information available	Data not available. Typically designed for long duration applications (4-8++ hrs. or .25C - .125C).	Data not available. Depends on the ratio of storage vs compressor/expander capacity. Typically designed for long duration applications (5-10++ hrs., or .2C- .1C)
9	C-curve for charging and discharging	Charging capacity is linear 10% true SOC and 75-90% (depending on cell chemistry) true SOC, asymptotically slowing above that range, leading to the practical SOC range not using the full physical SOC range	<.25 Linear for charging and discharging within full SOC range.	No information available	Data not available. Charging and discharging capacity is expected to be linear within the full SOC range.	Data not available. Charging capacity is expected to be an S-curve, with significant deviations from linear at the extreme true SOC values. Likely mitigated by setting practical SOC range narrower than the true SOC range, similar to Li-on battery based energy storage
10	Round trip efficiency (AC in to AC out), excluding auxiliary loads	PNNL (historical) - 83%, vendor supplied data 91-94% (year 0, including thermal management loads); Inverter-only: 98.3% at full load	65% (Vn-RedOx, PNNL); vendor supplied data ~72%	38% (at full power, including auxiliary loads and PCS losses)	83% (PNNL), vendor supplied data - 81-92%	70% (eesi.org, for A-CAES), 52% (PNNL, historical)
11	Auxiliary power consumption for a minimally sized system block (scalable by paralleling many blocks)	1-10% of nameplate power depending on ambient conditions, load and cooling system efficiency	5-10% of nameplate power, depending on load	No information available	Data not available, expected to be significantly lower than Li or Flow BESS systems as no cooling or circulation pumps required	Data not available, expected to be lower than Li or Flow BESS systems etc. as no cooling or circulation pumps required. However, heat recovery for A-CAES system may introduce such loads
12	Guaranteed system availability	Varies by vendor, ~97% is typical	Data not available	No information available	Data not available	Data not available
13	Capacity degradation rate (calendar)	1%/year	<1%/year	No information available	No vendor data available, anticipated to be 0%/year	No vendor data available, anticipated to be 0%/year
14	Cycling capacity degradation (assuming full charge-discharge cycle at 1 cycle per day)	vendor data used in performance guarantees - on an average 2.2%/year (including calendar degradation and cycling degradation at 1 cycle per day)	No vendor data available, anticipated to have low or no cycling degradation (provided timely electrolyte exchange)	No information available; indirectly - warranty covers 10 years at 13 full cycles per year	No vendor data available, anticipated to be 0%/year	No vendor data available, anticipated to be 0%/year provided proper turbomachinery O&M
15	Design lifespan of the system assuming 365 cycles per yr.	16 yrs (PNNL data); vendor data: 15-20 yrs.	12 yrs. (Vn-RedOX, PNNL); vendor data - 50+ yrs.	No information available; indirectly - warranty covers 10 years	vendor data - 49+ yrs.	60 yrs. (PNNL)
16	Max number of lifetime system charge/discharge cycles	LFP: min 3,000-4,000 Equivalent Full Cycles (without losing more than 20% of initial capacity)	Unlimited (with electrolyte and electrode replacement)	130	Unlimited (with proper mechanical machinery O&M)	Unlimited (with proper turbomachinery O&M)
17	Major required service and maintenance required during the design lifespan of the system	Capacity maintenance (adding battery modules to compensate for capacity degradation); coolant replacement (for liquid-cooled systems)	Electrolyte replacement, scheduled replacement of electrolyte pump and valve components	No information available	Mechanical maintenance (lubrication, bearing and linkage service etc.), pump and turbine component replacement (for systems using a working fluid)	Compressor and turboexpander maintenance (lubricant change, bearing service); circulation pumps and valves service (for A-CAES)

APPENDIX O – WASHINGTON 2021 IRP TWO-YEAR PROGRESS REPORT ADDITIONAL ELEMENTS

Introduction

Washington passed the Clean Energy Transformation Act (CETA) in 2019, which 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, beginning January 1, 2023, the Company must file a two-year progress report at least every two years after PacifiCorp has filed its IRP.[2] This two-year progress report must include the following:

- Updated load forecast, demand-side resource assessment, including a new conservation potential assessment; resource costs; and portfolio analyses and preferred portfolios;
- Other updates necessary due to changing state or federal requirements, or significant changes to economic or market forces; and
- Update any elements found in the utility's current clean energy implementation plan (CEIP).[3]

The Company's updated load forecast can be found in Volume 1, Appendix A; demand-side resource assessment and new conservation potential assessment can be found in Chapter 6 and the ***Specific Actions*** section below; resource costs can be found in Volume I, Chapter 7; and relevant portfolio analyses can be found in Volume I, Chapters 8 and 9, and the ***Interim and Specific Targets*** section below.[4] Relevant state and federal policy updates, as well as changes to economic or market forces, can be found in Volume I, Chapter 3.[5]

Aligned with the refiled CEIP,[6] this 2021 IRP Two-Year Progress Report includes updates on the following CEIP elements: Interim and Specific Targets; Updated Inputs, including portfolio

[1] 2019 WA Laws Ch. 288.
[2] WAC 480-100-625.
[3] *Id.* -625(4).
[4] *Id.* -625(4)(a).
[5] *Id.* -625(4)(b).
[6] PacifiCorp filed its first Clean Energy Implementation Plan (CEIP) on December 29, 2021, with the Washington Utilities and Transportation Commission (WUTC) in docket UE-210289. The Company filed a Revised Errata to the CEIP to make a small correction to a workpaper that resulted in a change in the calculated incremental cost. Consistent with UE-220376, Order 06, the Company refiled its 2021 CEIP on March 13, 2023, and relevant CEIP elements are included in this 2021 IRP Two-Year Progress Report.

analysis and preferred portfolios; Customer Benefit Indicators; Specific Actions, including both supply and demand-side actions; Incremental Costs; Public Participation; and Annual Reporting.

Each of these updated CEIP elements are discussed below. Additionally, consistent with WAC 480-100-650, more detailed and specific reporting on CEIP targets, actions, and CBIs will be included in the Company's annual clean energy progress report due this summer, and CEIP biennial update due later this fall.

Interim and Specific Targets

CETA's clean energy transformation requires Washington utilities to eliminate coal-fired resources from its allocation of electricity to Washington retail electric customers by 2026; ensure all retail sales of electricity to Washington electric customers are greenhouse gas neutral by 2030; and 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 by 2045.[7]

Prior to 2045, CETA allows for up to 20 percent of the greenhouse gas neutral standard to be met with alternative compliance in the form of alternative compliance payments, unbundled RECs, energy transformation projects, or energy recovery from a municipal solid waste facility.[8] To achieve the 2045 target, the clean energy standard must be met with 100 percent non-emitting generation or electricity from renewable energy resources. Furthermore, PacifiCorp must demonstrate that it "has made progress toward and has met the standards in this section at the lowest reasonable cost."[9]

Consistent with these requirements and WAC 480-100-640, the Company proposes interim targets to demonstrate its trajectory toward meeting CETA's decarbonization targets. Updated interim targets are based on data and methodologies consistent with portfolio development and modeling in Volume 1, Chapters 8 and 9, and with CEIP requirements. Specifically, CEIP targets are demonstrated for a least-cost, least-risk portfolio optimized under the price policy assumption that includes societal cost of greenhouse gas emissions (SCGHG).[10]

As shown in Volume I, Chapter 8 (Modeling and Portfolio Evaluation), Figure 8.4 – the SCGHG starts at just over $80/ton in 2023 and reaches about $170/ton in 2042. In addition to the assumed carbon dioxide price, there is an additional forecasted cost of allowances under the cap-and-invest program established in the Climate Commitment Act passed by Washington Legislature in 2021. This forecasted allowance cost is applied to all emissions from the Chehalis natural gas plant located in Washington. The modeled allowance cost reflects analysis conducted by Vivid

[7] WAC 480-100-610(1-3).
[8] RCW 19.405.040(1)(b).
[9] WAC 480-100-610(5).
[10] The SCGHG dispatch adder is modeled in both the resource acquisition decision (capacity expansion in the LT model), and in operations (dispatch in the MT and ST models) as described in Volume I, Chapter 8 (Modeling and Portfolio Evaluation).

Economics for the Washington Department of Ecology and starts at $58/ton in 2023.[11] For more discussion of the system-wide portfolio impacts of the SC price-policy assumptions and CETA-related portfolio impacts, see results in Volume I, Chapter 9 (Modeling and Portfolio Selection Results).

Based on these updated portfolio inputs, the Company anticipates supplying 26 percent renewable and non-emitting energy to serve Washington retail sales in 2023, increasing to 33 percent in 2025, to 82 percent in 2030, and finally over 100 percent beginning in 2032 and maintaining this percentage for the remainder of the Company's planning period.

Interim Targets

This section includes PacifiCorp's interim compliance targets for the first CETA action period (2022-2025), and to achieve CETA's 2030 and 2045 targets.

Figure O.1 reports PacifiCorp's updated interim targets that are derived from the portfolio denoted W-10 CETA.[12] This portfolio was developed to meet CETA's 2030 and 2045 decarbonization targets under the SCGHG price policy assumption. In the figure interim targets are divided into two forecast ranges: the first focuses on meeting CETA's 100 percent GHG neutrality standard by 2030, and the second focuses on meeting the 100 percent non-emitting and renewable energy target by 2045. As shown in the figure, the Company expects to have achieved CETA's ambitious decarbonization targets well over a decade in advance of the 2045 deadline.

Post-2030, the last three years to reach the 2045 objective are beyond the Company's current 20-year study period. Rather than creating extrapolated and imprecise forecasts for every data point underlying the analysis to extend into 2045, the company has extrapolated the last three years of data based on the already optimized and established trajectory. However, this exercise was unnecessary given that the portfolio shows 100 percent clean energy as a percentage of Washington retail sales by 2032.

[11] Washington DOE Summary of market modeling and analysis of the proposed Cap and Invest Program, at 4 (Jun. 2022) (available here: https://ecology.wa.gov/DOE/files/4a/4ab74e30-d365-40f5-9e8f-528caa8610dc.pdf; accessed Mar. 31, 2023).

[12] Several portfolios were developed to analyze the impacts of CETA in various planning scenarios, and are defined in Volume I, Chapter 8 (Modeling and Portfolio Evaluation).

Figure O.1 - Interim Targets

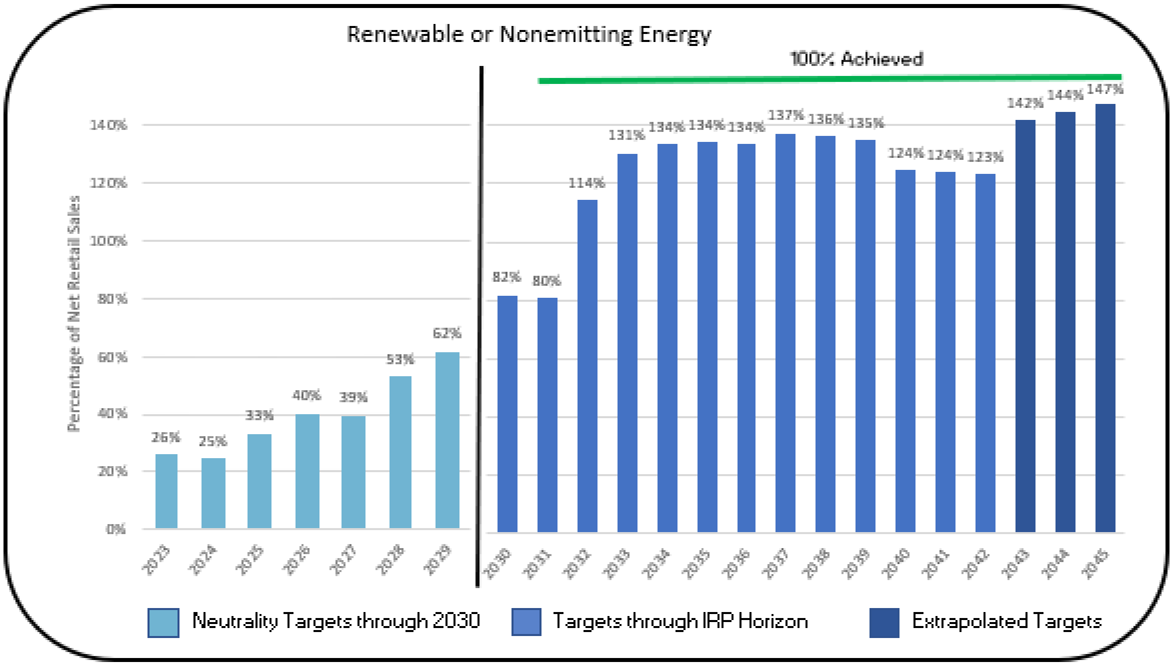


Table O.1 below reports updated interim targets for the Company's first CEIP action period for years 2022 through 2024, reported as annual megawatt hours of energy rather than as percentages. Since this two-year IRP progress report is forward-looking, portfolio inputs, outputs, and interim targets begin from year 2023. However given the Company's current CEIP focuses on the CEIP compliance period from 2022 to 2025, this same compliance period is reflected below. The values for 2022 are from the Company's March 13, 2023 Refiled CEIP and have not been updated, and are informed by the company's historical performance under median water conditions, a factor in developing expected resource behaviors and Washington retail sales.

Table O.1 - Interim Compliance Targets (MWh)

	2022[1]	2023	2024	2025	Total
Retail Electric Sales	4,051,128	4,128,751	4,141,107	4,106,386	16,427,372
Projected Renewable and Non-emitting Energy	1,262,111	1,081,277	1,028,236	1,367,667	4,739,291
Net Retail Sales	2,789,017	3,047,474	3,112,871	2,738,719	11,688,081
Target Percentage	31%	26%	25%	33%	
Interim Compliance Target	1,262,111	1,081,277	1,028,236	1,367,667	4,739,291

[1] Originally estimated target for 2022 based on Refiled 2021 CEIP, March 13, 2023

These updated interim targets reflect both updates from the Company's portfolio results, as well as updated resource allocation assumptions. Importantly, increases in system load, changes in price curves and fuel inputs, and development in federal regulation like the Ozone Transport

Rule, have driven significant growth in system renewable resources across the planning horizon. However, ongoing wholesale energy market volatility has forced the Company to consider options to mitigate increasing net power costs that adversely affect PacifiCorp's near-term CETA targets. Compliance with CETA continues to be supported by the IRP with the addition of non-emitting system resources. Ongoing negotiations in MSP, updated REC assumptions, and a realignment of assumptions about uncertain future Washington resource allocations have all led to a lower percentage of system renewable energy for Washington customers in the near-term as compared to the Company's current CEIP.

Given these updates, the Company estimates by 2025 that 33 percent of Washington retail sales will be served by renewable and non-emitting energy, and as discussed above, the Company will substantially decarbonize its system and achieve CETA's 2045 requirements almost a decade early.

Target Development

Updated interim target development is consistent with PacifiCorp's Refiled 2021 CEIP, Chapter 1, where the Company's Washington allocation of the updated CEIP-compliant portfolio of resources was analyzed based on an updated forecast of retail electric sales to Washington.[13] This section discusses the assumptions that informed these updated interim targets.

To estimate the amount and mix of energy forecasted to serve Washington customers for the 2023-2045 period, PacifiCorp summed annual generation from its qualifying resources allocated to Washington customers 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.[14] The allocations assumed for Washington in this update 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, the company made the assumptions set forth below. Generally, where a resource is assumed to generate 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

[13] PacifiCorp's Revised 2021 CEIP can be found at: https://apiproxy.utc.wa.gov/cases/GetDocument?docID=277&year=2021&docketNumber=210829.

[14] 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.

non-emitting resources was also CETA compliant, namely hydroelectric, nuclear and hydrogen non-emitting peaking plants.[15] In summary, the resource allocation assumptions are:

1. Allocation of energy for all system renewable resources, existing and proxy, are allocated according to system-generation (SG) factors, consistent with the WIJAM.
2. Allocation of energy for new 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 Unites 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 by the end of 2025. It is assumed that in the event a coal-fueled resource converts to gas before 2026, that Washington customers can participate until the end 2029.
    b. Washington customers participate in two gas-fired units, Chehalis and Hermiston, through the end-of-life.

Given the assumed allocations of resource energy and costs to Washington, CETA-compliant energy is determined given the following:

1. For 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 renewable and non-emitting resources were assumed to be CETA compliant, including wind, solar, geothermal, hydro, nuclear and hydrogen non-emitting peaking plants. 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 were defined as total energy served to customers annually, net of distributed generation, existing and optimized energy efficiency and demand-side management (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).[16] CETA compliance targets were calculated annually as a percentage of Washington retail electric

[15] 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".

[16] RCW 19.405.020(36)(a)

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.

For purposes of this CEIP, PacifiCorp relies on the use of unbundled RECs to satisfy the alternative compliance component of the 2030 and 2031 greenhouse gas neutral standard. PacifiCorp may meet up to 20 percent of its aggregate retail electric sales over the four-year compliance period with alternative compliance from January 1, 2030, through December 31, 2044.

For further discussion specific to development of the CETA-compliant portfolio and interim targets, please see subsection Interim Target Shortfall Resolution.

Specific Targets

Renewable energy targets, energy efficiency and demand response targets will evolve from the ongoing CEIP, based on updated outputs and analysis from this IRP Progress Report. The Company's November 1, 2023 Biennial CEIP Update will provide updates to all general CEIP requirements, including specific targets.

Customer Benefit Indicators

As part of its CEIP compliance report to be filed July 1, 2023, PacifiCorp will report and track customer benefit indicators (CBIs) that are identified in Chapter 2 of the Company's CEIP. These metrics will report on the progress made in each CBI as PacifiCorp moves through the four-year CEIP cycle. Furthermore, PacifiCorp is considering additional input on the Company's CBIs in response to public comment and stakeholder feedback received in Docket UE-210829. Of note, the Washington Department of Health (DOH) recently updated the agency's highly-impacted communities (HIC) analysis in January 2022.[17] Based on this DOH update, the Company concluded there is one additional HIC located within PacifiCorp's Washington service territory compared to what was considered in the Company's 2021 CEIP. The Company is in the process of including this additional HIC within the baseline and will account for it when developing metrics for the July 1, 2023, compliance report.

The process of updating the metrics for the July 1, 2023, filing will be based largely on survey results. As was the case with the Company's December 30, 2021, filing, the CBI metrics will require PacifiCorp to use survey responses to identify energy burden for vulnerable populations in the Washington service area. This survey is expected to launch in April 2023 and will include both an email and telephone effort to accumulate necessary data.

[17] *See generally,* Washington Department of Health, Information by Location (IBL) (available here: https://doh.wa.gov/data-and-statistical-reports/washington-tracking-network-wtn/information-location).

Specific Actions

This section provides updates on the Company's supply- and demand-side resource actions taken over the past two-year period. As discussed below, the Company has procured substantial non-emitting and renewable resources and taken significant steps to improve or expand its demand-side resource programs and opportunities.

Supply-Side Resource Actions

The 2020AS RFP has concluded with the procurement of 1,792 MW of wind resources, 495 MW of solar additions, and 200 MW of battery storage capacity paired with solar. All of these resources have 2024 or 2025 CODs and will contribute to PacifiCorp's renewable energy and carbon reduction goals.

PacifiCorp procures for its system needs across its six-state territory. Prior to the passage of CETA and with the 2020 procurement effort, there were no cost-competitive Washington bids and therefore limited alignment with the CBIs that resulted from a 2021 stakeholder engagement process.

Following the 2021 IRP filing, PacifiCorp issued its first request for proposal to take into consideration the requirements of CETA. The ongoing 2022 all source request for proposals (2022AS RFP) was filed in Washington and received approval in three states after a lengthy stakeholder process. It was subsequently issued to the market on April 29, 2022. PacifiCorp hired an independent evaluator (IE) to oversee the process, with the oversight of the Washington Commission. In December 2022, PacifiCorp bid twelve eligible self-build (benchmark) resources into the 2022AS RFP, and on March 14, 2023, PacifiCorp received 302 bids from 74 developers and 93 different projects sites across six states. A final shortlist is expected to be released by late Q2 2023 or early Q3 2023, with resources contracted by the end of Q4 2023. PacifiCorp will consider its Washington CBIs before making a final shortlist decision.

Demand-Side Resource Actions

Since the original CEIP filing, PacifiCorp has made the following changes and updates to demand-side resource programs to help increase benefits to named communities and achieve goals informed by our Equity Advisory Group (EAG):[18]

Residential Energy Efficiency

- Enhanced incentives for windows in multi-family units on residential rate schedules. Initial focus on buildings in highly impacted communities.
- Continued direct install residential lighting in multi-family units with focus in highly impacted communities.

[18] These changes and updates were identified as CEIP Utility Actions in the 2022-2023 DSM Business Plan filed with the 2022-2023 Biennial Conservation Plan on November 1, 2021 (Docket UE-210830). The same actions were included in the CEIP, and the 2023 Annual Conservation Plan filed November 15, 2022 (Docket UE-210830), included an update on the Utility Actions.

- Maintained and expanded general purpose lamp buy down in "dollar stores" in highly impacted communities.
- Continued manufactured home direct install duct sealing and lighting. Continue focus in highly impacted communities.
- Continued promoting new construction offerings for multifamily, and single family units. Continue focus in highly impacted communities.
- Develop pathways for non-electric, non-natural gas upgrades in named communities.
    - Serve named community residential customers who use non-electric and non-natural gas fuel sources in their primary heating systems by offering incentives for decommissioning these systems and installing ductless heat pumps.

Low Income Weatherization

- Increased funds available for repairs from 15 percent to 30 percent.
- Permitted installation of electric heat to replace permanently installed electric heat, space heaters or any fuel source except natural gas with adequate combustion air as determined by the Agency. The changes are designed to promote the installation of electric heat and minimize use of wood heat, solid fuels or natural draft equipment in specific applications where combustion safety (and indoor air quality) cannot be maintained.

Non-residential energy efficiency

- Increased outreach and participation for small businesses and named community small businesses identified by census tract and rate schedule.
    - Created a new offer within the current small business enhanced incentive offer targeting the smallest businesses using less than 30,000 kilowatt-hours per year and Named Community small businesses on Schedule 24.
    - Targeted a portion of company initiated proactive outreach to small businesses located in highly impacted communities. Continued to tie proactive outreach to approved small business vendor capacity to respond to customer inquiries.
- Offered approved small business lighting vendors a higher vendor incentive for completed lighting retrofit projects with small businesses located in highly impacted communities.
- For 2023, the program seeks to create a new offer within the current small business offer to include enhanced incentives for select non-lighting measures.
- Continue development of program materials in Spanish and increase outreach to Latinx and Tribal community groups.

Specific to energy efficiency actions, the company will document its progress regarding the CBIs and energy savings targets in its annual clean energy progress report filed on July 1st each year

Specific to energy efficiency targets, PacifiCorp filed its 2023 Annual Conservation Plan on November 15, 2022 (Docket UE-210830). This plan includes an updated forecast for 2022-2023 which indicates a shortfall relative to the two-year target established via the process for target setting established by the Energy Independence Act (WAC 480-109-100). The final results for 2022-2023 will be in PacifiCorp's Biennial Conservation Report due June 1, 2024. On November 1, 2023, PacifiCorp will file its Biennial Conservation Plan with the targets for 2024-2025. Those targets will be based on updated information relative to the CEIP and will align with those accepted from this ongoing two-year Energy Independence Act target setting process.

PacifiCorp also has also taken actions to develop demand response resources to work towards stated interim targets. Since the original CEIP, PacifiCorp received approval for Schedule 106, which is an enabling demand response tariff that supports multiple market driven programs. Schedule 106 provides a regulatory framework that includes a fast and flexible change process while at the same time enabling transparent customer information for the benefit of all stakeholders. Each new demand response program will use Schedule 106 for enablement, communication, and tracking. The Company has taken the following program-specific demand response actions in Washington:

Commercial and Industrial Curtailment
A commercial and industrial program was approved and effective in December 2022. The program focuses on enrolling connected end use loads available during various dispatch periods. Event communication and control occurs through a Program Administrator-provided, two-way communications device (communicating via cellular signals) installed at the customer site.

Irrigation Load Control
This program was approved and became effective in August 2022. It focuses on enrolling agricultural irrigation pumps with the highest connected loads during the available dispatch hours in the summer during the irrigation season with incentives differentiated based on dispatch notification option. The program relies on field-installed direct load control (DLC) devices to send signals to pumping equipment for reduction of irrigation loads for participating customers.

Bring your own Thermostat and Water Heater Direct Load Control
The company is preparing to file, for approval, a program to deliver curtailable end-use loads from residential HVAC equipment communicating through customers' web-enabled thermostats and electric water heaters via Wi-Fi enabled communication devices. The Company is currently estimating an effective date in 2023 for this program.

Batteries
This program is under consideration and is currently in the preliminary stages of planning. The program would potentially target residential – and possibly commercial – customers who have Wi-Fi connection to incentivize the use of individual batteries for system wide-integration in support of overall grid management.

While the Company has made progress on these demand response actions since filing the CEIP, as described above, program implementation is just beginning to ramp up. As noted in the CEIP, "Total demand response volume is subject to change based on timing of programs and contract negotiations."[19] As implementation and development of these new programs continues, progress toward and change to the interim targets will likely occur as expectations regarding demand response volumes are informed by actual effective program dates, leading to improved planning

[19] See CEIP page 22.

estimates. Volumes attained by the end of the CEIP period, 2025, will likely be different from the initial CEIP forecast of 37.4 MW.

Specific to demand response actions, the company will document its progress regarding the CBIs and capacity savings targets in its annual clean energy progress report filed on July 1st each year.

Time-of-Use Pilots

Beginning in May 2021, PacifiCorp launched residential and non-residential service time of use pilots. The residential pilot (Schedule 19) targets single family residential customers and is available for up to 500 customers on a first-come, first-served basis. The non-residential time of use pilot (Schedule 29) targets non-residential customers with loads under 1,000 kW and is available for up to 100 customers on a first-come, first-served basis.

Incremental Cost

An update to the incremental cost calculation is provided for the remaining years in the CEIP period, 2023 – 2025. The CEIP portfolio, W-10 CETA, was specifically optimized and designed to meet CETA standards. This portfolio is contrasted to the alternative lowest reasonable cost portfolio as defined in rule and is denoted P-SC or referred to as the Alternative Portfolio.[20] Any differences in cost between the CEIP portfolio and the Alternative Portfolio are considered incremental costs, costs directly resulting from actions taken to comply with requirements under RCW 19.405.040 or 19.405.050. These incremental costs include items like CETA-driven impacts to electricity generation, energy efficiency, new programs to support customers, and program management, that can be measured for the current CEIP period.

The methodology to calculate the updated incremental cost is consistent with the methods described in the refiled 2021 CEIP. Only the modeled IRP-based costs were updated at this time. Given the updated portfolio outcomes, the incremental costs to comply with CETA is $2.13 million on average per year.

Interim Target Shortfall Resolution

To develop the CEIP portfolio, the base portfolio, P-SC, was evaluated against CETA requirements that Washington-supplied energy would be 100% greenhouse gas neutral with up to 20 percent of this amount supplied by unbundled RECs beginning in 2030, and 100 percent clean and non-emitting by 2045.

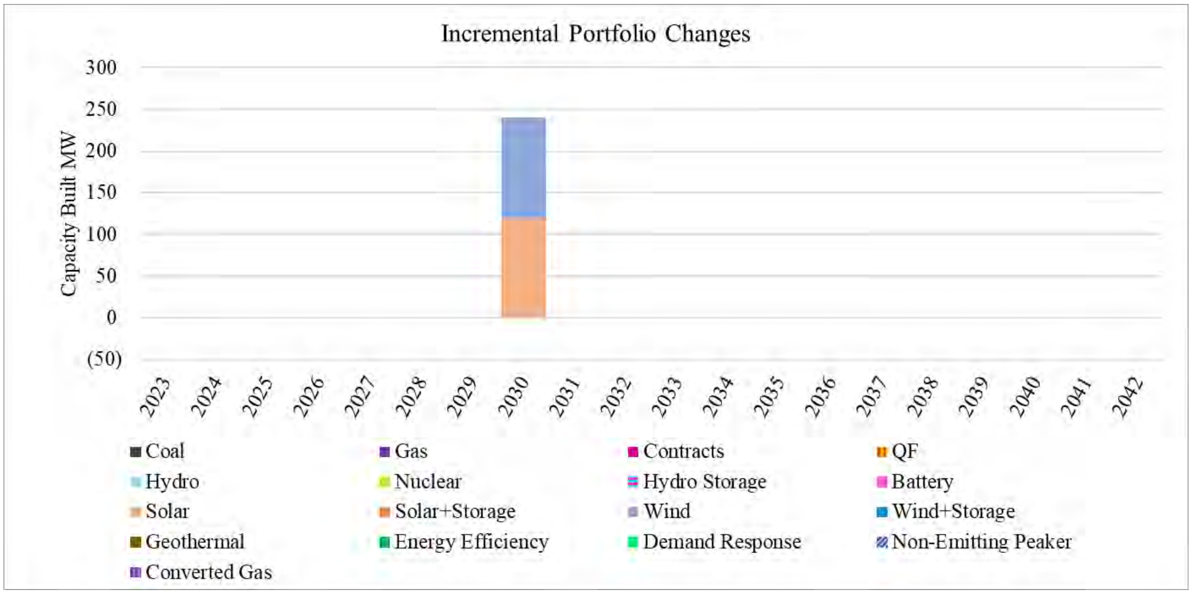
Given the system optimized portfolio under the SCGHG price policy assumption and assumed resource allocations to Washington customers, the Company identified a small compliance shortfall in 2030 and 2031. In years 2032 and beyond, the portfolio resources generated enough renewable and non-emitting energy to Washington to meet 100 percent of need. These compliance shortfalls were identified by calculating the amount of additional renewable or non-emitting energy that would be needed to meet at least 80 percent of Washington retail sales.

[20] Several portfolios were developed specific to Washington CETA legislation and are defined in Volume I, Chapter 8.

A compliance shortfall of 67 MW of average annual capacity was identified in 2030, and a slightly larger shortfall of 72 MW average annual capacity resulted for 2031.

To reach the target of at least 80 percent non-emitting energy in 2030-2031 at least-cost, and without the need for additional transmission lines, small-scale renewable capacity was added in Yakima, Washington. Specifically, 120 MW of installed capacity of small-scale solar and 120 MW of installed capacity of small-scale wind was added in Washington in 2030. The incremental small-scale resources were added only for CETA-compliance, on top of an optimized system portfolio developed under the SCGHG price policy assumption, as shown in Figure O.2. Thus, the incremental small-scale solar and wind was allocated situs to Washington and would represent an incremental cost in 2030 and 2031.

Figure O.2 - Incremental Portfolio Change: W-10 CETA delta P-SC



These incremental actions resulted in the CEIP-compliant portfolio, W-10 CETA, and the associated interim targets and incremental costs.

Revenue Requirement Methodology

Incremental costs included for consideration in this CEIP can be broadly considered in two categories – IRP modeled incremental costs, and non-IRP modeled incremental costs. IRP modelled incremental costs were identified through the comparison of changes in investment costs between the CEIP portfolio and the Alternative Portfolio, described above, for the years 2023 - 2025. Per rule WAC 480-100-660(1), the only differences in investment decisions between the two portfolios described are a direct result of CETA requirements, determined to be met in a least-cost least-risk manner. Incremental investments and expenses were identified from the comparison of the two portfolios and summarized on an annual, nominal and levelized basis for the remaining compliance years in the CEIP. Table O.2 summarizes the resource-driven incremental expenses identified. However, note that the column for 2022 was not updated and is equivalent to the modeled incremental cost shown in the Company's current CEIP.

Table O.2 - Annual Modeled Impacts of CETA

	Compliance Year			
($million)	**2022**	**2023**	**2024**	**2025**
Fuel Costs	-	(0)	0	(1)
Other Variable	-	0	0	0
Energy Efficiency	-	-	0	-
Net Market Purchases	-	(0)	(0)	(3)
Emissions	-	1	0	2
Deficiency	-	-	(0)	(0)
Fixed Costs	-	-	(0)	0
Total	**-**	0	(0)	(2)

There are no incremental resource additions in the CETA-compliant portfolio during the CEIP compliance window. Any differences in the annual modeled costs over the period are due to negligible movements in dispatch.

It is assumed that other non-modeled costs, as presented previously in the revised 2021 CEIP, have not changed and are shown in Table O.3.

Table O.3 - Non-modeled Impacts of CETA ($million)

CETA Expenses	**2023**	**2024**	**2025**	**Description of Cost Item**
CEIP Management, Coordination & Communication	0.57	0.58	0.60	Additional Staffing to help coordinate, facilitate and strategic planning for CEIP
Enhanced Outreach & Communication	0.39	0.39	0.40	Outreach and materials for EAG and Public meetings
External Data Support	0.17	0.18	0.18	Vendor expense for data support
CETA-specific DSM Program Expenses	1.26	1.29	1.32	Costs incurred to enhance reach and equitable distribution of DSM programs
Total	**2.40**	**2.45**	**2.50**	

Taking the estimated incremental costs identified based on methodologies described in this report, the company calculated an annual revenue requirement using the standard revenue requirement formula:

$$\textit{Revenue Requirement} = \textit{Rate of Return} \times (\textit{Net Rate Base}) + \textit{Operating Costs}$$

Using the above formula, the estimated annual revenue requirement for the remaining years in the compliance period is as follow, presented in Table O.4.

Table O.4 - Revenue Requirement of Cost Estimates

	Compliance Year			
$-Millions	**2022**	**2023**	**2024**	**2025**
Revenue Requirement				
Fixed Costs[1]	-	-	(0.00)	0.00
Variable Costs				
Fuel Costs	-	(0.03)	0.03	(0.68)
Variable O&M	-	0.00	0.01	0.04
Energy Efficiency	-	-	0.00	-
Net Market Purchase	-	(0.04)	(0.12)	(3.11)
Emissions	-	0.54	0.10	2.16
Deficiency	-	-	(0.07)	(0.06)
Total Variable Costs	-	0.47	(0.04)	(1.64)
Administrative & General				
DSM Program Costs	1.24	1.26	1.29	1.32
Outreach Costs	0.40	0.37	0.38	0.39
Materials	0.01	0.01	0.01	0.01
Staffing	0.56	0.57	0.59	0.60
Data Support	0.17	0.17	0.18	0.18
Total Revenue Requirement [2]	**2.38**	**2.86**	**2.40**	**0.86**
Average Revenue Requirement	**2.13**			

Notes:

1. Incremental fixed cost are identical between the CEIP portfolio (W-10 CETA) and Alternative Portfolio (P-SC) during the CEIP compliance window. Fixed costs are reported in the respective portfolios at a nominal and levelized basis, which reflects both a return on and return of component.

2. Estimated revenue requirement is calculated based on incremental costs derived by comparing IRP portfolios. Actual cost recovery will ultimately be determined by the prevailing cost allocation methodology approved in Washington at the time recovery is sought.

The annual threshold for Alternative Means of Compliance as stated and calculated in the Revised CEIP filed March 13, 2023, has not changed and is equal to $16,667 million. Thus, based on current forecasts, the estimated incremental costs identified for implementation of CETA from 2022 to

2025 are within the annual threshold amount. As such, the Company will not rely on RCW 19.405.060(3) as a means of alternate compliance to achieve CETA's requirements.

Public Participation

The Company has engaged in various activities to increase public participation in the Company's IRP and CEIP processes. These specific actions, outreach methods and timing, and addressing barriers to participation and internal stakeholder development are discussed below.

Specific Actions

The Company has taken the following actions to promote equity and engagement within its Washington service area. These include:

Formed Equity Advisory Group (EAG): The EAG was assembled in 2021 to help inform and advise the Company on the issues most important to the communities that PacifiCorp serves in Washington. The EAG comprises nine representatives from highly impacted communities and vulnerable populations within the Company's Washington service area, including Yakima, Yakama Nation, and Walla Walla. These members have expertise on equity-related topics, such as the health of vulnerable populations and programs for low-income customers. The EAG meets regularly and provides significant input on the Company's CBIs, metrics included in the CEIP, and how the Company plans and operates within its Washington service area.

Development of CBIs: Consistent with CETA, the Company is committed to ensuring that the benefits from the transition to clean energy are broadly shared and equitably distributed among all customers, with a specific focus on named communities. PacifiCorp has partnered with stakeholders and advisory groups, including the EAG, to identify the highest priority benefits to customers and identify potential barriers and burdens that may prevent some customers from receiving those benefits. These efforts have resulted in nine CBIs and associated weighting factors to evaluate the equitable distribution of benefits. This allows the Company to assess and monitor the impacts of each proposed program, action, and investment. In addition, the CBIs were included in the Company's most recent CEIP to inform utility action, focusing on the named communities that were identified within the Company's Washington service area.

Established Utility Actions within the CEIP: PacifiCorp committed to and made several changes to residential and non-residential customer energy efficiency programs to increase the focus on delivery of benefits to named communities. These utility actions were informed on input received from the EAG and CBIs. The same utility actions will be included in the 2022-2023 Biennial Conservation Plan, and updates for 2023 will be included in the 2023 Annual Conservation Plan. These utility actions include modifications to the low-income weatherization program that the Company filed on December 21, 2021. These changes included, but were not limited to, expanding tariff applicability for the installation of energy efficiency improvements. Funds available for repairs were also increased from 15 percent to 30 percent of the annual reimbursement on energy efficient measures and income guidelines were updated to be consistent with RCW 19.405.020(25). Before these changes, some income-qualified homes could not receive energy efficiency improvements due to the extent of critical maintenance needed before the energy efficiency improvements could be made.

Establish an Electric Vehicle (EV) grant program: PacifiCorp established EV programs detailed in PacifiCorp's Washington Transportation Electrification Plan. On May 20, 2022, PacifiCorp filed its 2022 "Washington State Transportation Electrification Plan" with the Washington Utilities and Transportation Commission under Docket UE-220359[21]. PacifiCorp supplemented its original filing with an addendum filed on September 28, 2022. This is PacifiCorp's first filed TEP since enabling legislation was enacted in 2019. The Commission acknowledged the plan on October 27, 2022, enabling PacifiCorp to begin development of the proposed programs in the TEP inclusive of a communities grant program, outreach and education program, and managed charging pilot program. These programs would broaden the previous EV programs by allowing for multiple project types to participate with benefits and preference targeted towards named communities. The overall goal is to provide exploratory programs that will help to plan, promote, or deploy electric transportation technology and projects within Named Communities. Looking ahead, PacifiCorp is working with its Equity Advisory Group and the Washington Utility and Transportation Commission and other stakeholders to review draft program and pilot application prior to filing in Q2 of 2023. PacifiCorp anticipates launch of program and pilots in Q3 of 2023.

Modified the Low-Income Bill Assistance Program: PacifiCorp's low-income bill assistance (LIBA) program was established in 2003. LIBA provides a tiered discount based on income levels. Previously, LIBA was designed to provide credits to income-eligible households on monthly usage over 600 kWh and included an annual enrollment cap. Consistent with the requirements in RCW 19.505.120 and consultation with the Low-Income Advisory Group, the Company proposed modifications to its program. In particular, the Company proposed to (1) increase the maximum income threshold for the program consistent with RCW 19.405.020(25), (2) modify the discount from a per kWh above 600 kWh, to a percentage discount of the net bill, with the discount level based on household size and income; and (3) eliminate the annual enrollment cap. These changes were allowed to go into effect on August 1, 2021.

PacifiCorp also hired Empower Dataworks to prepare a 2022 Energy Burden Assessment (EBA) for the Company's residential customers in Washington. In the EBA, Empower Dataworks highlighted that the LIBA program design is very good at targeting benefits to higher burden customers and program administration. It also noted that the overhead costs are very efficient relative to other programs in the state, and praised the great coordination between PacifiCorp and the local community action agencies on providing culturally appropriate marketing and program designs. PacifiCorp partners with three

[21] Materials available online at UTC Case Docket Document Sets | UTC (wa.gov)

agencies to administer and deliver the program: Blue Mountain Action Council (BMAC) serves Columbia, Garfield, and Walla Walla counties, Opportunities Industrialization Center of Washington (OIC) serves Upper Yakima County, and Yakima Valley Farm Workers Clinic dba Northwest Community Action Center (NCAC) serves Lower Yakima County.

Continued and Expanded Outreach

To ensure consistent outreach, PacifiCorp continues to use all of the engagement methods included in its CEIP, including PacifiCorp's CEIP and IRP dedicated website; email updates; fact sheet and flyers; bill inserts and bill messages; interactive voice response; social media, paid and press media; text message notices; partner channels; community surveys; CEIP Public Meetings and Technical Conferences; EAG Meetings; existing advisory groups and EAG pre-meeting materials; and meeting summaries.

These engagement methods attempt to further facilitate durable community relationships. Examples of specific continued outreach include:

- PacifiCorp's Washington EAG began meeting in 2021 and has continued to hold meetings to, in part, support CEIP development and implementation. These meetings have continued into 2023, and have offer in-person and virtual meeting opportunities throughout the year;
- PacifiCorp's initial public participation outreach included both telephone and email and was designed to inform existing advisory groups (including the IRP Public Input Process) of the opportunity to provide feedback, as well as to form the Washington EAG;
- PacifiCorp continues to utilize its Washington Clean Energy Transformation Act & Equitable Distribution of Benefits webpage and the Integrated Resource Plan webpage to provide information to the public regarding how to participate in meetings, the development of the CEIP and the development of the IRP;
- PacifiCorp's outreach for both the DSM Advisory Group and the Low-Income Advisory Group continues to occur by email to participants on the distribution list; and
- The company has set up a dedicated email address, CEIP@pacificorp.com, that is posted on the webpage to facilitate timely responses to any stakeholder questions. Additionally, PacifiCorp encouraged members of the public who wanted to participate in the development of the CEIP to join the company's email list, which was used to communicate upcoming meetings, meeting materials, and other opportunities for education and feedback.

In addition to continued outreach, the Company has expanded its Public Participation outreach methods to draw in more diverse customer interests. For example:

- PacifiCorp developed a survey that targets our broader Washington customer base to gather input on the development of the CEIP. The survey was made available in English and Spanish between July 2, 2021, and August 10, 2021. There were separate versions for residential and non-residential customers. Survey results were prepared, summarized, and posted on the Washington Clean Energy Transformation Act & Equitable Distribution of

Benefits webpage. Customer feedback was incorporated into the Customer Benefit Indicator (CBI) weighting process. PacifiCorp continues to explore methods to improve these surveys, and plans to use similar outreach methods in 2023.
- PacifiCorp held 3 technical conferences on the CEIP development process that were targeted for parties interested in a deeper examination of the CEIP. PacifiCorp is open to additional CEIP technical conferences.

The Company welcomes continues to explore—and welcomes helpful suggestions—for expanded public participation methods for future CEIP planning cycles.

Addressing Barriers to Participation

The Company continues to address barriers to participation, and support inclusion and accessibility in the Company's CEIP and IRP planning processes. For example PacifiCorp:

- Now offers hybrid meeting formats for its EAG meetings, where members can attend meetings online or in-person. Initially, the COVID-19 pandemic prevented in-person gatherings from taking place, making virtual meetings necessary. Over time, the need for virtual meeting formats lessened, giving the group space to explore other ways to connect, and various stakeholders expressed an interest for in-person meeting options as well. PacifiCorp held its first hybrid meeting for the Washington EAG in March 2023. The majority of the participants attended in person. The company intends to continue to offer a mix of online and in-person meeting options in the future.
- Continues to offer Spanish translation of meeting materials, and have interpreters present at public participation meetings.
- Continues to seek input from the EAG and public to foster inclusion, equity, and continuing to learn about the ways that the company can better communicate to meet the cultural needs of its communities.
- Continuing to ensure that information is available in broadly understood terms for all in the community, and ensuring that customers have access to information through various accessible formats.
- Has continued engagement with its on-going EAG, and stakeholders interested in the CEIP development process.

These actions to address barriers to participation help PacifiCorp identify specific actions that support initiatives to improve health, safety, and well-being of its communities, and PacifiCorp continues its CEIP public participation process to ensure open, transparent, and accessible processes.

Internal Stakeholder Development

PacifiCorp is also making efforts to promote equity through internal stakeholder development. To achieve results in this arena, PacifiCorp is developing and equipping internal stakeholders with adaptive leadership skills, education to build intercultural competency, and access to a devoted core team supporting an equity lens on stakeholder engagement. This has included:

- **Outside subject matter expertise and facilitation**. The Company has engaged E Source as its stakeholder facilitator and content support developer, who acts as an accountability partner for internal stakeholder development. This accountability allows a value chain that creates and strengthens our internal equity decision-making lens and ensures that it bears fruit in our deliverables and stakeholder engagement, and this consequently will help achieve equitable results in the communities the Company serves.

- **Building adaptive leadership skills**. The Company held an adaptive leadership in equity workshop for key PacifiCorp employees who work on external engagement and customer and community solutions. This workshop was held in December 2022 and focused on acknowledging and finding agreement on the value of building a safe and supportive space to grow individual's adaptive leadership skills and provide tools, resources, and guidance in our shared journey. This workshop is important because developing an equity decision-making lens requires understanding and acceptance on the individual and corporate level of intercultural competency. Further, it requires a commitment to self-awareness, learning, application (success and lessons learned), and growth.

- **Building intercultural communication skills**. The Company plans to host an internal workshop in the spring of 2023, that will equip its employees with the tools necessary for effective intercultural communication. While it is expected that most subscribe to the Golden Rule – do unto others as you would like done unto you – in communications, this stops short of intercultural competency. The golden rule is based on a monocultural worldview and assumes all groups value the same thing. This workshop aims to support trust building and the adaption of individual perspective and behaviors to connect better, communicate and engage others.

- **Benchmarking and building intercultural competency.** The Company will administer the Intercultural Development Inventory (IDI) Survey, considered an international benchmark, in the fall of 2023. Core team members will be debriefed privately on their scores and given individual development and coaching plans

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 = international organization for standardization / 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

LRA = Local Regulatory Authority

LSE = load serving entities

MATS = Mercury and Air Toxics Standards

MEHC = MidAmerican Energy Holdings Company

MMBpd = Million barrels of oil per day

MMBtu = Million British thermal units

MSP = Balancing Authority Area / 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

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 / Operations Mapping 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) / Rural Electric Cooperative

RFI = request for information

RFM = Rate Forecasting Model

RFP = Request for Proposal

RH = Relative humidity

RICE = Reciprocating Internal Combustion Engine

RMP = Rocky Mountain Power / Resource Management Plan

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 / Sarbanes-Oxley Act

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

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