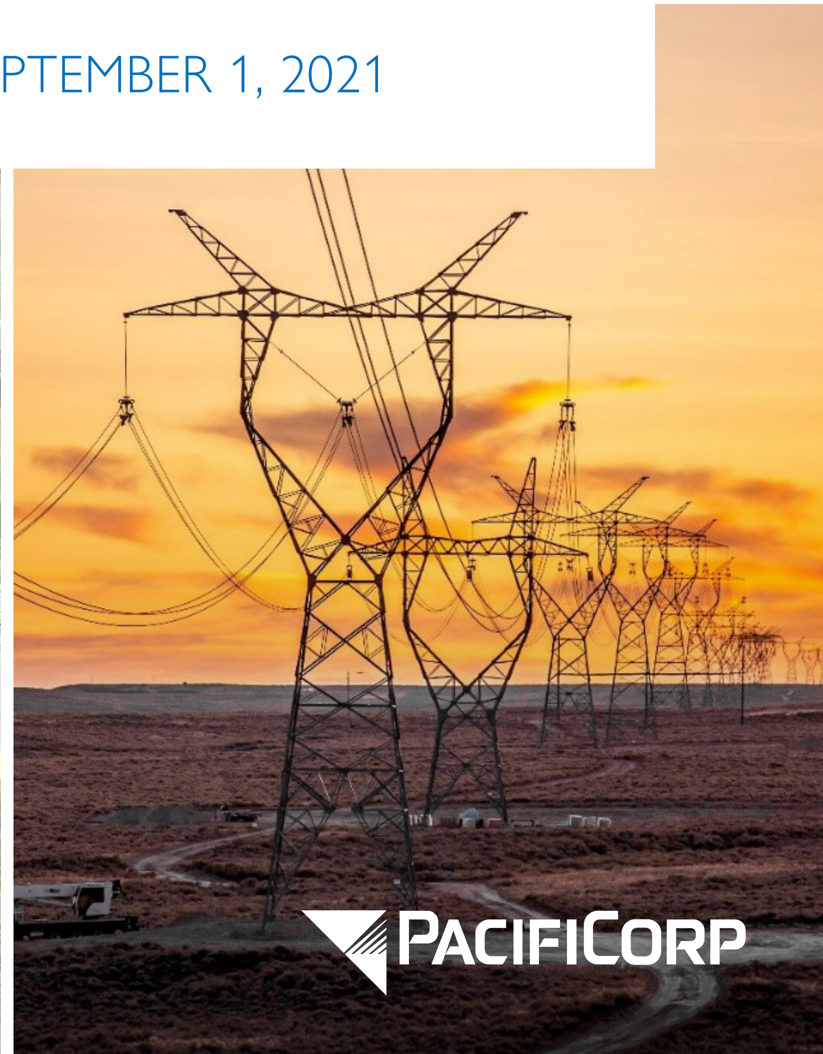
2021 Integrated Resource Plan

VOLUME II | SEPTEMBER 1, 2021



PACIFICORP

This 2021 Integrated Resource Plan Report is based upon the best available information at the time of preparation. The IRP action plan will be implemented as described herein, but is subject to change as new information becomes available or as circumstances change. It is PacifiCorp's intention to revisit and refresh the IRP action plan no less frequently than annually. Any refreshed IRP action plan will be submitted to the State Commissions for their information.

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Cover Photos (Top to Bottom):
Pavant III Solar Plant
Marengo Wind Project
Transmission Line - Wyoming
Panguitch Solar & Battery Storage

APPENDIX A – LOAD FORECAST DETAILS

Introduction

This appendix reviews the load forecast used in the modeling and analysis of the 2021 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 June 2020. The compound annual load growth rate for the 10-year period (2021 through 2030) is 1.31 percent. Relative to the load forecast prepared for the 2019 IRP, PacifiCorp's 2030 forecast load requirement decreased in all jurisdictions other than Utah and California, while PacifiCorp system load requirement increased approximately 2.06 percent. Figure A.1 has a comparison of the load forecasts from the 2021 IRP to the 2019 IRP.

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

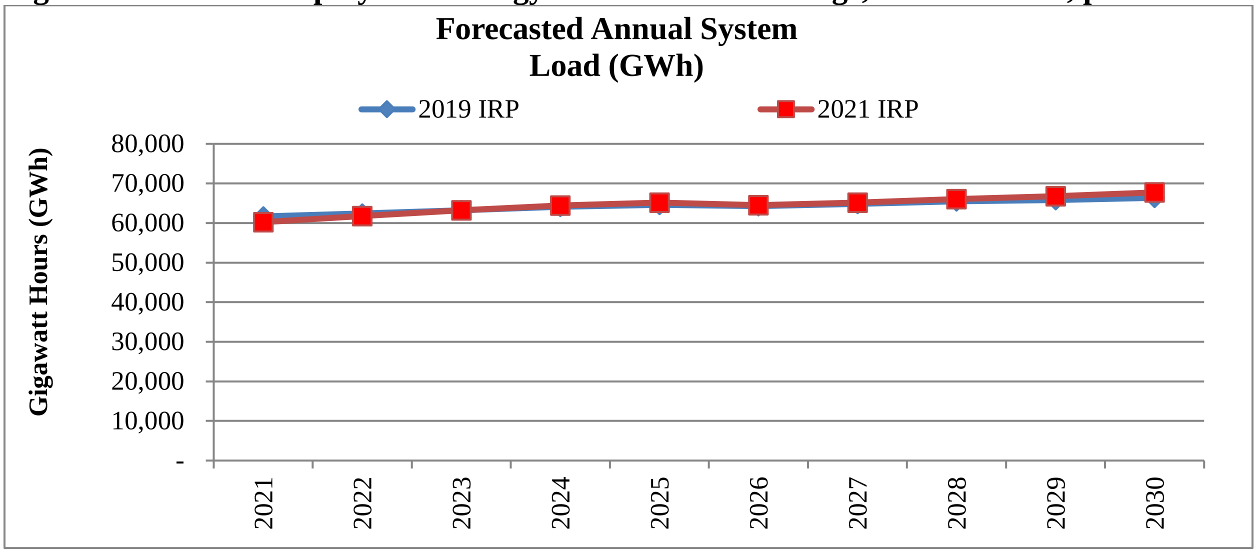


Table A.1 and Table A.2 show the annual load and coincident peak load forecast when not reducing load projections to account for new energy efficiency measures (Class 2 DSM).[1] Tables A.3 and A.4 show the forecast changes relative to the 2019 IRP load forecast for loads and coincident system peak, respectively.

Table A.1 – Forecasted Annual Load, 2021 through 2030 (Megawatt-hours), at Generation, pre-DSM

Year	Total	OR	WA	CA	UT	WY	ID
2021	60,221,570	15,052,100	4,508,140	873,350	26,683,220	9,151,270	3,953,490
2022	61,760,910	15,406,270	4,591,020	879,260	27,444,090	9,467,940	3,972,330
2023	63,242,990	15,758,680	4,656,030	882,500	28,210,380	9,756,470	3,978,930
2024	64,451,310	16,106,120	4,710,640	888,170	28,792,180	9,963,260	3,990,940
2025	65,162,260	16,239,510	4,730,240	888,890	29,341,030	9,957,000	4,005,590
2026	64,527,030	16,418,820	4,760,890	891,130	28,352,920	10,079,510	4,023,760
2027	65,178,400	16,609,250	4,796,190	892,410	28,700,930	10,140,050	4,039,570
2028	66,083,420	16,856,640	4,850,400	896,280	29,192,860	10,227,820	4,059,420
2029	66,768,660	17,037,100	4,879,900	895,370	29,609,850	10,278,220	4,068,220
2030	67,723,210	17,268,040	4,923,100	898,610	30,155,750	10,393,670	4,084,040
Compound Annual Growth Rate							
2021-30	**1.31%**	**1.54%**	**0.98%**	**0.32%**	**1.37%**	**1.42%**	**0.36%**

[1] Class 2 DSM 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
2021	10,374	2,421	768	140	5,054	1,223	768
2022	10,535	2,442	779	140	5,158	1,247	768
2023	10,691	2,462	788	142	5,255	1,280	765
2024	10,808	2,480	795	141	5,326	1,300	765
2025	10,942	2,500	804	142	5,419	1,302	775
2026	10,867	2,513	810	142	5,308	1,314	779
2027	10,940	2,527	816	142	5,351	1,321	782
2028	11,043	2,540	823	143	5,426	1,329	783
2029	11,133	2,551	831	142	5,490	1,335	784
2030	11,238	2,562	837	142	5,563	1,348	786
Compound Annual Growth Rate							
2021-30	**0.89%**	**0.63%**	**0.96%**	**0.19%**	**1.07%**	**1.09%**	**0.25%**

Table A.3 – Annual Load Change: June 2020 Forecast less September 2018 Forecast (Megawatt-hours) at Generation, pre-DSM

Year	Total	OR	WA	CA	UT	WY	ID
2021	(1,446,650)	(710,630)	(188,810)	(12,870)	193,120	(693,260)	(34,200)
2022	(669,210)	(667,350)	(133,820)	(4,040)	554,880	(383,170)	(35,710)
2023	53,140	(467,730)	(100,410)	650	851,120	(178,640)	(51,850)
2024	352,250	(316,440)	(92,170)	5,990	915,480	(94,950)	(65,660)
2025	600,950	(283,400)	(91,260)	11,470	1,120,660	(95,750)	(60,770)
2026	291,170	(250,470)	(94,560)	17,670	705,630	(31,000)	(56,100)
2027	351,380	(211,750)	(96,000)	24,810	756,540	(70,940)	(51,280)
2028	639,990	(160,230)	(94,050)	32,590	937,330	(32,350)	(43,300)
2029	926,340	(91,430)	(91,890)	40,000	1,125,640	(21,450)	(34,530)
2030	1,368,710	18,030	(84,790)	49,670	1,407,610	530	(22,340)

Table A.4 – Annual Coincident Peak Change: June 2020 Forecast less September 2018 Forecast (Megawatts) at Generation, pre-DSM

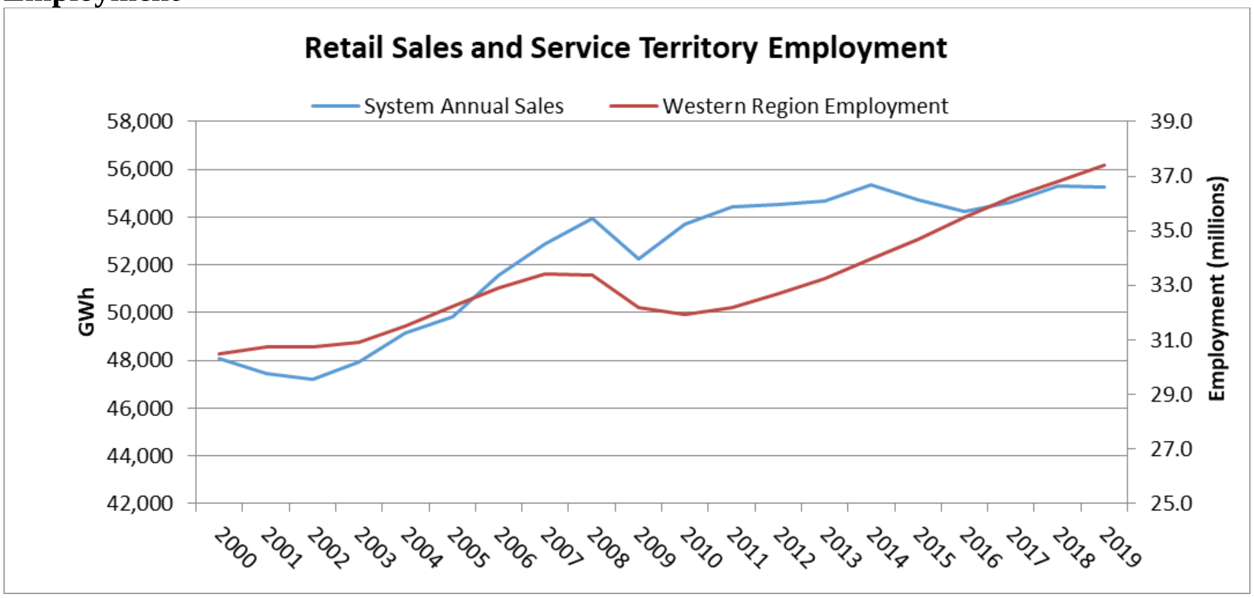
Year	Total	OR	WA	CA	UT	WY	ID
2021	17	(71)	(11)	(5)	192	(68)	(20)
2022	67	(84)	(6)	(4)	230	(46)	(23)
2023	111	(81)	(4)	(4)	250	(22)	(29)
2024	121	(75)	7	0	238	(25)	(26)
2025	157	(80)	(5)	(1)	264	(13)	(8)
2026	49	(82)	(5)	(0)	165	(7)	(20)
2027	45	(85)	(6)	2	165	(11)	(18)
2028	58	(89)	(6)	3	175	(8)	(16)
2029	70	(92)	(6)	5	183	(7)	(12)
2030	98	(89)	(6)	7	199	(4)	(9)

Load Forecast Assumptions

Regional Economy by Jurisdiction

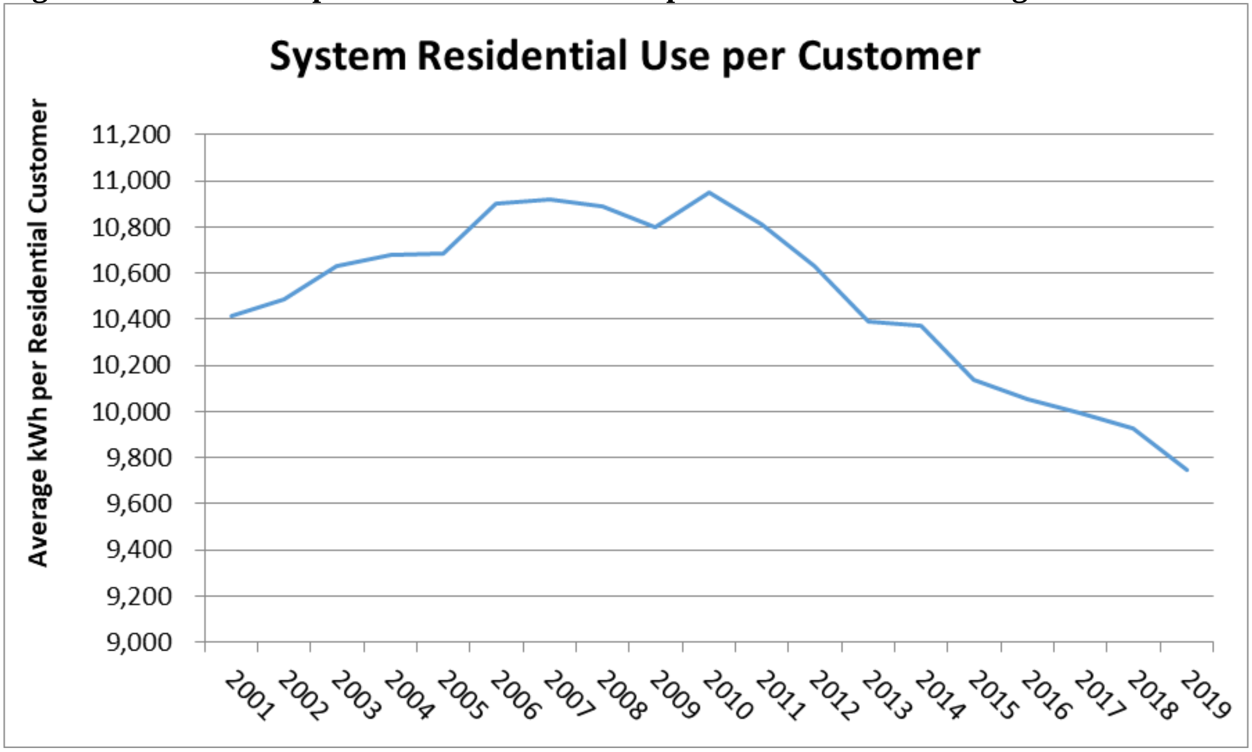
The PacifiCorp electric service territory is comprised of six states and within these states the company serves customers in a total of 90 counties. The level of retail sales for each state and county is correlated with economic conditions and population statistics in each state. PacifiCorp uses both 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 2019, 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 2008-2009 recession.

Figure A.2 – PacifiCorp Annual Retail Sales 2000 through 2019 and Western Region Employment



The 2021 IRP forecast utilizes the October 2019 release of IHS Markit economic driver forecast; whereas the 2019 IRP relies on the September 2018 release from IHS Markit. Figure A.3 shows the weather normalized average system residential use per customer.

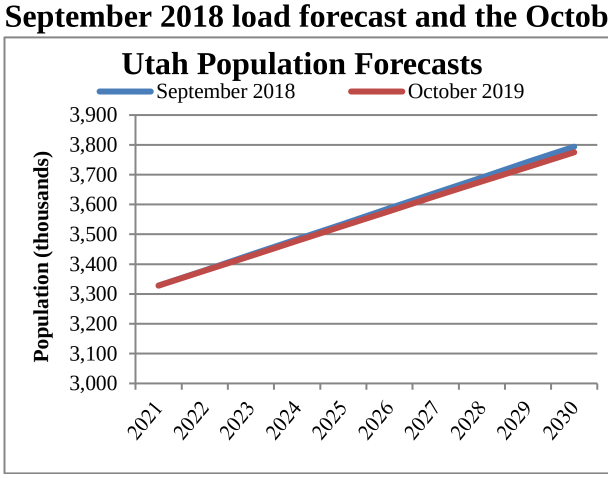
Figure A.3 – PacifiCorp Annual Residential Use per Customer 2001 through 2019

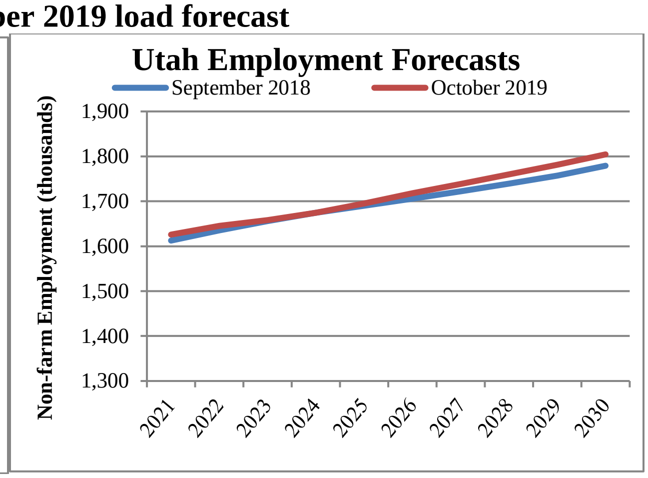


Utah

PacifiCorp serves 26 of the 29 counties in the state of Utah, with Salt Lake City being the largest metropolitan area served by the Company within the state. Utah is expected to experience an annual increase of 1.16 percent in non-farm employment over the next 10 years. Figure A.4 shows the change in population and employment forecasts between the 2021 IRP relative to the 2019 IRP forecast. This figure illustrates that the population forecast is relatively unchanged, but slightly lower. The employment forecast is also relatively unchanged, but slightly higher over the 2021 through 2030 timeframe.

Figure A.4 – IHS Global Insight Utah Population and Employment Forecasts from the September 2018 load forecast and the October 2019 load forecast

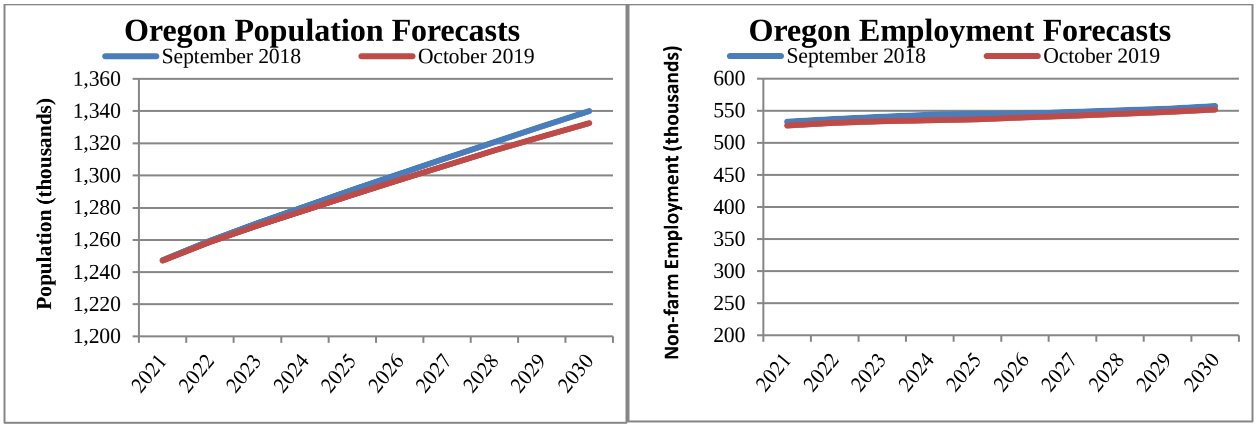




Oregon

PacifiCorp serves 25 of the 36 counties in Oregon, but provided only 26.2 percent of electric retail sales in the state of Oregon in 2018.[2] Figure A.5 shows the change in population and employment forecasts for the 2021 IRP relative to the 2019 IRP forecast. This figure illustrates that the Oregon population and employment forecasts have remained relatively unchanged, but have decreased slightly.

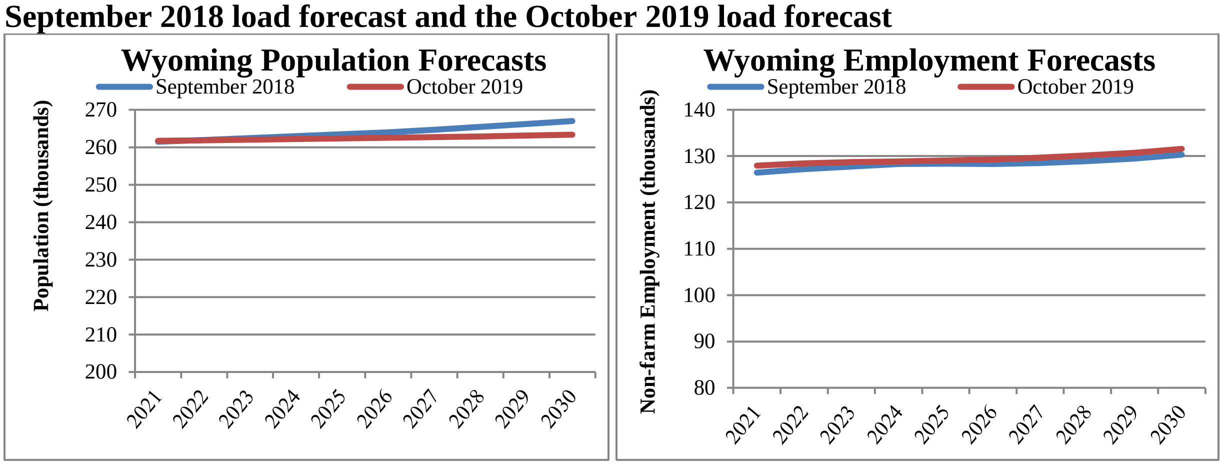
Figure A.5 - IHS Global Insight Oregon Population and Employment forecasts from the September 2018 load forecast and the October 2019 load forecast



Wyoming

The Company serves 15 of the 23 counties in Wyoming, with Casper being the largest metropolitan area served by the Company in the state. Industrial sales make up approximately 74% of the Company's Wyoming sales. Figure A.6 shows the change in population and employment forecasts for the 2021 IRP relative to the 2019 IRP forecast. This figure illustrates that the Wyoming population and employment forecasts used in the 2021 IRP forecast has remained relatively unchanged to the 2019 IRP.

Figure A.6 - IHS Global Insight Wyoming Population and Employment forecasts from the September 2018 load forecast and the October 2019 load forecast

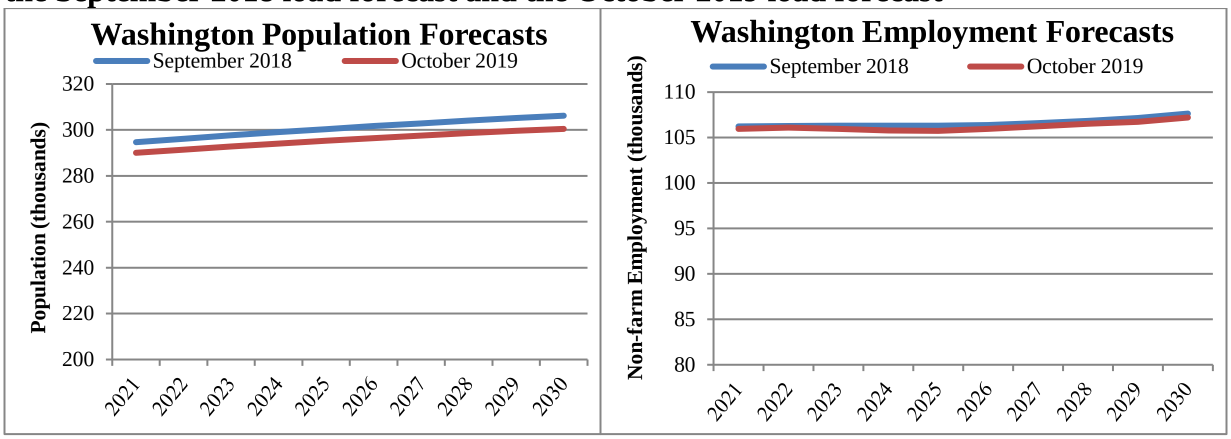


[2] Source: Oregon Public Utility Commission, 2018 Oregon Utility Statistics.

Washington

PacifiCorp serves the following counties in Washington state: Benton, Columbia, Cowlitz, Garfield, Walla Walla, and Yakima. Yakima is the most populated county that the Company serves in Washington State and has a large concentration of agriculture and food processing businesses. Residential and commercial sales are roughly equal in size each making up approximately 39 percent of the Company's Washington sales. Figure A.7 shows the change in population and employment forecasts for the 2021 IRP relative to the 2019 IRP forecast. This figure illustrates that the population forecast is lower, while the employment forecast is unchanged.

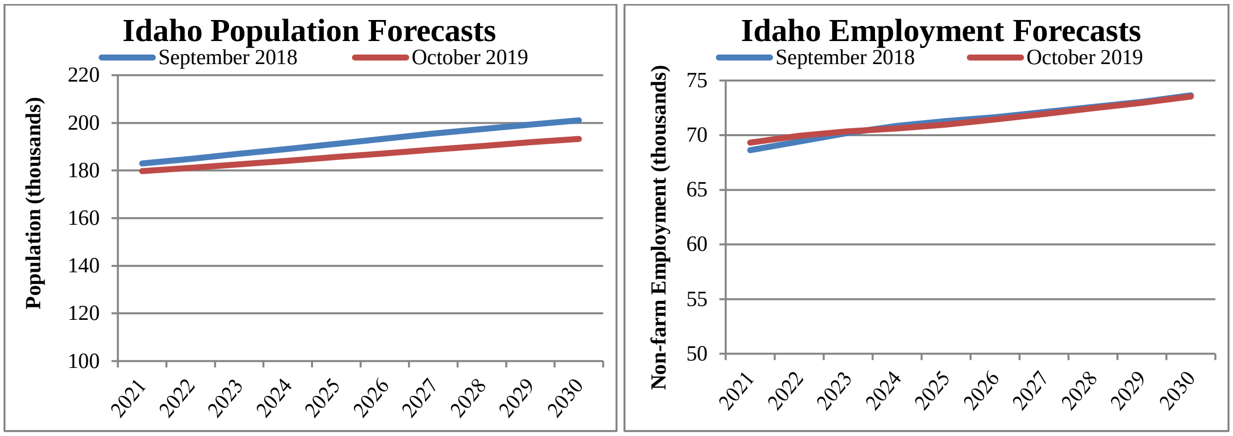
Figure A.7 – IHS Global Insight Washington Population and Employment forecasts from the September 2018 load forecast and the October 2019 load forecast



Idaho

The Company serves 14 of the 44 counties in the state of Idaho, with the majority of the Company's service territory in rural Idaho. Industrial sales make up approximately 47% of the Company's Idaho sales. Figure A.8 shows the change in population and employment forecasts for the 2021 IRP relative to the 2019 IRP forecast. This figure illustrates that the forecast for population has decreased, while the employment forecast has remained consistent over the 2021 to 2030 timeframe.

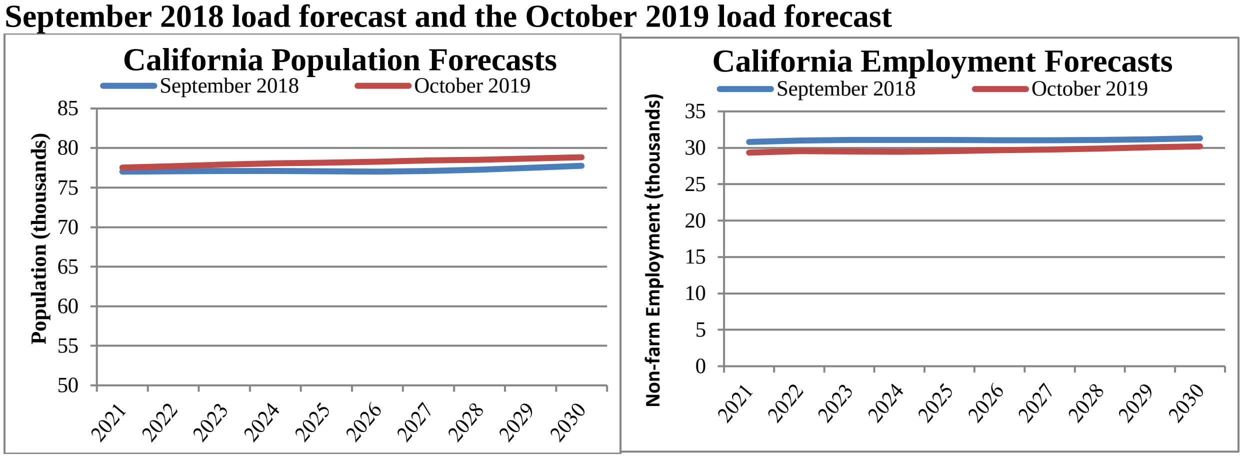
Figure A.8 – IHS Global Insight Idaho Population and Employment forecasts from the September 2018 load forecast and the October 2019 load forecast



California

The four northern California counties served by PacifiCorp are largely rural, which include Del Norte, Modoc, Shasta and Siskiyou Counties. Crescent City is the largest metropolitan area served by the Company in California. Residential sales make up approximately 48 percent of the Company's California sales. Figure A.9 shows the change in population and employment forecasts for the 2021 IRP relative to the 2019 IRP forecast. This figure illustrates that the population forecast has increased, while the employment forecast has decreased.

Figure A.9 – IHS Global Insight California Population and Employment forecasts from the September 2018 load forecast and the October 2019 load forecast

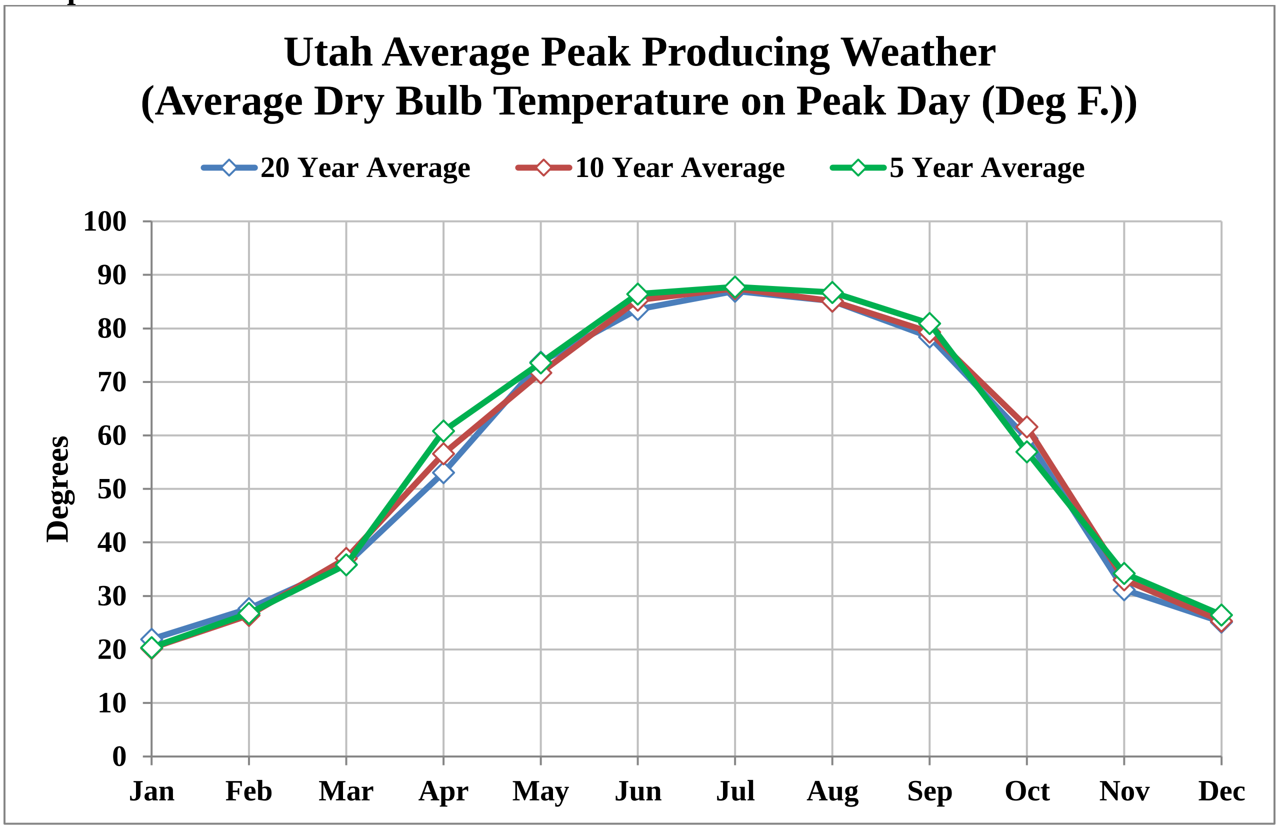


Weather

The Company's load forecast is based on normal weather defined by the 20-year time period of 2000-2019. The Company updated its temperature spline models to the five-year time period of October 2014 – September 2019. The Company's spline models are used to model the commercial and residential class temperature sensitivity at varying temperatures.

The Company has reviewed the appropriateness of using the average weather from a shorter time period as its "normal" peak weather. Figure A.10 indicates that peak producing weather does not change significantly when comparing five, 10, or 20-year average weather.

Figure A.10 – 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 January 2020. The historical data period used to develop the industrial monthly sales forecast is from January 2000 through January 2020 in Utah, Wyoming, and Washington, January 2002 through January 2020 in Idaho, and January 2003 through January 2020 in California and January 2008 through January 2020 in Oregon.

The following tables are the annual actual retail sales, non-coincident peak, and coincident peak by state used in calculating the 2021 IRP retail sales forecast.

Table A.5 – Weather Normalized Jurisdictional Retail Sales 2000 through 2019

System Retail Sales - Megawatt-hours (MWh)*							
Year	California	Idaho	Oregon	Utah	Washington	Wyoming	**System**
2000	775,192	3,089,288	13,955,787	18,744,308	4,105,482	7,414,678	**48,084,734**
2001	776,422	2,980,497	13,516,606	18,504,774	4,021,390	7,668,756	**47,468,446**
2002	799,842	3,230,347	13,099,087	18,604,385	4,018,756	7,445,204	**47,197,621**
2003	815,011	3,247,459	13,085,666	19,273,299	4,073,691	7,440,948	**47,936,073**
2004	844,695	3,308,170	13,199,227	19,866,036	4,104,202	7,804,357	**49,126,687**
2005	835,299	3,261,932	13,201,375	20,282,194	4,216,649	8,006,549	**49,803,998**
2006	858,510	3,340,635	13,915,186	21,098,318	4,135,813	8,220,696	**51,569,159**
2007	874,531	3,408,616	14,021,185	21,999,896	4,080,890	8,517,002	**52,902,119**
2008	866,199	3,420,524	13,780,706	22,599,294	4,077,495	9,216,788	**53,961,007**
2009	829,274	2,954,023	13,113,340	22,024,520	4,060,707	9,269,845	**52,251,710**
2010	841,107	3,439,999	13,177,771	22,508,996	4,055,511	9,664,424	**53,687,809**
2011	803,543	3,464,119	13,032,607	23,295,557	4,023,385	9,809,825	**54,429,035**
2012	785,008	3,515,467	13,043,196	23,640,249	4,051,450	9,487,492	**54,522,863**
2013	775,368	3,558,468	13,087,558	23,643,822	4,068,821	9,551,446	**54,685,482**
2014	775,046	3,548,642	13,152,703	24,147,318	4,117,170	9,602,358	**55,343,237**
2015	746,165	3,506,314	13,117,689	23,873,791	4,111,291	9,374,355	**54,729,605**
2016	755,863	3,467,134	13,216,931	23,535,056	4,055,967	9,207,677	**54,238,627**
2017	760,480	3,580,973	13,164,823	23,661,450	4,088,797	9,351,510	**54,608,034**
2018	742,614	3,614,740	13,104,102	24,528,017	4,069,834	9,258,202	**55,317,509**
2019	744,447	3,504,257	13,168,919	24,435,035	4,059,165	9,333,539	**55,245,362**
Compound Annual Growth Rate							
2000-19	**-0.21%**	**0.67%**	**-0.30%**	**1.41%**	**-0.06%**	**1.22%**	**0.73%**

*System retail sales do not include sales for resale

Table A.6 – Non-Coincident Jurisdictional Peak 2000 through 2019

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	5,163	895	1,363	**10,997**
Compound Annual Growth Rate							
2000-19	**-0.79%**	**0.77%**	**0.06%**	**1.79%**	**0.69%**	**1.33%**	**1.06%**

*Non-coincident peaks do not include sales for resale

Table A.7 – Jurisdictional Contribution to Coincident Peak 2000 through 2019

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**
Compound Annual Growth Rate							
2000-19	**-1.20%**	**1.77%**	**-0.16%**	**1.79%**	**0.04%**	**1.29%**	**1.05%**

*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, 2019.

Forecast Methodology Overview

Class 2 Demand-side Management Resources in the Load Forecast

PacifiCorp modeled Class 2 DSM 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 Class 2 DSM; Plexos then determines the amount of Class 2 DSM—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 Class 2 DSM supply curves, along with the economic screening provided by Plexos, determines the cost-effective mix of Class 2 DSM 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 January 2020. 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 average monthly historical peak-producing weather for the 20-year period, 2000 through 2019. 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 as identified above, 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.

COVID-19 Adjustments

For the 2021 IRP, the Company incorporated the expected impacts of COVID-19 on forecasted electricity demand. These impacts include stay-at-home impacts, longer-term economic impacts and commodity price impacts.

Stay-at-home impacts were assumed to last over the March 2020 through June 2020 timeframe. Stay-at-home period impacts were based on observed class level load impacts over the March through April 2020 timeframe. Longer-term COVID-19 impacts based on IHS Markit economic driver data released March 2020 was incorporated into the forecast. The Wyoming industrial class forecast was adjusted to account for COVID-19 commodity price impacts based on observed load changes, commodity price projections, and Regional Business Manager input. Commodity price impacts were projected to last from March 2020 through June 2023 timeframe and are expected to improve over the period.

Electrification Adjustments

The load forecast used for 2021 IRP portfolio development includes the Company's expectations for transportation electrification based on current and expected electric-vehicle adoption trends. These projections were incorporated as a post-model adjustment to the residential and commercial sales forecasts. The load forecast also incorporates the Company's expectations for building electrification initiatives. Given the status of building electrification initiatives in PacifiCorp's service territory, only the expected impact of these programs for Utah have been incorporated into the sales forecast.

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.8 – System Annual Retail Sales Forecast 2021 through 2030, post-DSM

System Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2021	16,389,484	18,613,139	18,287,179	1,441,875	107,253	**54,838,930**
2022	16,384,868	19,324,611	18,589,219	1,415,430	98,411	**55,812,538**
2023	16,439,913	19,905,826	18,898,932	1,398,288	91,221	**56,734,180**
2024	16,589,964	20,276,728	19,037,799	1,385,557	85,970	**57,376,018**
2025	16,654,511	20,413,589	19,030,766	1,376,104	81,656	**57,556,626**
2026	16,825,236	20,444,277	17,767,848	1,369,039	78,667	**56,485,067**
2027	16,999,818	20,438,006	17,824,694	1,356,979	76,390	**56,695,887**
2028	17,265,999	20,525,328	17,905,345	1,340,301	74,749	**57,111,722**
2029	17,418,800	20,482,093	17,921,770	1,321,831	72,892	**57,217,386**
2030	17,613,925	20,436,176	18,102,483	1,298,520	71,383	**57,522,487**
Compound Annual Growth Rate						
2021-30	0.80%	1.04%	-0.11%	-1.16%	-4.42%	**0.53%**

Residential

The average annual growth of the residential class sales forecast increased from -0.29 percent in the 2019 IRP to 0.80 percent in the 2021 IRP. The number of residential customers across PacifiCorp's system is expected to grow at an annual average rate of 1.22 percent, reaching approximately 1.93 million customers in 2030, with Rocky Mountain Power states adding 1.49 percent per year and Pacific Power states adding 0.80 percent per year.

Commercial

Average annual growth of the commercial class sales forecast increased from 0.87 percent annual average growth in the 2019 IRP to 1.04 percent in the 2021 IRP. The number of commercial customers across PacifiCorp's system is expected to grow at an annual average rate of 0.99 percent, reaching approximately 240,000 customers in 2030, with Rocky Mountain Power states adding 1.23 percent per year and Pacific Power states adding 0.66 percent per year.

Industrial

Average annual growth of the industrial class sales forecast increased from -0.52 percent annual average growth in the 2019 IRP to -0.11 percent expected annual growth in the 2021 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.9 – Forecasted Retail Sales Growth in Oregon, post-DSM summarizes Oregon state forecasted retail sales growth by customer class.

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

Oregon Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2021	5,708,962	5,767,210	1,491,973	312,674	34,484	**13,315,304**
2022	5,733,105	5,954,746	1,487,633	291,620	32,284	**13,499,389**
2023	5,754,277	6,145,533	1,485,094	280,748	30,277	**13,695,929**
2024	5,812,675	6,293,686	1,487,735	275,951	28,624	**13,898,671**
2025	5,841,879	6,290,798	1,482,175	275,724	27,104	**13,917,680**
2026	5,895,695	6,298,198	1,479,349	278,168	25,962	**13,977,372**
2027	5,957,709	6,306,969	1,475,887	280,047	25,082	**14,045,694**
2028	6,048,834	6,330,610	1,475,301	279,611	24,491	**14,158,847**
2029	6,112,862	6,328,312	1,465,503	278,532	23,929	**14,209,138**
2030	6,204,688	6,337,488	1,459,048	275,343	23,572	**14,300,139**
Compound Annual Growth Rate						
2021-30	**0.93%**	**1.05%**	**-0.25%**	**-1.40%**	**-4.14%**	**0.80%**

Washington

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

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

Washington Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2021	1,571,875	1,526,929	746,477	156,438	5,334	**4,007,054**
2022	1,560,893	1,581,253	748,392	155,784	4,806	**4,051,128**
2023	1,557,071	1,610,608	749,236	155,057	4,621	**4,076,594**
2024	1,561,217	1,621,511	752,126	152,198	4,577	**4,091,630**
2025	1,552,484	1,611,943	750,699	149,416	4,545	**4,069,088**
2026	1,546,197	1,604,724	750,620	146,710	4,540	**4,052,790**
2027	1,538,962	1,601,382	748,971	143,453	4,538	**4,037,306**
2028	1,538,642	1,607,169	748,585	140,015	4,551	**4,038,963**
2029	1,529,991	1,602,860	745,385	136,236	4,537	**4,019,009**
2030	1,528,793	1,596,229	751,976	132,505	4,537	**4,014,041**
Compound Annual Growth Rate						
2021-30	**-0.31%**	**0.49%**	**0.08%**	**-1.83%**	**-1.78%**	**0.02%**

California

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

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

California Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2021	375,063	236,324	53,093	89,705	1,428	**755,613**
2022	375,655	237,999	54,023	89,502	1,300	**758,478**
2023	376,478	239,115	53,642	89,408	1,190	**759,834**
2024	378,596	240,418	53,510	89,397	1,102	**763,023**
2025	378,233	240,052	52,933	89,382	1,027	**761,626**
2026	379,038	239,998	52,015	89,250	971	**761,272**
2027	379,772	239,453	50,400	89,020	929	**759,574**
2028	381,554	239,392	48,763	88,708	900	**759,319**
2029	380,801	237,792	46,909	88,360	875	**754,736**
2030	381,404	236,731	47,316	88,038	859	**754,348**
Compound Annual Growth Rate						
2021-30	**0.19%**	**0.02%**	**-1.27%**	**-0.21%**	**-5.49%**	**-0.02%**

Utah

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

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

Utah Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2021	7,053,764	9,280,716	7,951,967	221,290	51,501	**24,559,238**
2022	7,067,147	9,707,481	8,002,444	216,942	45,608	**25,039,622**
2023	7,119,606	10,048,998	8,092,662	211,493	40,843	**25,513,603**
2024	7,213,987	10,280,843	8,077,013	206,050	37,505	**25,815,398**
2025	7,280,042	10,478,187	8,091,621	199,545	35,095	**26,084,490**
2026	7,416,655	10,562,626	6,729,247	193,084	33,644	**24,935,256**
2027	7,551,739	10,608,971	6,752,477	183,304	32,760	**25,129,251**
2028	7,734,200	10,718,474	6,783,092	171,698	32,328	**25,439,792**
2029	7,852,413	10,741,666	6,785,091	159,400	31,925	**25,570,495**
2030	7,977,046	10,753,325	6,871,983	144,262	31,745	**25,778,360**
Compound Annual Growth Rate						
2021-30	**1.38%**	**1.65%**	**-1.61%**	**-4.64%**	**-5.23%**	**0.54%**

Idaho

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

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

Idaho Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2021	707,725	498,044	1,785,159	636,507	2,557	**3,629,993**
2022	696,381	512,893	1,787,439	636,356	2,506	**3,635,575**
2023	695,209	522,820	1,773,920	636,379	2,453	**3,630,781**
2024	703,628	528,557	1,760,259	636,762	2,406	**3,631,612**
2025	706,280	527,074	1,758,834	636,846	2,344	**3,631,379**
2026	710,983	525,924	1,757,288	636,646	2,289	**3,633,130**
2027	715,049	524,117	1,753,296	636,000	2,234	**3,630,697**
2028	721,463	524,558	1,748,147	635,141	2,187	**3,631,496**
2029	721,451	520,988	1,741,166	634,212	2,128	**3,619,945**
2030	720,891	518,341	1,739,423	633,313	2,078	**3,614,045**
Compound Annual Growth Rate						
2021-30	**0.21%**	**0.44%**	**-0.29%**	**-0.06%**	**-2.28%**	**-0.05%**

Wyoming

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

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

Wyoming Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2021	972,095	1,303,915	6,258,509	25,261	11,950	**8,571,729**
2022	951,688	1,330,238	6,509,288	25,226	11,907	**8,828,346**
2023	937,271	1,338,751	6,744,378	25,202	11,836	**9,057,438**
2024	919,862	1,311,712	6,907,156	25,198	11,756	**9,175,684**
2025	895,593	1,265,534	6,894,504	25,191	11,541	**9,092,363**
2026	876,667	1,212,808	6,999,330	25,181	11,262	**9,125,247**
2027	856,587	1,157,113	7,043,662	25,156	10,846	**9,093,365**
2028	841,305	1,105,125	7,101,457	25,127	10,292	**9,083,306**
2029	821,282	1,050,476	7,137,716	25,091	9,497	**9,044,063**
2030	801,102	994,062	7,232,736	25,060	8,593	**9,061,553**
Compound Annual Growth Rate						
2019-28	**-2.13%**	**-2.97%**	**1.62%**	**-0.09%**	**-3.60%**	**0.62%**

Alternative Load Forecast Scenarios

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

The June 2020 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.

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 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 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 climate change scenario relies on 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).[3] The Company determined daily average temperatures and peak producing temperatures that correspond to the midpoint of the projected temperature increase ranges in the study. The Company used those temperatures to project the jurisdictional energy and jurisdictional peaks in the scenario.

Table A.15 – Projected Range of Temperature Change in the 2020s and 2050s relative to the 1990s below provides the projected range of temperature change for select sites within PacifiCorp's service territory, which were ultimately used to model projected temperatures in the 2021 IRP climate change scenario.

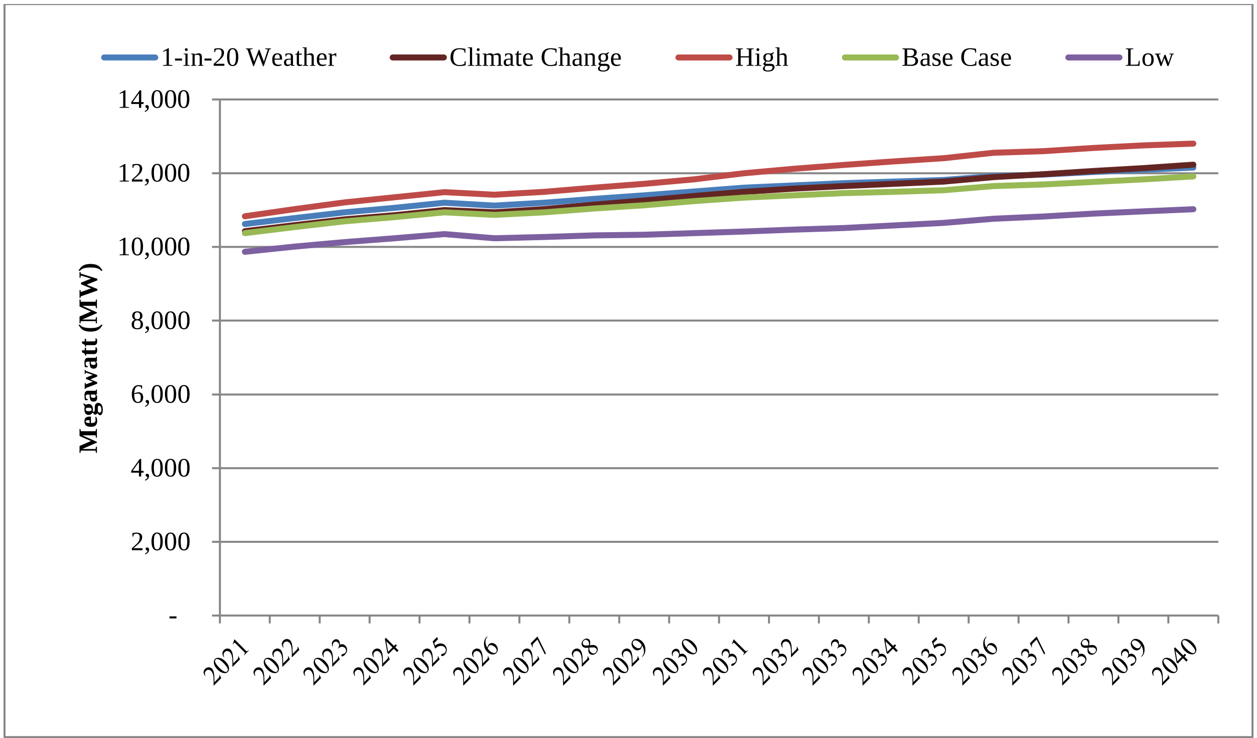
[3] United States Bureau of Reclamation, March 2016, Managing Water in the West, Technical Memorandum No. 86-68210-2016-01, West-Wide Climate Risk Assessments: Hydroclimate Projections. https://www.usbr.gov/climate/secure/docs/2016secure/wwcra-hydroclimateprojections.pdf

Table A.15 – Projected Range of Temperature Change in the 2020s and 2050s relative to the 1990s[4]

Bureau of Reclamation Site	PacifiCorp Jurisdiction Assumption	Projected Range of Temperature Change (°F)	
		2020s	2050s
Klamath River near Klamath	California	1.4 to 2.4	2.6 to 4.4
Snake River Near Heise	Idaho	1.6 to 3.1	3.1 to 5.6
Klamath River near Seiad Valley	Oregon	1.4 to 2.5	2.7 to 4.5
Green River near Greendale	Utah	1.7 to 3.1	3.1 to 5.7
Yakima River at Parker	Washington	1.5 to 2.6	2.7 to 5.0
Green River near Greendale	Wyoming	1.7 to 3.1	3.1 to 5.7

Figure A.11 shows the comparison of the above scenarios relative to the Base Case scenario.

Figure A.11 – Load Forecast Scenarios for 1-in-20 Weather, Climate Change, High, Base Case and Low, pre-DSM



[4] United States Bureau of Reclamation, March 2016, Managing Water in the West, Technical Memorandum No. 86-68210-2016-01, West-Wide Climate Risk Assessments: Hydroclimate Projections. https://www.usbr.gov/climate/secure/docs/2016secure/wwcra-hydroclimateprojections.pdf

APPENDIX B - IRP REGULATORY COMPLIANCE

Introduction

This appendix describes how PacifiCorp's 2021 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 2019 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 2019 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 also 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 Approach) 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 Approach.

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 2019 IRP.

The 2021 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.

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.

Idaho

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

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

This IRP is submitted to the Idaho PUC as the Resource Management Report for 2021, 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[34]). Consistent with the earlier guidelines (Order 89-507), the Oregon PUC notes that acknowledgment does not guarantee favorable ratemaking

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

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 least cost planning (Washington Administrative Code 480-100-238) (as amended, January 2006). In addition to a least cost plan, the rule requires provision of a two-year action plan and a progress report that "relates the new plan to the previously filed plan."

The rule requires PacifiCorp to submit a work plan for informal commission review not later than 12 months prior to the due date of the plan. The work plan is required to lay out the contents of the IRP, the resource assessment method, and timing and extent of public participation. PacifiCorp filed a work plan with the WUTC on March 28, 2018, in Docket UE-180259. Table B. provides detail on how this IRP addresses each of the rule requirements.

Regulatory implementation of the planning sections of the Clean Energy Transformation Act (CETA) through Docket UE- 190698 specified the development, timing, and required content of an IRP and Clean Energy Action Plan (CEAP). Commission General Order R-601 adopted the amended IRP and CETA compliance rules. PacifiCorp's 2021 IRP was designed to be compliant with the rules in WAC 480-100-600 through WAC 480-100-665.

Wyoming

Wyoming Public Service Commission issued new rules that replaced the previous set of rules on March 21, 2016. Chapter 3, Section 33 outlines the requirements on filing IRPs for any utility serving Wyoming customers. The rule, shown below, went into effect in March 2016.

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 2021 IRP
Idaho		
Case No. PAC-E-19-16, Order No. 34780, p. 13	The Commission expects the Company to actively consider the concerns raised in comments submitted in this case as it plans, and to continue evaluating all resource options and the best interests of customers when developing the 2021 IRP.	PacifiCorp has included a full description of comments received and considered within Volume II, Appendix C (Public Input Process).
Case No. PAC-E-19-16, Order No. 34780, p. 13	The Commission encourages the Company to fully study the costs and benefits of additional transmission resources in its 2021 IRP.	A discussion of the transmission resources studied by the company in the 2021 IRP is included in Volume I, Chapter 4 (Transmission), as well as the chapters addressing resource selection and the Action Plan.
Case No. PAC-E-19-16, Order No. 34780, p. 13	Additionally, the Commission is encouraged by the Company's development of DSM resources and continues to encourage the study, development, and implementation of economical DSM programs.	The implementation of economical DSM programs is described in PacifiCorp's resource selection and action plan chapters (Volume I, Chapters 9 and 10). Studies underlying the DSM resources are posted to the company's IRP website.
Case No. PAC-E-19-16, Order No. 34780, p. 13	The Commission looks forward to observing and working with the Company as it continues to develop time-of-use pricing policies to help shift peak demand in its service territory.	PacifiCorp continues to develop time-of-use pricing and the impact of programs is included in the company's load forecast, included in Volume II, Appendix A (Load Forecast).
Case No. PAC-E-19-16, Order No. 34780, p. 13	Finally, the Commission expects the Company to continue refining and enhancing its forecasting methodologies by analyzing a broad and diverse range of measures to avoid disadvantageous or unfair forecasting treatment of certain resources over others.	PacifiCorp continues to refine and enhance forecasting methodologies as described in Volume II, Appendix A (Load Forecast).
Oregon		
Order No. 20-186, p. 9	Adopt Staffs condition for updated coal analysis (direct PacifiCorp to include in its 2021 IRP development and updated economic study of retirement dates for all the coal units on PacifiCorp's system) on a timeline that informs the 2021 IRP because we view the coal analysis as a fundamental input to the IRP portfolios. Do not require a special coal update prior to the 2021 IRP. We leave this condition flexible, with the direction that PacifiCorp is to include in its 2021 IRP development process an updated analysis identifying the	PacifiCorp held an initial discussion of coal retirement analysis options as part of the December 3, 2020 IRP Public Input meeting. PacifiCorp's modeling system provided multiple retirement options for each relevant coal-fueled generator, modified for the case requirements of each portfolio. Specific retirement dates were optimized as part of the Short-term deterministic analysis. Further discussion of these processes can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach).

Reference	IRP Requirement or Recommendation	How the Guideline is Addressed in the 2021 IRP
	most cost-effective coal retirements individually and in combination.	
Order No. 20-186, p. 10	PacifiCorp is to work with stakeholders on the judgement calls where SCR can be reasonably avoided or not.	PacifiCorp led a discussion on SCRs as part of the December 3, 2020 public input meeting.
Order No. 20-186, p. 10	PacifiCorp is to update its inputs for correct Jim Bridger cost assumptions, as well as update its assumptions to reflect changes to the economy associated with COVID-19.	This input has been corrected and the updated cost assumptions were included in the IRP modeling described in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach). Volume II, Appendix A (Load Forecast) provides additional information on COVID-19's impact on the economy.
Order No. 20-186, p. 10	PacifiCorp is to provide a workshop or update for the Oregon Commission on PacifiCorp's timeline and sequence for incorporating nodal pricing and other MSP issues and EDAM into its IRP process.	PacifiCorp filed the required update with the Oregon Public Utility Commission on December 11, 2020 in Docket No. LC 70.
Order No. 20-186, p. 12-13	We ask PacifiCorp to bring its capacity needs and the economics of its energy position into greater focus through updates and analysis in the RFP docket. We require additional sensitivity analysis and request additional explanation of how PacifiCorp has balanced the near-term cost and optionality benefits of relying on available FOTs against the reliability gains and projected long-term economic benefits of new resource additions.	PacifiCorp provided the sensitivity analyses and requested explanation of how the company has balanced near-term cost and optionality benefits of relying on FOTs against the reliability gains and projected long-term economic benefits of new resource additions as part of the workpapers provided on June 10, 2021 and supplemented on July 25, 2021.
Order No. 20-186, p. 13	Direct PacifiCorp to provide a workshop or presentation on how it calculates the capacity contribution of renewables (including solar and wind co-located with battery storage) for its 2019 and 2021 IRPs.	PacifiCorp provided a workshop on the capacity contribution of renewable resources (including solar and wind co-located with battery storage) as part of the January 2021 IRP Public Input Meeting.
Order No. 20-186, p. 13	Regarding the QF issues, we accept PacifiCorp's commitment to produce a sensitivity or other explanation of the impact of renewing QFs on its load resource balance and direct PacifiCorp to include this in its 2021 IRP.	PacifiCorp has included an explanation of the impact of renewing QFs on its load resource balance as part of Volume I, Chapter 6 (Load and Resource Balance).

Reference	IRP Requirement or Recommendation	How the Guideline is Addressed in the 2021 IRP
Order No. 20-186, p. 14	We adopt Staff's condition with flexibility for PacifiCorp to conduct a workshop anytime in 2020 and for information sharing to occur between parties in a format convenient for participants. (Staff requests PacifiCorp provide a presentation to Staff, Commissioners, and any interested stakeholders who have signed the protective order in this docket regarding the coal mine costs at Jim Bridger and the drivers for the Jim Bridger coal price forecast within 120 days of this docket's acknowledgment order.) During our deliberations we questioned whether this information exchange could occur in an already planned workshop on net power costs. That workshop has since been held, however, and we note that it did not address the specific issue of Jim Bridger fuel price forecasts applicable to the planning timeframe.	PacifiCorp held a workshop to discuss this issue on October 20, 2020.
Order No. 20-186, p.14	We find that PacifiCorp reasonably allowed for additional flexible reserves, given its initial reliability analysis in this IRP, but we also agree with Staff and stakeholders that, for future IRPs, PacifiCorp needs to improve the analytical foundations for incorporating additional reliability resources into the IRP.	PacifiCorp's move to the Plexos modeling system provides a greater analytical foundation for incorporating reliability resources into the IRP. PacifiCorp further discussed compliance with this requirement during the June 25, 2021 and July 30, 2021 public input meetings.
Order No. 20-186, p. 17	We acknowledge Action Item 2a subject to the condition that PacifiCorp files all relevant workpapers for resource acquisition and rate setting in any customer preference RFP with the Oregon Commission in this docket at the time it files a request for waiver or notice of exception under the competitive bidding rules or within 30 days of acquisition of the resource, whichever occurs first.	PacifiCorp acknowledges this requirement.

Reference	IRP Requirement or Recommendation	How the Guideline is Addressed in the 2021 IRP
Order No. 20-186, p. 18	We acknowledge this action item with conditions based on Staff's recommendations. Our conditions on this action item include: Updated load and market forecasts, Off-system sales sensitivities, and customer impacts/ revenue requirement analysis.	PacifiCorp provided materials to Staff and the Independent Evaluator on June 10, 2021, and supplemented information provided on July 25, 2021.
Order No. 18-138, p. 21	Regarding conditions relating to non-wires alternatives, we accept PacifiCorp's offer of a Commission workshop before the 2021 IRP is filed. The workshop should address how PacifiCorp's IRP relates to its long-term transmission plan.	PacifiCorp held a workshop on non-wires alternatives on February 4, 2021.
Order No. 20-186, p. 23	PacifiCorp should work with stakeholders and Staff in the 2021 IRP development process to select two to four bundling strategies in an effort to identify the highest level of cost- effective energy efficiency by state and across the system. The collaborative decision process should consider bundling energy efficiency measures by energy cost, capacity contribution cost and measure type, as well as potentially by other metrics. The company should report on the collaborative process, bundling methods chosen, and any results in a filing before the filing of the 2021 IRP. PacifiCorp may hire a third party to conduct this analysis if needed due to resource constraints, but should coordinate with stakeholders on the scope of the work and timing.	PacifiCorp worked with Staff and stakeholders to select bundling strategies throughout 2020. Energy Efficiency bundles were presented as part of the January 29, 2021 public input meeting.

Reference	IRP Requirement or Recommendation	How the Guideline is Addressed in the 2021 IRP
Order No. 20-186, p. 23	Adopted Staffs conditions, including a modified condition that: PacifiCorp pursue demand response acquisition with a demand response RFP. To the extent practicable, the demand response bids may considered with bids from the all-source RFP. PacifiCorp should work with non-bidding stakeholders from Oregon and other interested states to determine whether PacifiCorp should move forward with cost-effective demand response bids, or with a demand response pilot, or both. PacifiCorp and/or Staff are to provide an update on demand response efforts at a regular public meeting before the 2021 IRP is filed.	PacifiCorp issued a demand response RFP in January 2021 and provided updates as part of the April 23, 2021 public input meeting. PacifiCorp provided an update on demand response efforts on August 16, 2021 and the informational filing was on the consent agenda for the August 24, 2021 regular public meeting.
Order No. 20-186, p. 23	Staff recommends that PacifiCorp conduct a Class 3 DSM workshop. PacifiCorp agreed to provide a stakeholder workshop during 2021 IRP development. We ask that the 2021 IRP summarize the timeframes and participation rates of any existing or planned Class 3 DSM pilots or schedules.	PacifiCorp held Conservation Potential Assessment workshop on August 28, 2020 in compliance with this requirement. A summary of DSM programs and pilots can be found in Volume II, Appendix D (DSM Resources).
Order No. 20-186, p. 24	We acknowledge this action item (6, sale of RECs) and accept PacifiCorp's agreement to add detail to this language in the 2021 IRP to more clearly explain its REC management for states with and without RPS requirements management of RECs.	PacifiCorp has added detail as directed as part of Volume I, Chapter 3 (Planning Environment).
Order No. 20-186, p. 24	Require PacifiCorp include a proposal for the scope of a potential climate adaptation study in its 2021 IRP. This will also allow PacifiCorp to use its next IRP process to solicit stakeholder feedback on the scope of its plan. Additional discussion in the 2021 IRP of adaptation actions already taking place in the course of normal business, such as changes to modeling inputs such as heating and cooling days or water constraints, is encouraged in the meantime.	PacifiCorp has developed a scope for a potential climate adaptation study and the scope is included in Volume I, Chapter 8 (Modeling and Portfolio Evaluation). The company has also prepared a “future climate change” sensitivity that takes into account streamflow, snowpack, rainfall, and changes in heating and cooling degree days. The future climate change scenario is also included in Chapter 8.

Reference	IRP Requirement or Recommendation	How the Guideline is Addressed in the 2021 IRP
Order No. 20-186, p. 25-26	As an IRP housekeeping matter, we seek to reduce the Oregon compliance items that PacifiCorp carries forward in each IRP. We ask PacifiCorp and Staff to review the Oregon compliance list, to determine which items they both agree are no longer relevant or necessary, and to provide an update on the list in the 2021 IRP docket. If certain items are not agreed upon or require our review, we ask Staff to bring those to a public meeting before the 2021 IRP.	PacifiCorp and Commission Staff met during the second quarter of 2021 to discuss opportunities to streamline filing requirements. Following discussions, parties agreed on proposed changes to the reporting process to drive efficiencies, and Staff proposed to recommend the agreed-upon changes for Commission acknowledgement as part of the 2021 IRP Staff Report.
Utah		
Order, Docket No. 19-035-02, p.12	The PTC issue demonstrates the dynamic nature of IRP processes generally, and we find PacifiCorp's treatment of the PTC in the 2019 IRP is consistent with the Guidelines. Because resource approval is a separate process from IRP acknowledgment, though, we fully expect that dockets related to resource approval or a certificate of public convenience and necessity would include adequate evaluation of the PTC extension. We also expect those dockets to give meaningful attention to potential future increases in the Wyoming wind tax.	PacifiCorp acknowledges this requirement.
Order, Docket No. 19-035-02, p.13	Any FERC queue reform will certainly impact some of the issues addressed by the 2019 IRP, but the ongoing nature of that process does not impact whether PacifiCorp substantially complied with the Guidelines in the development of the 2019 IRP. Other dockets, including future integrated resource planning, are appropriate	PacifiCorp acknowledges this requirement and has included a summary of queue reform in Volume I, Chapter 4 (Transmission). PacifiCorp acknowledges that the implications of queue reform will be evaluated in future dockets, including potentially through the Integrated Resource Planning process.

Reference	IRP Requirement or Recommendation	How the Guideline is Addressed in the 2021 IRP
	venues to evaluate the implications of the results of queue reform.	
Order, Docket No. 19-035-02, p.15	Reliability assessments will only become more crucial as PacifiCorp's resource mix changes in the future, and those assessments must become an increasingly core aspect of future IRP processes.	PacifiCorp has included a chapter on reliability and resiliency as part of the 2021 IRP. Additional information can be found in Volume I, Chapter 5 (Reliability and Resiliency).
Order, Docket No. 19-035-02, p.18	We find PacifiCorp has reasonably evaluated DSM in the 2019 IRP considering all appropriate factors necessary to comply with the requirement in Guideline 4.b for a consistent and comparable evaluation of resources, including DSM. In addition, since it appears that many of UCE/SWEEP's concerns stem from the CPA, we find that PacifiCorp has appropriately addressed that issue with a commitment to work with stakeholders to identify potential improvements to the CPA methodology and other modeling changes during the upcoming 2021 IRP process.	PacifiCorp has worked extensively with stakeholders throughout the development of the 2021 IRP. The company held four CPA-specific workshops (January 21, 2020, February 18, 2020, April 16, 2020, and August 28, 2020) and responded to questions/recommendations through the stakeholder feedback form process. Additional information on DSM resources can be found in Volume II, Appendix D (DSM Resources), and information on the recommendations received through the stakeholder feedback process can be found in Volume II, Appendix C (Public Input Process).
Order, Docket No. 19-035-02, p.19-20	We conclude that PacifiCorp's commitment to provide materials three business days in advance of meetings generally satisfies Guideline 3. If a party can demonstrate, in the future, a pattern of unwillingness to provide meeting materials far enough in advance of meetings to allow parties to reasonably prepare, we could consider re-opening the Guidelines to make them more specific.	PacifiCorp acknowledges this ongoing requirement.
Order, Docket No. 19-035-02, p.20-21	We decline to modify the Guidelines at this time to make them more specific in connection with these requests of OCS (requirement of a customer rate impact analysis) and DPU (separate EV forecasts, and trends in the observed forecast overestimation). If a party can demonstrate, in the future, a pattern of unwillingness to provide reasonable responses to information requests, we could consider re-opening the Guidelines to make them more specific.	PacifiCorp acknowledges this requirement.

Reference	IRP Requirement or Recommendation	How the Guideline is Addressed in the 2021 IRP
Order, Docket No. 19-035-02, p. 26	PacifiCorp filed extensive documentation and workpapers with the 2019 IRP. The level of detail is useful and the information provided is well-organized. We commend PacifiCorp for making this information readily available and encourage PacifiCorp to continue to provide such detailed back-up data and workpapers in future IRPs.	PacifiCorp acknowledges this requirement.
Washington		
UE-180259, Order 03 Granting Petition, p.1	A CEIP must be based on an IRP that complies with the new statutory requirements. Specifically, the CEIP must "be informed by the investor-owned utility's clean energy action plan" (CEAP), which is one of the new legislative requirements for electric IRPs. (RCW 19.405.060(1)(b)(i); RCW 19.280.030.)	PacifiCorp acknowledges this requirement and has worked with Commission Staff to ensure that the 2021 IRP is compliant with the new legislative requirements for electric IRPs per RCW 19.405 and RCW 19.280.
UE-180259, Order 03 Granting Petition, p.1	Subsequent electric IRP filings must, therefore, be fully compliant with the new statutory requirements and be filed timely to allow incorporation of the CEAP into the CEIP. (See Chapter 19.405 RCW (Clean Energy Transformation Act (CETA)); RCW 19.280.030; RCW 80.28.405; RCW 19.405.060.)	PacifiCorp's 2021 IRP is compliant with each requirement under CETA as detailed in Table B.5 below.
UE-180259, Order 03 Granting Petition, p.6	Pacific Power & Light Company's next draft IRP must be submitted by January 4, 2021, and its next final IRP must be submitted by April 1, 2021.	In UE-200420, Order 01, the Commission granted PacifiCorp's Petition for Exemption, allowing additional time to complete necessary analysis. PacifiCorp has filed a compliant IRP by September 1, 2021, as directed in Order 01.
UE-200420, Order 02 Requiring Compliance	1(a) Integrate the demand forecasts and resource evaluations into a long-range IRP solution describing the mix of resources that meet current and projected resource needs, abiding by a variety of constraints pursuant to statute and per Commission rule.	PacifiCorp's portfolio modeling process meets this requirement. Inputs are discussed in Volume I, Chapter 6 (Load and Resource Balance) and Chapter 7 (Resource Options). The modeling process and portfolio selection is included in Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection).
UE-200420, Order 02 Requiring Compliance	1(b) Provide a narrative illustrating step-by-step how the social cost of greenhouse gas emissions (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 has included a step-by-step discussion of how SCGHG is applied to the portfolio modeling process as part of Volume I, Chapter 8 (Modeling and Portfolio Evaluation). The summary includes a description of how the SCGHG is included in the model, and which variables are impacted.

Reference	IRP Requirement or Recommendation	How the Guideline is Addressed in the 2021 IRP
UE-200420, Order 02 Requiring Compliance	1(c) 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 resources.	PacifiCorp's 2021 IRP portfolio modeling process included battery and pumped storage as capacity options to integrate renewables. A description of the resources can be found in Volume I, Chapter 7 (Resource Options), and a description of the portfolio selection can be found in Volume I, Chapter 9 (Modeling and Portfolio Selection).
UE-200420, Order 02 Requiring Compliance	1(d) Provide precise analyses and an explanatory narrative describing the alternative lowest reasonable cost and reasonably available portfolio in the absence of CETA. Staff encourages PacifiCorp to exercise its professional judgment regarding many scenario details. However, for additional guidance, PacifiCorp could consider how its peer Washington investor-owned utilities have approached this scenario. For example, Puget Sound Energy's counterfactual scenario has decidedly fewer transmission capacity constraints to serve Washington load since the utility would not need to meet GHG neutral nor 100 percent clean energy targets in 2030 and 2045, respectively. The Commission expects this CETA counterfactual scenario will yield a baseline portfolio that includes the SCGHGs and differs from the CETA-compliant preferred portfolio according to rule.	PacifiCorp's alternative lowest reasonable cost and reasonably available portfolio is described in Volume I, Chapter 8 (Modeling and Portfolio Evaluation). Chapter 8 includes a narrative describing the portfolio, as well as other scenario details.
UE-200420, Order 02 Requiring Compliance	1(e) Include a future climate change scenario as proposed in the company's IRP	A description and narrative of PacifiCorp's future climate change scenario is included in Volume I, Chapter 8 (Modeling and Portfolio Evaluation).
UE-200420, Order 02 Requiring Compliance	1(f) Adjust variables specific to its Washington service territory to develop a more robust maximum customer benefit sensitivity. For example, the Company could consider what level of distributed energy resource penetration within PacifiCorp's Washington service territory would be sufficient to preclude – or at least postpone – high-voltage transmission buildout between Walla Walla and Yakima and/or between Yakima and Southern Oregon. Forgoing constructing such transmission could significantly reduce eminent domain actions that can disproportionately impact vulnerable	A description and narrative of PacifiCorp's maximum customer benefit scenario is included in Volume I, Chapter 8 (Modeling and Portfolio Evaluation).

Reference	IRP Requirement or Recommendation	How the Guideline is Addressed in the 2021 IRP
	populations. This modeling exercise intends to maximize the hypothetical benefit for PacifiCorp’s Washington customers. For the 2021 IRP, this sensitivity’s primary result is additional data and analyses the utility could further refine for its 2022 CEIP and subsequent planning cycles.	
UE-200420, Order 02 Requiring Compliance	1(g) Assess its regional transmission future needs and the extent transfer capability limitations may affect the future siting of resources.	PacifiCorp assesses its regional transmission future needs throughout the IRP process, and additional information on the interaction between transmission availability and future resources can be found in Volume I, Chapter 4 (Transmission), Chapter 8 (Modeling and Portfolio Evaluation), Chapter 9 (Modeling and Portfolio Selection), and Chapter 10 (Action Plan).
UE-200420, Order 02 Requiring Compliance	2(a) [Clean Energy Action Plan (CEAP)] must be at the lowest reasonable cost	PacifiCorp’s CEAP is based on the IRP preferred portfolio, which represents the lowest reasonable cost portfolio that serves customers reliably. A broader discussion of portfolio cost is available in Volume I, Chapter 9 (Modeling and Portfolio Selection).
UE-200420, Order 02 Requiring Compliance	2(b) [CEAP] must identify and be informed by the utility’s ten-year cost effective conservation potential assessment (CPA) as determined in RCW 19.285.040	PacifiCorp’s ten-year CPA provides the inputs to PacifiCorp’s IRP modeling that selects cost effective conservation resources.
UE-200420, Order 02 Requiring Compliance	2(c) [CEAP] must identify how the utility will meet the requirements in WAC 480-100-610(4)(c)	A discussion of CETA’s clean energy transformation standards – including a narrative of how PacifiCorp’s preferred portfolio sets the path to compliance – is part of the “Resource Adequacy” section of Volume II, Appendix O (Washington Clean Energy Action Plan)
UE-200420, Order 02 Requiring Compliance	2(d) [CEAP] must establish a resource adequacy requirement	PacifiCorp sets the resource adequacy requirement through the IRP modeling process, which includes Washington customers. The full-system resource adequacy assessment is included in Volume I, Chapter 6 (Load and Resource Balance), and the planning reserve margin is included for the sake of convenience in the Volume II, Appendix O (Clean Energy Action Plan) as part of the “Resource Adequacy” section.
UE-200420, Order 02 Requiring Compliance	2(e) [CEAP] must identify the potential cost-effective demand response (DR) and load management programs that may be acquired	Volume II, Appendix O (Clean Energy Action Plan) includes a discussion of DR and load management programs as part of the “Resource Adequacy” section.
UE-200420, Order 02 Requiring Compliance	2(f) [CEAP] must identify renewable resources, non-emitting electric generation, and distributed energy resources that may be acquired and evaluate how each identified resource may reasonably be expected to	PacifiCorp discusses these resources at a system level in Volume I, Chapter 9 (Modeling and Portfolio Selection) and Chapter 10 (Action Plan). PacifiCorp also includes a list of the renewable and non-emitting resources in Volume II, Appendix R (Clean Energy Action Plan) within the “Resource Adequacy”

Reference	IRP Requirement or Recommendation	How the Guideline is Addressed in the 2021 IRP
	contribute to meeting the utility's resource adequacy requirement.	section.
UE-200420, Order 02 Requiring Compliance	2(g) [CEAP] must identify any need to develop new, or to expand or upgrade existing, bulk transmission and distribution facilities.	PacifiCorp has fully complied with this requirement. Additional details can be found in Volume I, Chapter 10 (Action Plan) and Volume II, Appendix O (Clean Energy Action Plan).
UE-200420, Order 02 Requiring Compliance	2(h) [CEAP] must identify the nature and possible extent to which the utility may need to rely on an alternative compliance option identified under RCW 19.405.040(1)(b), if appropriate; and	PacifiCorp's preferred portfolio – included in Volume I, Chapter 9 (Modeling and Portfolio Selection) – meets the requirements under CETA's clean energy standards. A high-level discussion of compliance risk is also included in Volume II, Appendix O (Clean Energy Action Plan).
UE-200420, Order 02 Requiring Compliance	2(i) [CEAP] must incorporate the social cost of greenhouse gas emissions as a cost adder as specified in RCW 19.280.030(3).	PacifiCorp included social cost of greenhouse gas as a cost adder throughout the modeling process – including in portfolios that were considered to ultimately inform Volume II, Appendix O (Clean Energy Action Plan). Additional discussion of how the social cost of greenhouse gas emissions was incorporated into the modeling can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation).
UE-200420, Order 02 Requiring Compliance	3(a) Identify an appropriate resource adequacy requirement and complete the assessment, as required by WAC 480-100-620(8)	PacifiCorp's assessment and determination of resource adequacy metrics is included in Volume I, Chapter 6 (Load and Resource Balance) and Chapter 8 (Modeling and Portfolio Evaluation). A discussion of regional resource adequacy is included in Volume I, Chapter 5 (Reliability and Resiliency).
UE-200420, Order 02 Requiring Compliance	3(b) 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: 1)cost assumptions; 2)production estimates; 3)peak capacity contribution estimates and annual capacity factor estimates	PacifiCorp will include these assumptions as part of the data disk process.
UE-200420, Order 02 Requiring Compliance	3(c) develop a detailed narrative describing the logic used in the Plexos LTCE and medium-term model that determine whether low-cost energy efficiency or demand response are developed or dispatched.	The logic underlying the Plexos LTCE will be included in Volume I, Chapter 8 (Modeling and Portfolio Evaluation).

Reference	IRP Requirement or Recommendation	How the Guideline is Addressed in the 2021 IRP
UE-200420, Order 02 Requiring Compliance	3(d) 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.	A discussion of PacifiCorp's portfolio selection parameters is included in Volume I, Chapter 9 (Modeling and Portfolio Selection) as well as in Volume I, Chapter 10 (Action Plan).
UE-200420, Order 02 Requiring Compliance	4(a) Augment its load forecasting chapter and supporting appendices with significantly more details. Staff expect to see the data inputs used in the calculation and estimated regression results in native file format	PacifiCorp will provide the data inputs and estimated regression results along with the IRP data disks sent shortly after filing. Volume II, Appendix A (Load Forecast) has been updated where possible.
UE-200420, Order 02 Requiring Compliance	4(b) Address WAC 480-100-620(2), including more information and discussion regarding treatment of: 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; and 3) electrification adjustments made to the load forecast.	PacifiCorp included narrative to discuss the climate change scenario, electrification adjustments, and assumptions in low and high load growth models within Volume II, Appendix A (Load Forecast). The climate change load forecast is further discussed in Volume I, Chapter 5 (Reliability and Resiliency) and Chapter 8 (Modeling and Portfolio Evaluation).
UE-200420, Order 02 Requiring Compliance	5(a) file the conservation potential assessment (CPA) as an appendix or attachment to the final IRP and specifically provide the: 1) CPA model and underlying data; 2) DR potential model and underlying data	PacifiCorp has included the CPA as part of the IRP filing. Underlying data will be provided as part of the data disk process.
UE-200420, Order 02 Requiring Compliance	5(b) identify the DSM grid benefits, explaining benefits: 1) Endogenous within LTCE portfolio optimization 2) Separately determined during the CPA process	Grid benefits endogenously determined within the long-term capacity expansion portfolio optimization process are discussed in Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection).
UE-200420, Order 02 Requiring Compliance	5(c) Describe how the Plexos LTCE model harmonizes differences in technical achievable potential when the optimization process applies different load growth forecasts.	The description of the Plexos long-term capacity expansion process and the selection of DSM is included in Volume I, Chapter 8 (Modeling and Portfolio Evaluation).

Reference	IRP Requirement or Recommendation	How the Guideline is Addressed in the 2021 IRP
UE-200420, Order 02 Requiring Compliance	6(a) demonstrate consideration of a wider incorporation of non-energy impacts (NEIs) in addition to NEI applications during CPA development.	A narrative consideration of NEIs is discussed in Volume II, Appendix O (Clean Energy Action Plan). NEIs by energy efficiency measure included in the CPA are found in Appendix G of the 2021 CPA. A review of NEIs for demand response is found Appendix J of the 2021 CPA PacifiCorp IRP team applied NEI proxy in the 2021 IRP. Proxy will be the EPA EE NEI value for public health benefits, •Applied to WA EE resources in Social Cost of Carbon cases. •Value is 2.8 c/kWh in 2017$ (Table ES-1, high value of Pacific NW for Uniform EE). It will be grossed up to 2020 dollars to be consistent with the rest of the IRP model assumptions. •Link to study: https://www.epa.gov/statelocalenergy/public-health-benefits-kwh-energy-efficiency-and-renewable-energy-united-states
UE-200420, Order 02 Requiring Compliance	6(b) Attribute NEIs considered, indicating whether nonenergy costs and benefits accrue to the utility, customers, participants, vulnerable populations, highly-impacted communities, or the general public.	Accrual of NEIs is discussed in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach).
UE-200420, Order 02 Requiring Compliance	6(c) Specifically address vulnerable populations and quantify disparate impacts existing within PacifiCorp's Washington service territory in its current-state assessment of economic, health, and environmental impacts.	A preliminary list identifying vulnerable populations and a quantification of disparate impacts within PacifiCorp's Washington service area is discussed in Volume II, Appendix O (Clean Energy Action Plan).
UE-200420, Order 02 Requiring Compliance	7(a) summarize public comments received during the 2021 IRP development rather than providing a download of stakeholder feedback forms received to date.	A summary of public comments and PacifiCorp responses – including whether/how the feedback was incorporated into the 2021 IRP – is included in Volume II, Appendix C (Public Input Process).
UE-200420, Order 02 Requiring Compliance	7(b) Summarize utility's corresponding responses to public comments; and	A summary of public comments and PacifiCorp responses – including whether/how the feedback was incorporated into the 2021 IRP – is included in Volume II, Appendix C (Public Input Process).
UE-200420, Order 02 Requiring Compliance	7(c) Summarize whether and how final plan addresses and incorporates comments received.	A summary of public comments and PacifiCorp responses – including whether/how the feedback was incorporated into the 2021 IRP – is included in Volume II, Appendix C (Public Input Process).

Reference	IRP Requirement or Recommendation	How the Guideline is Addressed in the 2021 IRP
UE-200420, Order 02 Requiring Compliance	8(a) provide all data input files to the Commission in native format with appropriate context as appendices or attachments to the final filing or via accompanying data disks. Data made available in this accessible manner will facilitate understanding of why PacifiCorp took the actions it did and assist in the independent review of such actions	PacifiCorp will provide all data input files as part of the data disk process in the week(s) following the filing of the IRP on September 1, 2021.
UE-200420, Order 02 Requiring Compliance	8(b) include complete data sets informing the Company's preferred portfolio. Supporting data and workpapers should allow a 2019-to-2021 comparison of resource need	PacifiCorp will provide all data input files as part of the data disk process in the week(s) following the filing of the IRP on September 1, 2021.
UE-200420, Order 02 Requiring Compliance	8(c) Ensure supporting data is easily accessible to interested parties by including contextual aids with the given information. At minimum, the company should organize its final IRP deliverable by including a master table of contents, readme files, and categorically grouping related data.	PacifiCorp will provide all data input files as part of the data disk process in the week(s) following the filing of the IRP on September 1, 2021.
Wyoming		
Order, Docket No. 9000-144-XI-19 (Record No. 15280)	Include a Reference Case based on the 2017 IRP Updated Preferred Portfolio, incorporating updated assumptions, such as load and market prices and any known changes to system resources and using environmental investments or costs only required by current law. For example, the reference case will not include an estimate or assumed price or cost for carbon emissions absent an existing legal requirement	PacifiCorp has complied with this requirement. Additional information on the specified reference case can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach).
Order, Docket No. 9000-144-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 Approach) and Chapter 9 (Modeling and Portfolio Selection).
Order, Docket No. 9000-144-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 Approach) and Chapter 9 (Modeling and Portfolio Selection Results).
Order, Docket No. 9000-144-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 – 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.

Reference	IRP Requirement or Recommendation	How the Guideline is Addressed in the 2021 IRP
Order, Docket No. 9000-144-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. 9000-144-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 Approach) and Chapter 9 (Modeling and Portfolio Selection) provide additional detail.
Order, Docket No. 9000-144-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. 9000-144-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 2021 IRP. Advanced nuclear and natural gas resources have both been included in the supply-side table and analyzed in the 2021 IRP.
Order, Docket No. 9000-144-XI-19 (Record No. 15280)	Include a narrative discussing impacts and regulatory framework for renewable generation in the Planning Environment discussion (chapter 3).	PacifiCorp has added this narrative analysis to the Planning Environment discussion in Volume I, Chapter 3 (Planning Environment).
Order, Docket No. 9000-144-XI-19 (Record No. 15280)	Include an acknowledgement that each of these requirements are addressed in the 2021 IRP to ensure compliance.	PacifiCorp acknowledges these requirements and has addressed each within the 2021 IRP.

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

No.	Requirement	How the Guideline is Addressed in the 2021 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 Approach) 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 Approach), 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 Approach) as well as Volume II, Appendix D (Demand-Side Management Resources).
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 6.88 percent to discount all cost streams.

No.	Requirement	How the Guideline is Addressed in the 2021 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 with the exception of 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 Approach) 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 Approach), 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 (2021-2040) 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 Approach) 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 Approach) 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 (The 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 2021 IRP, and summarizes public input received throughout the 2021 IRP cycle. PacifiCorp also made use of a Stakeholder Feedback Form for stakeholders to provide comments and offer suggestions. Stakeholder Feedback Forms along with the public-input meeting presentations are available on PacifiCorp's webpage at: www.pacificorp.com/energy/integrated-resource-plan.html
2.b	While confidential information must be protected, the utility should make public, in its plan, any non-confidential information that is relevant to its resource evaluation and action plan. Confidential information may be protected through use of a protective order, through aggregation or shielding of data, or through any other mechanism approved by the Oregon PUC.	2021 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 2021 IRP. The materials shared with stakeholders at these meetings, outlined in Volume II, Appendix C (Public Input Process), is consistent with materials presented in Volumes I and II of the 2021 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 2021 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 2021 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 2021 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 Approach), and Volume II, Appendix A (Load Forecast Detail) for load forecast information.

No.	Requirement	How the Guideline is Addressed in the 2021 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 Approach).
4.d	For gas utilities only.	Not applicable.
4.e	Identification and estimated costs of all supply-side and demand side resource options, taking into account 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 Approach).
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 Approach) describes the key assumptions and alternative scenarios used in this IRP. Volume II, Appendix I (Capacity Expansion Detail) includes summaries of assumptions used for each case definition analyzed in the 2021 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 Approach) 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) presents the stochastic portfolio modeling results, 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 2021 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 2019 IRP action plan.

No.	Requirement	How the Guideline is Addressed in the 2021 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.
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 8 (Modeling and Portfolio Selection Results), the targeted amounts in Volume I, Chapter 9 (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 (Class 1 DSM) on a consistent basis with other resources.

Guideline 8: Environmental Costs		
No.	**Requirement**	**How the Guideline is Addressed in the 2021 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 Approach). In the 2021 IRP, PacifiCorp modeled a price on CO2 starting in 2021 within the Social Cost of Greenhouse Gas price-policy scenarios.
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 Approach) 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.

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 Approach) 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).

No.	Requirement	How the Guideline is Addressed in the 2021 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 2021 IRP conforms to the multi-state planning approach as stated in Volume I, Chapter 2 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 Guidehouse 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 2021 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 2019 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.	See 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.	See 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.	See 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 2021 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 2021 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 Process). 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 Approach) for a description of the methodology employed, including how CO2 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 PacifiCorp's capacity expansion optimization model. 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 2021 IRP preferred portfolio and December 2020 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 2021 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, in order 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 Approach) 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 October 18, 2019, and filed this IRP on September 1, 2021, meeting the requirement. PacifiCorp requested and was granted an extension of time to file the 2019 IRP in Docket No. 21-035-09.
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 Details).
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 Details). 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	Volume II, Appendix A (Load Forecast Details) documents how demographic and price factors are used in PacifiCorp's load forecasting methodology.

	loads.	

No.	Requirement	How the Guideline is Addressed in the 2021 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 System Optimizer model and Planning and Risk production cost model using both supply side and demand side alternatives. See explanation in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach) 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 (Class 1) DSM (dispatchable/schedulable load control) and Energy Efficiency (Class 2) DSM 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. Volume I, Chapters 7 (Resource Options) and 8 (Modeling and Portfolio Evaluation Approach) 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 (2021-2040).
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 9.1 identifies actions anticipated in the next two-to-four years.

No.	Requirement	How the Guideline is Addressed in the 2021 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: ● Top performing portfolios were evaluated using a range of CO2 price-policy scenarios. ● A discussion of environmental policy status and impacts on utility resource planning is provided in Volume I, Chapter 3 (The 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). ● 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 2021 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 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, 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.	PacifiCorp incorporated environmental externality costs for CO2 and costs for complying with current and proposed U.S. EPA regulatory requirements. For CO2 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 Approach).
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 (The 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 2019 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 2019 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 2019 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 2019 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 2021 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.

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 2021 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.
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 2021 (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 are impractical.
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, and High/no customer preference. Other load variants will be considered on the basis of stakeholder feedback and model outcomes. A discussion of load forecasts will be included in a Load and Resource Balance chapter.
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 Details). 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 2021 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 Evaluation Approach), 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 Guidehouse 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 Approach).
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 Approach). 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.

No.	Requirement	How the Guideline is Addressed in the 2021 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 Approach) 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.
WAC 480-100-620(5)	Plan assesses nonconventional generating, integration, and ancillary service technologies.	Compressed air storage and modular 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), and
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 2021 IRP
	transfer capability limitations may affect the future siting of resources.	transmission rights and endogenous transmission upgrade options. These factors will be discussed in the Resource Options, and Modeling and Portfolio Evaluation chapter of the IRP.
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 Approach) 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 Approach).
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 five core SC-GHG cases, each to be evaluated under a range of price-policy conditions and which will compete with other cases for CETA compliance and preferred portfolio selection. The cases evaluated are described in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach).
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. A summary of benefits accruing is included as part of Volume II, Appendix O (Washington Clean Energy Action Plan).
WAC 480-100-620(7)	- resource preference public policies adopted by WA State or the federal government.	The preferred portfolio selected in the 2021 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 Approach).
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.

No.	Requirement	How the Guideline is Addressed in the 2021 IRP
WAC 480-100-620(8)	Plan assesses and determines resource adequacy metrics.	For the 2021 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 Approach).
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 described in Volume I, Chapter 6 (Load and Resource Balance), Chapter 8 (Modeling and Portfolio Evaluation Approach), and Chapter 9 (Modeling and Portfolio Selection Results). Additional information on the Washington-specific portfolio view is available in Volume II, Appendix O (Washington Clean Energy Action Plan).
WAC 480-100-620(9)	Plan reflects the cumulative impact analysis conducted under RCW 19.405.140, and includes an assessment of:	PacifiCorp has incorporated information from the Cumulative Impact Analysis, the Washington Tracking Network, and the US Census. Information derived from the Cumulative Impact Analysis is included in Volume II, Appendix O (Washington Clean Energy Action Plan).
WAC 480-100-620(9)	- energy and nonenergy benefits;	PacifiCorp analyzes energy benefits within selection of the preferred portfolio. Non-energy benefits are included with DSM measures, and additional nonenergy benefits are qualitatively discussed within Volume II, Appendix O (Washington Clean Energy Action Plan).
WAC 480-100-620(9)	- reduction of burdens to vulnerable populations and highly impacted communities;	A preliminary identification of burdens to vulnerable populations and highly-impacted communities has been made through data publicly available through the Cumulative Impacts Analysis, Washington Tracking Network, and the US Census, and included in Volume II, Appendix O (Washington Clean Energy Action Plan). PacifiCorp will continue to refine this data in consultations with the public and advisory groups moving forward.
WAC 480-100-620(9)	- long-term and short-term public health and environmental benefits, costs, and	A preliminary identification of burdens to vulnerable populations and highly-impacted communities has been made through data publicly available through the Cumulative Impacts Analysis, Washington Tracking Network, and the US Census, and included in Volume II, Appendix O (Washington Clean Energy Action Plan). PacifiCorp will continue to refine this data in consultations with the public and advisory groups moving forward.

No.	Requirement	How the Guideline is Addressed in the 2021 IRP
WAC 480-100-620(9)	- long-term and short-term public health and environmental risks; and	A preliminary identification of burdens to vulnerable populations and highly impacted communities has been made through data publicly available through the Cumulative Impacts Analysis, Washington Tracking Network, and the US Census, and included in Volume II, Appendix O (Washington Clean Energy Action Plan). PacifiCorp will continue to refine this data in consultations with the public and advisory groups moving forward.
WAC 480-100-620(9)	- energy security and risk.	PacifiCorp addresses energy security and risk throughout the IRP, and specifically addresses this in Volume I, Chapter 5 (Reliability and Resiliency) and Chapter 9 (Modeling and Portfolio Selection Results).
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 Approach).
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 Approach).
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 Approach).
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 Approach).
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 2021 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:	
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 Approach) and Chapter 9 (Modeling and Portfolio Selection Results).
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 2021 IRP timeline, but generally may be addressed as part of Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection).
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 2021 IRP timeline, but the pathway to 2045 is generally addressed as part of Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach) and Chapter 9 (Modeling and Portfolio Selection).
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 Approach).
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, 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 Approach).
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 Approach).
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 2021 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;	This is discussed as part of Volume II, Appendix O (Washington Clean Energy Action Plan).
WAC 480-100-620(11)(g)	- long-term and short-term public health and environmental benefits; reduction of costs and risks; and	This is discussed as part of Volume II, Appendix O (Washington Clean Energy Action Plan).
WAC 480-100-620(11)(g)	- energy security and resiliency.	This is discussed as part of Volume I, Chapter 5 (Reliability and Resiliency), Chapter 6 (Load and Resource Balance), and Chapter 9 (Modeling and Portfolio Evaluation Results).
WAC 480-100-620(11)(h)	Preferred portfolio: assesses the environmental health impacts to highly impacted communities,	This is discussed as part of Volume II, Appendix O (Washington Clean Energy Action Plan).
WAC 480-100-620(11)(i)	- analyzes and considers combinations of DER costs, benefits, and operational characteristics (incl. ancillary services) to meet system needs,	Detail is included in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach).
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 Approach).
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:	
WAC 480-100-620(12)(b)	- identify and be informed by utility's ten-year CPA per RCW 19.285.040(1);	The Washington Clean Energy Action Plan is informed by the 10-year CPA, which can be found on PacifiCorp's website.
WAC 480-100-620(12)(c)	- demonstrate that all customers are benefiting from the transition to clean energy;	This requirement is included in Volume II, Appendix O (Washington Clean Energy Action Plan), which discusses vulnerable populations and highly-impacted communities and a discussion of benefits from the preferred portfolio.
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). A summary of DR and load management programs in Washington are included in Volume II, Appendix O (Washington Clean Energy Action Plan).
WAC 480-100-620(12)(f)	- identify renewable resources, nonemitting 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 Approach), and Chapter 9 (Modeling and Portfolio Selection) provide additional detail.

No.	Requirement	How the Guideline is Addressed in the 2021 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 action plan (Volume I, Chapter 10).
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.	This requirement is addressed in Volume II, Appendix O (Washington Clean Energy Action Plan).
WAC 480-100-620(12)(i)	Plan (both IRP and CEAP) considers cost of greenhouse gas emissions as a **cost adder** equal to the cost per metric ton of carbon dioxide emissions, using the two and one-half percent discount rate, listed in Table 2, Technical Support Document: Technical update of the social cost of carbon (SCC) for regulatory impact analysis under Executive Order 12866, published by the interagency working group on social cost of greenhouse gases of the United States government, August 2016, as adjusted by the Commission to reflect the effect of inflation.	This requirement will be included in Appendix R - Clean Energy Action Plan, within the "Resource Adequacy" section. For the IRP, this requirement will be included as part of the "Modeling and Portfolio Evaluation Approach" section.
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):	
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 Approach) 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 Approach) 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 Approach) 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 Approach) 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 Approach) and Chapter 9 (Modeling and Portfolio Selection).

No.	Requirement	How the Guideline is Addressed in the 2021 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).	PacifiCorp provides a preliminary determination of accrual of energy and non-energy benefits within Volume II, Appendix O (Washington Clean Energy Action Plan).

No.	Requirement	How the Guideline is Addressed in the 2021 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:	
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 Approach) 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 Approach) 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 Approach) 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 Approach) 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 Approach) 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 Approach).
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 Guideline

No.	Requirement	How the Guideline is Addressed in the 2021 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 Approach) 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 Approach).
I	Demand-side management and conservation options;	See Volume I, Chapter 7 (Resource Options) 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.

Stakeholders have been involved in the development of the 2021 IRP from the beginning. The public-input meetings held beginning in January 2020 were the cornerstone of the direct public- input process, and there have been a total of 18 public-input meetings held as part of the 2021 IRP development cycle. Due to restrictions and concerns surroundings 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 July 2020. 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 2021 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

- Alliance of Western Energy Consumers
- Applied Energy Group
- Avangrid
- Black & Veatch
- Breathe Utah
- Burns & McDonnell Engineering Company
- Cascade Natural Gas
- City of Kemmerer Wyoming
- Clarke Investments, LLC
- Enel Green Power
- Energy Trust of Oregon
- First Solar
- Gardner Energy
- Glenrock Energy
- Heal Utah
- Holladay United Church of Christ
- Idaho Conservation League
- Idaho Power Company
- Idaho Public Utility Commission Staff
- Individual Customers
- Intermountain Wind
- Lincoln County Commission
- Magnum Development
- National Grid Ventures
- Natural Resources Defense Council
- Navigant Consulting, Inc.
- Northwest Pipeline GP
- Oregon Department of Energy
- Oregon Department of Justice
- Oregon Public Utility Commission Staff
- Portland General Electric
- Power Quip
- Renewable Northwest
- Sierra Club
- Utah Clean Energy
- Utah Division of Public Utilities
- Utah Office of Consumer Services
- Utah Office of Energy Development
- Washington Office of Attorney General, Public Counsel Unit
- Western Resource Advocates

- Westmoreland
- Wyoming Coalition of Local Governments & Lincoln County
- Wyoming Department of Workforce Services
- Wyoming House District 18
- Wyoming Infrastructure Authority
- Wyoming Liberty Group
- Wyoming Office Of Consumer Advocate

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.

Public-Input Meetings

As mentioned above, PacifiCorp has hosted 10 public-input meetings, as well as six state meetings during the public-input process, with two additional public-input meeting scheduled for early 2021. During the 2021 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:

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

General Meetings

January 21, 2020 – Conservation Potential Assessment (CPA) Technical Workshop 1 (Conference Call)

- Conservation Potential Assessment Overview
- Key Changes and Updates for the 2021 CPA
- Market Characterization and Baseline Development
- Measure Characterization and Potential Estimation
- 2021 CPA Work Plan

February 18, 2020 – CPA Technical Workshop 2 (Conference Call)

- Energy Efficiency
- Measure List Changes
- Demand Response
- Resource Options and Examples

April 16, 2020 – CPA Technical Workshop 3 (Conference Call)

- CPA Schedule and Milestones
- Stakeholder Feedback
- Recap of Key Discussion Topics From Prior Workshops
- Drivers of difference in Forecasted Potential by State

June 18-19, 2020 – General Public Meeting (Conference Call)

Day One

- Stakeholder Feedback Form Update
- CPA Update
- Optimization Modeling and Modeling Update
- Modeling Energy

Storage Day Two

- 2019 IRP Highlights/ 2021 IRP Topics and Timeline
- Request for Proposal (RFP) Update
- Transmission Overview and Update

July 30-31, 2020 – General Public Meeting (Conference Call)

Day One

- Load Forecast Update
- Distribution System Planning
- Supply-side Resource Study Efforts
- Endogenous Retirement

Discussion Day Two

- Environmental Policy
- Renewable Portfolio Standards
- DMS Bundling Portfolio Methodology
- Private Generation Study
- Stakeholder Feedback Form Recap

August 28, 2020 – CPA Technical Workshop 4 (Conference Call)

- 2021 CPA Process Review
- Energy Efficiency Potential Draft Results
- Demand Response Potential Draft Results

September 17, 2020 – General Public Meeting (Conference Call)

- Supply-side Resources
- Portfolio Development Discussion
- State Policy Update
- Conservation Potential Assessment Update
- Stakeholder Feedback Form Recap

October 22, 2020 – General Public Meeting (Conference Call)

- Supply-Side Resource Table Results
- Conservation Potential Assessment Final Results
- Energy Efficiency Bundling Methodology

- Market Reliance Assessment
- PLEXOS Benchmark Update
- Environmental Policy: Regional Haze Update
- Stakeholder Feedback Form Recap

November 16, 2020 – General Public Meeting (Conference Call)
- PLEXOS Benchmark Update
- Modeling Assumptions Update
- All Source Request for Proposals Update
- Stakeholder Feedback Form Recap

December 3, 2020 – General Public Meeting (Conference Call Only)
- Portfolio Development
- Carbon Capture Supply-Side Resource Table
- Price Curve and Customer Preference Update
- Transmission Modeling Assumptions
- Stakeholder Feedback Form Recap

January 29, 2021 – General Public Meeting (Conference Call and Teams Meeting)
- Energy Efficiency Bundling Methodology
- Multi-State Process and Extended Day-Ahead Market Update
- Stakeholder Feedback Form Recap

February 10, 2021 – General Public Meeting (Conference Call and Teams Meeting)
- Discussion of current IRP status
- Stakeholder Feedback Form Recap

April 22-23, 2021 – General Public Meeting (Conference Call and Teams Meeting)
- Update on IRP filing extension regulatory process
- Discussion of RFP status
- Stakeholder Feedback Form Recap

June 25, 2021 – General Public Meeting (Conference Call and Teams Meeting)
- Discussion of portfolios due to incorporation of AS RFP final short list results, discussion of cost and risk portfolio analysis; opportunity for stakeholder feedback.

July 30, 2021 – General Public Meeting (Conference Call and Teams Meeting)
- Discuss selection of portfolio optimization and portfolio modeling progress, update on state energy policy; opportunity for stakeholder feedback.

August 6, 2021 – General Public Meeting (Conference Call and Teams Meeting)

- Discussion of portfolio modeling – including sensitivities and scenario runs.

August 27, 2021 – General Public Meeting (Conference Call and Teams Meeting)

- Review portfolio modeling, portfolio development process, and preferred portfolio.

State-Specific Input Meetings

July 22, 2020 – Utah State Stakeholder Meeting
July 22, 2020 – Washington State Stakeholder Meeting
July 23, 2020 – Wyoming State Stakeholder Meeting
July 24, 2020 – Oregon State Stakeholder Meeting

Stakeholder Comments

For the 2021 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 August 31, 2021, PacifiCorp has received 91 Stakeholder Feedback Forms with over 480 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 2021 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:

- Able Grid Energy Solutions
- City of Kemmerer, Wyoming
- Cadmus Group
- Idaho Conservation League
- Idaho Public Utility Commission Staff
- Individual Stakeholders
- Interwest Energy Alliance
- Northwest Energy Coalition
- Oregon Citizens' Utility Board
- Oregon Public Utility Commission Staff
- Powder River Basin Resource Council
- Renewable Northwest
- Sierra Club
- Southwest Energy Efficiency Project

- Utah Clean Energy
- Utah Valley Earth Forum
- Washington Utilities and Transportation Commission Staff
- Western Resource Advocates
- Wyoming Industrial Energy Consumers
- Wyoming Office of Consumer Advocate

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

Carbon Price

Sierra Club requested additional information on carbon pricing (which PacifiCorp subsequently presented as part of the November 16, 2020 IRP public-input meeting) and a scenario where carbon pricing would be applied in only some of the company's jurisdictions. PacifiCorp included carbon price sensitivities, but the price was applied across all jurisdictions.[1]

Coal Analysis

Washington Utilities and Transportation Commission Staff asked for more information about the cost and physical supply risk of coal fuel to the Colstrip plant. PacifiCorp responded that the IRP modeling considers fuel price in dispatch decisions, and while fuel-supply risk is not explicitly modeled in the IRP, the modeling does consider operational characteristic for heat rates, minimum-up and maximum-down times, ramp rates, and minimum capacity for dispatch decisions.[2]

Washington Utilities and Transportation Commission staff asked about supply-risk of fuel and potential market alternatives to the continued operation of the Jim Bridger mine. PacifiCorp responded that IRP modeling considers fuel price in dispatch decisions, and the dispatch cost of a facility is compared to the sales market price to determine whether the operation or sale is economic and providing a net benefit to customers.[3]

The City of Kemmerer asked that PacifiCorp include carbon capture and coal gasification technology be included in the 2021 IRP. PacifiCorp has included consideration in the 2021 IRP, and discussed these technologies specifically in the September 17, 2020 public input meeting.[4]

Washington Utilities and Transportation Commission Staff requested an economic analysis of closing/divesting Colstrip units 3 and 4 earlier than 2025. PacifiCorp and staff agreed to a "bookend" approach by developing cases that would close/divest Colstrip as early as the end of 2022 and as late as 2027.[5]

Sierra Club requested additional information on the cost assumptions for major coal unit overhauls, whether those overhauls include pollution control technology, coal operating limits, and operating

[1] Feedback Form 052; October 19, 2020
[2] Feedback Form 013; June 26, 2020
[3] Feedback Form 013; June 26, 2020
[4] Feedback Form 025; August 28, 2020
[5] Feedback Form 069; December 11, 2020

variant assumptions. PacifiCorp provided the requested detail in the feedback form response.[6] Sierra Club asked a follow up requesting more information on the definitions of operating limits, which PacifiCorp provided.[7] Sierra Club further requested information on pricing tiers and how fuel considerations were modeled within Plexos.[8]

Catriona Buhayar expressed concern regarding ongoing investment into coal power plants over the next ten years rather than focusing on retirement and investment in renewables. PacifiCorp responded that all options were being considered and the supply-side table provides additional information regarding potential resources for future investment.[9]

Wyoming Public Service Commission Staff requested additional information regarding what would be considered in the coal-fueled resource decommissioning studies and reassignment filings and the extent to which those inputs would be included in the 2021 IRP. PacifiCorp provided the requested detail as part of the feedback form response.[10]

Conservation Potential Assessment (CPA)/Energy Efficiency/Demand Response

Utah Valley Earth Forum requested that the company provide more attention for renewable-fuel power generation or for conventional cogeneration for the purposes of improving grid efficiency and resilience.[11]

Utah Valley Earth Forum provided a list of potential additions to the 20221 Residential Measure list. PacifiCorp provided explanations of which were currently included, and which could be considered in the 2021 CPA.

Southwest Energy Efficiency Project and Utah Clean Energy jointly made multiple recommendations as part of the CPA process:

- The CPA should look at the potential for demand response to expand potential beyond capacity and consider how it could offer services such as frequency regulation and contingency reserves. PacifiCorp addressed this recommendation at the February 18, 2020 IRP Public-Input meeting and noted that in the 2019 IRP, there was a credit applied for operating reserves for DR, which also tried to capture grid services benefits through "ancillary services."

- The CPA should assess the potential for DR to shift load on a daily basis to help integrate renewables. PacifiCorp responded that it was open to exploring ways of adapting modeling tools to provide this functionality but noted that DR was not as controllable as battery storage.

- The 2021 CPA should not assign the full cost of DR enabling technologies to the

[6] Feedback Form 071; December 18, 2020
[7] Feedback Form 078; April 13, 2021
[8] Feedback Form 085; August 3, 2021
[9] Feedback Form 072; January 19, 2021
[10] Feedback Form 076; February 10, 2021

levelized cost of DR. PacifiCorp committed to revisiting the costs for all measures and will consider cost assumption recommendations through the CPA stakeholder engagement process.

- The CPA should consider the impacts of interactive effects between energy efficiency and DR in all states, including those that use the Utility Cost Test. PacifiCorp noted that in the 2019 CPA, the company discounted participant costs in California, Oregon, Washington, and Wyoming to account for DR and energy efficiency interactions. For the 2021 CPA, the company committed to investigating the treatment of cost proxies in all states.

- Additional information should be provided regarding the methodology to treat interactive effects between DR and pricing and rates measures (as pricing and rates potential is not included in the IRP modeling process). PacifiCorp responded that DR is included in the IRP model, and pricing and rates programs are accounted for in the IRP load forecast.

- The CPA should include a low, medium, and high case for Technically Achievable Potential. PacifiCorp responded that it would consider this request as the 2021 CPA progress progressed.

- Request for transparency regarding assumptions for Market Adoption Rates and any corrections. PacifiCorp committed to providing stakeholders an opportunity to review measure adoption rates during the CPA development process and any “outside” the model changes that could affect the technical potential.

- Requested analysis for measure-level levelized cost and supply assumptions from 2019, 2017, and 2015 CPAs with historical measure-level cost and program achievements in each jurisdiction. PacifiCorp committed to conducting a subset of that analysis as part of the 2021 CPA.

Utah Clean Energy sought additional information regarding how “emerging” CPA and DSM measures were treated compared to standard DSM measures. PacifiCorp noted that there is no inherent difference (save for potentially a faster ramp rate), but that the company would work with Utah Clean Energy and Southwest Energy Efficiency Project to explore the possibility of modeling declining cost within the 2021 IRP for emerging technologies.

Utah Clean Energy provided recommendations on which measures should be considered “emerging.” PacifiCorp considered this feedback and ultimately removed the “emerging” distinction from a number of measures.

Utah Clean Energy requested additional information regarding technical achievable potential, data underlying light-emitting diode market adoption, and other conservation potential assumptions. PacifiCorp responded to all questions and provided data as requested.[12]

The Oregon Citizen’s Utility Board made a number of recommendations regarding low-income assistance, moving the Oregon Irrigation Load Control beyond a pilot program, and pricing and

[12] Feedback Form 036; September 18, 2020

rates recommendations. PacifiCorp noted that it was extending the Oregon program and appreciated the suggestion for low-income assistance. PacifiCorp referred pricing recommendations to the (then) ongoing general rate case.

Staff of the Washington Utilities and Transportation Commission provided recommendations that would increase the accessibility of reviewing CPA measures, including a “crosswalk” that would allow comparison of approaches, measures grouped by program option, ability to save spreadsheets locally, and expanded abbreviations. PacifiCorp removed password protection on the online copies of the workbooks so that they could be saved, provided an “introduction” spreadsheet within each list that defines terms, and provided an explanation of how a “crosswalk” could be derived from materials on the PacifiCorp website.

Staff of the Oregon Public Utility Commission requested additional information regarding whether the costs for a residential smart thermostat have been updated with advanced metering infrastructure deployment complete. PacifiCorp responded that projects that were reliant on advanced metering infrastructure were only analyzed after the advanced metering infrastructure was assumed to be deployed. Additional information is included in the 2019 CPA.[13][14][15] Staff further recommended that the company follow the California Public Utilities Commission’s methodology for program incentives and recommended participant cost values. PacifiCorp incorporated all recommendations.[16]

Southwest Energy Efficiency Project and Utah Clean Energy also provided feedback on the Conservation Potential Assessment workplan process in general, including providing all inputs, assumptions, and draft output tables be provided to stakeholders in Excel format by year, as well as considering ways to make scheduling more accessible. PacifiCorp

Cadmus Group requested the conservation supply curves generated in support of the IRP. PacifiCorp provided the requested data in the feedback form response.[17]

Southwest Energy Efficiency Project and Utah Clean Energy provided a number of recommendations to update conservation potential assessments results for actual program performance. PacifiCorp requested any workpapers underlying the recommendations and engaged with parties to implement any needed changes. [18]

Oregon Public Utility Commission Staff requested additional information regarding why Direct Load Control demand response programs have not been proposed as pilots in PACW, requested information regarding why the “large project adder” was removed from the Oregon projection, and requested information on other modeling inputs. PacifiCorp responded that Direct Load Control pilots have not been identified as cost-effective in PACW, and provided other information requested as part of the stakeholder feedback form response.[19]

[13] Feedback Form 010; May 4, 2020
[14] Feedback Form 011; May 4, 2020
[15] Feedback Form 012; May 4, 2020
[16] Feedback Form 034; September 15, 2020
[17] Feedback Form 048; October 4, 2020
[18] Feedback Form 049; October 9, 2020
[19] Feedback Form 050; October 16, 2020

Washington Utilities and Transportation Commission Staff requested additional information regarding costs, total resource cost tests, and resource acquisition levels to be included in the IRP. PacifiCorp provided the requested detail in the feedback form response.[20]

Southwest Energy Efficiency Project raised questions with the energy efficiency measure results and achievable technical potential. PacifiCorp provided additional detail in the feedback form response.[21]

Consultant Reports

The Wyoming Public Service Commission asked whether/how the 2021 IRP would include the costs and reliability effects of the Kiewit decommissioning studies (including the other items to consider and contingency percentage). PacifiCorp responded that the 2021 IRP will include base estimate demolition costs from the 2019 decommissioning study for the coal-fueled generating units, will include "take-or-pay" provisions, and will not include contingency reserves as they cannot reliably be estimated at an acceptable level of granularity at this time.

Customer Preference

Sierra Club requested additional detail regarding the incremental costs or savings from customer preference resources, a list of what actions "customer preference" includes, and detail on the customer preference slides shown during the December 3, 2020 IRP public input meeting. PacifiCorp responded with the requested detail within the feedback form.[22]

Distributed Energy Resources

Washington Utilities and Transportation Commission Staff requested additional detail regarding how PacifiCorp plans for allowable levels of distributed energy resources on the system, including quantifying benefits of distributed resources. PacifiCorp held a call with Staff on December 7, 2020 to discuss the questions and provide responses.[23]

Energy Efficiency

City of Kemmerer requested a technical conference to discuss "supply-side energy efficiency" of various technology types, as well as analysis of costs and subsidies. PacifiCorp responded that resource efficiency as described in the request is roughly equivalent to levelized cost of energy per resource type, which is included in Chapter 6 of the IRP.[24]

Oregon Public Utility Commission Staff requested confirmation that there would be an opportunity to discuss bundling methodologies in accordance with Oregon Order No. 20-186. PacifiCorp addressed the topic during the October 2020 public input meeting.[25]

[20] Feedback Form 056; November 3, 2020
[21] Feedback Form 068; December 4, 2020
[22] Feedback Form 071; December 18, 2020
[23] Feedback Form 056; November 3, 2020
[24] Feedback Form.021; August 28, 2020
[25] Feedback Form 041; September 28, 2020

Oregon Public Utility Commission Staff requested additional information regarding energy efficiency bundling methodology. PacifiCorp provided information in response to the stakeholder feedback form and held a follow-up discussion as part of the January IRP public-input meeting.[26]

Washington Utilities and Transportation Commission Staff provided recommendations and requests for detail regarding energy efficiency, energy efficiency and renewable energy shaping, and load shapes. PacifiCorp responded to requests for information through the feedback form process, and recommendations for energy efficiency and renewable energy shaping will be considered in future planning cycles.[27]

Energy Storage

Utah Valley Earth Forum recommended that PacifiCorp avoid lithium batteries to facilitate development of the market for the construction of electric vehicles. PacifiCorp responded that lithium-ion batteries are the most competitive energy storage technology (as of the 2019 IRP), but that IRP modeling does not focus on specific battery chemistry. PacifiCorp has commissioned a study of cost and performance characteristics of renewable resources as well as energy storage.[28]

Renewable Northwest emphasized that co-located energy storage and renewables provided flexibility and regional grid benefits, and that co-location should be encouraged. Renewable Northwest also encouraged an independent analysis at the balancing authority level to evaluate whether battery storage systems can provide benefits for peak hours in a year. PacifiCorp replied that the company currently evaluates alternative solutions to planned transmission and distribution upgrades, and battery storage is a potential alternative.[29]

Oregon Citizen's Utility Board requested additional information regarding how battery storage will be modeled in the IRP and whether the IRP will account for interactive effects of Direct Load Control and Price-based Demand Response programs. PacifiCorp responded that battery storage is modeled on a state-by-state basis, and that Direct Load Control is taken into account. While not a direct modeling input, the effects of Price-based Demand Response programs are included in the load forecast.[30]

Oregon Public Utility Commission Staff requested additional information on the solar plus storage constraints presented during the June 2020 public input meeting, as well as whether there are any constraints that would prevent the company from adding storage capacity to variable energy resources. PacifiCorp responded to these requests and discussed how the IRP's aggregated topology eliminates the need to co-locate as long as the resources are in the same transmission bubble. A discussion of constraints was discussed in the feedback form response.[31]

Able Grid Energy Solutions provided recommendations and data to support the inclusion of energy storage in the supply-side resource table and within portfolio modeling.[32]

[26] Feedback Form 063; November 17, 2020
[27] Feedback Form 074; February 4, 2021
[28] Feedback Form 014; June 27, 2020
[29] Feedback Form 015; June 29, 2020
[30] Feedback Form 031; September 9, 2020
[31] Feedback Form 032; September 10, 2020
[32] Feedback Form 055; October 26, 2020

Environmental Policy

Powder River Basin Resource Council requested a follow-up to the October 2020 discussion on regional haze, including a discussion of what the "baseline" case is for regional haze. PacifiCorp held a follow-up discussion as part of the November 16, 2020 IRP public-input meeting.[33]

Powder River Basin Resource Council requested additional data on how risk, cost, and benefits regarding water use and water rights would be incorporated for coal-fired generation. PacifiCorp provided the additional detail requested in the feedback form response.[34]

IRP Public-Input Meeting Process/General Comments

Utah Association of Energy Users requested more detail on how the company planned to allow opportunities for stakeholder feedback, given the extension of IRP filing to September 1, 2021 and the cancellation of the May public input meetings. PacifiCorp subsequently added a public-input meeting date in August to provide greater opportunity for feedback.[35]

Derek Sawaya provided a recommendation to transition to net-zero [emitting] energy as quickly as possible. PacifiCorp considered this feedback as part of the portfolio modeling process, and the preferred portfolio shows CO2 emissions reductions of 98% from 2005 levels by 2050.[36]

Utah Office of Consumer Services recommended the inclusion of customer rate impacts analysis within the IRP. PacifiCorp analyzes the present value revenue requirement of different portfolios as part of the portfolio selection process.[37]

Legislation

Utah Association of Energy Users asked for additional detail on Oregon House Bill 2021 and how it may impact the 2021 IRP. PacifiCorp discussed HB 2021 during the July 30, 2021 IRP public-input meeting.[38]

Load Forecasting

Utah Clean Energy asked for additional information on the electric vehicle and building electrification forecasts used to estimate increased sales. PacifiCorp responded that EV growth projections are unique to each state (and provided more information as an attachment) and clarified that the building electrification projections were based on the outcome of HB 421 in Utah.[39]

Oregon Public Utility Commission Staff requested to review the company's load forecast methodology, which is included in the 2019 IRP, Appendix A. The company further responded to

[33] Feedback Form 053; October 24, 2020
[34] Feedback Form 054; October 24, 2020
[35] Feedback Form 080; May 25, 2021
[36] Feedback Form 086; August 3, 2021
[37] Feedback Form 089; August 12, 2021
[38] Feedback Form 082; June 28, 2021
[39] Feedback Form 019; August 6, 2020

Staff's request for more information on low and high private generation load forecast sensitivities, and explained that the underlying load forecast methodology underlying the IRP and Oregon Docket UE 374 (Oregon 2020 General Rate Case) is the same.[40]

Oregon Public Utility Commission Staff requested more detail on how renewable load correlation method considers differences on the west and east sides of PacifiCorp's system. PacifiCorp provided the requested detail in the feedback form response.[41]

Market Reliance Assessment

Sierra Club requested additional information regarding what types of transactions are considered as part of "market reliance," which delivery points for market purchases and sales are available on the PacifiCorp system, and any planned assessments of the overall supply and availability of market resources over time. PacifiCorp responded that market reliance assumes short-term firm front office transactions which are assumed in planning to meet capacity needs. PacifiCorp provided additional information as requested by Sierra Club as part of the stakeholder feedback form response.[42]

Washington Utilities and Transportation Commission Staff requested additional information on the market reliance assessment, including how climate change is considered and what risk analyses have been incorporated to measure market liquidity trends. PacifiCorp provided the requested detail in the feedback form response.[43]

Oregon Public Utility Commission Staff requested additional information regarding the applicability of front-office transaction limits across all hours. PacifiCorp provided the requested information as part of the feedback form response.[44]

Modeling Assumptions

The Wyoming Public Service Commission recommended modeling scenarios that consider the possibility that all Rocky Mountain Power states decline the additional load and costs within the reassignment filings. PacifiCorp responded that it would be considered for inclusion in the 2021 IRP modeling process and may also be considered through the multi-state process in advance of the reassignment filings.

Washington Utilities and Transportation Commission Staff provided recommendations for the calculation of the three required scenarios under Washington's Clean Energy Transformation Act. PacifiCorp consulted the recommendations when planning the scenario runs to comply with the legislation.[45]

[40] Feedback Form 033; September 10, 2020
[41] Feedback Form 077; April 9, 2021
[42] Feedback Form 052; October 19, 2020
[43] Feedback Form 056; November 3, 2020
[44] Feedback Form 057; November 6, 2020
[45] Feedback Form 056; November 3, 2020

Washington Utilities and Transportation Commission Staff provided a reminder that regardless of the preferred portfolio, coal-fired resources cannot be included in Washington's allocation of electricity after 2025.[46]

Natrium Demonstration Project

Sierra Club requested additional detail about the Natrium demonstration project and evaluation within the 2021 IRP. PacifiCorp responded through the stakeholder feedback form process.[47]

Western Resource Advocates requested additional detail regarding the technology involved in the Natrium demonstration project. PacifiCorp's response included the requested information.[48]

Green Energy Institute requested additional information about the project, including siting considerations and fuel considerations. PacifiCorp's response included the requested information.[49]

Natural Gas

Utah Association of Energy Users noted that natural gas price forecasts have been consistently higher than actual realized pricing since 2008 and recommended that the low-price forecast take into account the reality of flat-to-declining natural gas price futures. PacifiCorp noted that if Utah Association of Energy Users had a specific price forecast or methodology that it recommended, that PacifiCorp could include it as a potential scenario. The company otherwise will continue to rely on third-party experts to provide natural gas price forecasting due to the complexity.[50]

Operating Limits

Sierra Club requested information regarding the definition of "operating limits" including whether operating limits referred to a reduction in thermal capacity factor. PacifiCorp clarified that operating limits were plant-wide emissions limits and could be achieved through numerous measures.

Sierra Club requested information on coal operations, including what constraints PacifiCorp applies to the operation of coal units, and whether the company would consider a model run that specified all coal units retired by 2030. PacifiCorp has implemented portfolio P-02, which specifies all coal units retired by 2030.[51]

Plexos

Washington Utilities and Transportation Commission Staff requested additional information regarding how Plexos would be used for stochastic risk analysis, how loss of load probability would be incorporated into the modeling, how social cost of greenhouse gas would be

[46] Feedback Form 069; December 11, 2020
[47] Feedback Form 081; June 11, 2021
[48] Feedback Form 083; July 9, 2021
[49] Feedback Form 084; July 15, 2021
[50] Feedback Form 018; July 28, 2020
[51] Feedback Form 052, October 19, 2020

incorporated, price forecasts, and other potential risks to quantify within the model. PacifiCorp provided the requested information as part of the feedback form response.[52][53]

Oregon Administrative Hearings Division asked for additional data (production costs) that is input into the IRP for existing generators. Administrative Hearings Division further asked for explanation on how the Plexos optimization model inputs are treated. PacifiCorp clarified that production costs are an input regardless of the modeling process, and that the slides discussed during the public input meeting referred generally to linear optimization modeling (but not specifically to Plexos or the 2021 IRP).[54]

Idaho Public Utilities Commission Staff asked for additional explanation on how the Plexos optimization simulation model is validated. PacifiCorp responded that the company is performing a benchmark test of Plexos against the 2019 IRP preferred portfolio to ensure that similar results are reached given similar inputs.[55]

Washington Utilities and Transportation Commission Staff requested additional information on the Plexos modeling progress and the inclusion of the social cost of greenhouse gas for the 2021 IRP. PacifiCorp provided the requested data in the feedback form response.[56]

Western Resource Advocates requested additional information regarding how Plexos would consider certain coal analysis components (take-or-pay, fuel plans of company-owned mines, fuel cost forecasts, etc.). PacifiCorp provided the requested detail as part of the feedback form response.[57]

Utah Association of Energy Users asked if the 2020 all source request for proposals results would be incorporated into the 2021 IRP. PacifiCorp responded that results of the final short list would be included, and that the results would be discussed at the June public-input meeting.[58]

Private Generation Study

Oregon Public Utility Commission Staff requested that the private generation study outline the policy driver assumptions. PacifiCorp responded that existing regulatory structures and known incentives are used to develop the forecast, but no future regulatory/incentive regimes are assumed.[59]

Procurement

Sierra Club requested anonymized median bid price data from PacifiCorp's 2020 all source request for proposals initial short list. PacifiCorp provided the requested detail.[60]

[52] Feedback Form 056; November 3, 2020
[53] Feedback Form 065; November 25, 2020
[54] Feedback Form 016; July 23, 2020
[55] Feedback Form 051; October 22, 2020
[56] Feedback Form 074; February 4, 2021
[57] Feedback Form 079; April 27, 2021
[58] Feedback Form 080; May 25, 2021
[59] Feedback Form 041; September 28, 2020
[60] Feedback Form 071; December 18, 2020

Oregon Public Utility Commission Staff provided a reminder of Oregon's competitive bidding rules.[61]

Reliability Assessment

Wyoming Office of Consumer Advocate forwarded WECC's Western Assessment of Resource Adequacy and recommended that PacifiCorp incorporate the report's recommendations. PacifiCorp has reviewed the report and included a summary of its findings in Volume I, Chapter 5 (Reliability and Resiliency).[62]

Renewable Energy Resources

Oregon Public Utility Commission Staff asked why PacifiCorp does not compare the generation shapes of all resources to the load shape of the system – including why east and west resources were divided. PacifiCorp responded that local weather conditions are likely to drive correlation, and that west/east load and generation shapes were most closely correlated.

Utah Valley Earth Forum asked that for solar installations considered, that the company model horizontal turning panels by each panel pivoting about a vertical axis. PacifiCorp responded that single axis tracking solar photovoltaic systems were modeled in the 2019 IRP and would be modeled again in the 2021 IRP. Further, a wide range of technologies and configurations can be offered into procurement processes downstream from the IRP, as applicable.[63]

Resource Adequacy

Wyoming Office of Consumer Advocate sent the Western Electric Coordinating Council Western Assessment of Resource Adequacy report and recommended that PacifiCorp include recommendations in the 2021 IRP. PacifiCorp considered the report and recommendations within Volume I, Chapter 5 (Reliability and Resiliency).

Sensitivity Studies

The City of Kemmerer requested a sensitivity that would eliminate all hydroelectric generation from the grid and would add back coal-fueled generation. PacifiCorp responded that the requested sensitivity would be considered.[64]

The City of Kemmerer requested a sensitivity that eliminated all tax credits and subsidies are eliminated. PacifiCorp responded that the requested sensitivity would be considered.[65][66]

Wyoming Office of Consumer Advocate provided the framework for a business as usual case which would begin from the current portfolio and would quantify customer impacts that would

[61] Feedback Form 077; April 9, 2021
[62] Feedback Form 075; February 9, 2021
[63] Feedback Form 017; July 25, 2020
[64] Feedback Form 026; August 28, 2020
[65] Feedback Form 027; August 28, 2020
[66] Feedback Form 028; August 28, 2020

result from incremental changes from the portfolio. PacifiCorp incorporated this recommendation into the BAU1 and BAU2 studies.[67]

Wyoming Office of Consumer Advocate requested a sensitivity focused on system reliability throughout the summer, in light of non-resource adequacy resources being deemed as emergency capacity resources to support weather-related reliability challenges. This feedback is included in PacifiCorp's climate change scenario.[68]

Wyoming Office of Consumer Advocate requested a Wyoming House Bill 200 sensitivity as part of the 2021 IRP. PacifiCorp responded that the company would evaluate the potential impacts of the bill.[69]

Wyoming Public Service Commission Staff requested the following sensitivities[70]:

- A model run showing the PVRR with no early coal or gas retirements to compare the preferred portfolio (all other assumptions remaining the same). This is included through the company's business as usual cases.
- A model run that assumes carbon capture on all Wyoming coal plants with assumptions of CCUS with zero capital costs (assuming third party pays capital costs) and the inclusion of 45Q tax credits retained by Company. Carbon capture utilization and sequestration technology was included for analysis in the 2021 IRP.
- Rerun the IRP model without Washington Clean Energy Transformation Act (CETA) to compare against the preferred portfolio. This is included through the CETA alternative lowest reasonable cost scenario.
- Implementation of SF0159 where the Company purchases coal generation at avoided cost for all Wyoming units past the retirement date. To model how new generation needs change when coal generation in Wyoming is purchased at the Company's avoided cost.
- Various sensitivity analysis related to prolonged extreme weather events sensitivity ran on the preferred portfolio, such as: 3 days of record high temperatures and more A/C load, 3 days of record low temperatures with additional heating load, 15% reduction in solar generation due to cloudy weather paired with a 15% reduction in wind generation due to reduced wind. This is included through the company's climate change sensitivity.
- A sensitivity analysis on how electrification affects load growth and the Company's ability to meet reliability standards when EVs adoption rates increase exponentially in 2023. EV adoption and electrification cases are included in the load forecast.

Wyoming Public Utility Commission Staff provided the framework for a business as usual case. This framework informed the company's two planned business as usual scenarios.[71]

Renewable Northwest recommended that a business as usual case consider relevant state policy objectives and continue to make economic retirement decisions and the growing scale of energy

[67] Feedback Form 037; September 23, 2020
[68] Feedback Form 039; September 23, 2020
[69] Feedback Form 040; September 23, 2020
[70] Feedback Form 044; September 29, 2020
[71] Feedback Form 045; September 30, 2020

efficiency and demand response. Renewable Northwest's recommendations informed the company's two planned business as usual scenarios.[72]

Washington Utilities and Transportation Commission Staff and Oregon Public Utility Commission Staff jointly provided a set of sensitivity runs that are CETA compliant and apply a social cost of carbon cost adder. The cases informed the P01, P02, and P03 cases planned by the company, and were factored into the development of CETA required cases (such as maximum customer benefit and climate change).[73]

Wyoming Industrial Energy Consumers emailed a joint party recommendation for two business as usual cases for modeling in the 2021 IRP. PacifiCorp consulted the requested cases when building the "business as usual" portfolios.[74]

Oregon Public Utility Commission Staff requested a low market price, high volatility sensitivity to determine the optimal portfolio in a high-renewable and no-gas buildout throughout the WECC. PacifiCorp considered this request when developing portfolios.[75]

Wyoming Industrial Energy Consumers requested a stochastic sensitivity that took into account weather-related extended outage risks within the 2021 IRP. PacifiCorp included a climate-change sensitivity in the 2021 IRP that included the best available science on climate change and potential risks.[76]

Powder River Basin Resource Council, National Parks Conservation Association, and HEAL Utah requested a sensitivity that incorporates selective catalytic reduction controls at Jim Bridger units 1 and 2, Wyodak, Naughton units 1 and 2, and all 5 units at Hunter and Huntington. PacifiCorp considered this request as part of the portfolio construction process.[77]

Utah Division of Public Utilities requested an additional sensitivity to allow the model to select new proxy natural gas units as a resource option. PacifiCorp added this requested sensitivity to the portfolio modeling process as a result of this feedback.[78]

Utah Clean Energy and other parties requested an additional sensitivity to study potential retirement dates for Jim Bridger Units 3 & 4. PacifiCorp added this requested sensitivity to the portfolio modeling process as a result of this feedback.[79]

PacifiCorp included discussions on requested and required sensitivities in Chapter 7 – Portfolio Modeling and presented sensitivities as part of the August 6, 2021 IRP public-input meeting.

State Energy Policy

[72] Feedback Form 046; October 2, 2020
[73] Feedback Form 047; October 2, 2020
[74] Feedback Form 058; November 10, 2020
[75] Feedback Form 061; November 17, 2020
[76] Feedback Form 067; December 4, 2020
[77] Feedback Form 070; December 17, 2020
[78] Feedback Form 087; August 3, 2021
[79] Feedback Form 088; August 3, 2021

Washington Utilities and Transportation Commission Staff asked for additional information regarding how PacifiCorp would show compliance with the legislative requirements of RCW 19.405.030(1)(a). PacifiCorp responded that it would comply with the method directed in rule, once adopted. PacifiCorp is continuing to work with Staff and Commissioners to ensure compliance.[80]

Washington Utilities and Transportation Commission requested additional data on how key components of the Clean Energy Transformation Act – including the required Climate Change scenario – would be modeled as part of the IRP. PacifiCorp provided additional information regarding the modeling process for heating and cooling degree days, a 1-in-20 year scenario, and the availability of differing modeling timescales.[81][82]

The City of Kemmerer asked that Wyoming's Senate File 159 and House Bill 200 be included in the 2021 IRP. Both are included and have been addressed at the September 17, 2020 public input meeting.[83]

Oregon Public Utility Commission Staff recommended a preliminary House Bill 2021 assessment as part of the 2021 IRP and requested additional information/confirmation on baseline emissions. PacifiCorp will work with Staff to determine the best path forward on HB 2021 compliance.[84]

Supply-side Resource Costs/Supply-side Resource Table

The City of Kemmerer requested that small nuclear reactors be included in the supply-side table, as well as carbon capture coal technology. Both have been added to the supply-side table for 2021.[85]

The City of Kemmerer requested additional elevations to be included in the efficiency study for natural gas resources. PacifiCorp responded that the elevations currently included in the study represented a reasonable range across the system, and that specific elevations by site were not feasible for a proxy study.[86][87]

Oregon Public Utility Commission Staff asked if any potential economies of scale were potentially being missed as part of the current supply-side resource table solar selection and asked for additional information on solar and wind profiles that may be used in the IRP. PacifiCorp responded that above 200MW of solar, economies of scale are marginal. The company also provided additional detail for the solar and wind profiles.[88]

Wyoming Office of Consumer Advocate requested that carbon capture utilization and sequestration technology and small modular nuclear reactors should be included in the supply-side resource table. Both have been included for the 2021 IRP.[89]

[80] Feedback Form 013; June 26, 2020
[81] Feedback Form 013; June 26, 2020
[82] Feedback Form 020; August 7, 2020
[83] Feedback Form 024; August 28, 2020
[84] Feedback Form 090; August 9, 2021
[85] Feedback Form 022; August 28, 2020
[86] Feedback Form 023; August 28, 2020
[87] Feedback Form 035; September 17, 2020
[88] Feedback Form 033; September 10, 2020
[89] Feedback Form 038; September 23, 2020

Wyoming Public Service Commission Staff provided a number of questions and recommendations with regard to the supply-side table, price-policy scenarios, and optimization of retirement dates. PacifiCorp responded to the questions through the feedback form, and subsequently discussed optimized retirement dates as part of the portfolio discussions in June and July 2021.[90]

Wyoming Public Service Commission Staff requested that carbon capture utilization and sequestration technology be included in the supply-side resource table and asked for additional information on the 2019 supply side resource tables and underlying data. PacifiCorp included carbon capture utilization and sequestration technology in the 2021 IRP and provided the data requested through the feedback form.[91]

Oregon Public Utility Commission Staff requested that offshore wind be included in the supply-side table after the 2021 IRP. In response to this feedback, PacifiCorp included a discussion of offshore wind potential in the 2021 IRP, and plans to include off-shore wind in the 2023 IRP supply-side table.[92]

Oregon Public Utility Commission Staff requested additional information on carbon capture utilization and sequestration inputs and coal take-or-pay provisions in the supply-side resources table. PacifiCorp provided the requested information in the stakeholder feedback form response.[93][94]

Transmission

Oregon Administrative Hearings Division requested explanation of the target in-service assumptions for Gateway West Segment D1 in the 2019 IRP. PacifiCorp responded that Gateway West Segment D1 was not modeled in the 2019 IRP but is necessary to comply with FERC order and to achieve the level of new resources in eastern Wyoming included in the preferred portfolio at the end of 2023.[95]

Oregon Public Utility Commission Staff requested additional detail regarding how the Boardman to Hemingway line would be modeled in the 2021 IRP and how the upgrade/financing would be conducted. PacifiCorp provided information regarding the company’s east-to-west share of the line and the asset swap agreement but had not yet determined the modeling approach for the line.[96]

Western Resource Advocates requested that once the transmission topology was complete, that PacifiCorp provide the incremental transmission capacity as compared to the 2019 IRP. Discussion of transmission capacity is included in Chapter 4 – Transmission, Chapter 7 – Portfolio Modeling, and Chapter 8 – Portfolio Selection.[97]

[90] Feedback Form 042; September 29, 2020
[91] Feedback Form 043; September 29, 2020
[92] Feedback Form 073; January 19, 2021
[93] Feedback Form 073; January 19, 2021
[94] Feedback Form 077; April 9, 2021
[95] Feedback Form 016; July 23, 2020
[96] Feedback Form 029; September 3, 2020
[97] Feedback Form 060; November 17, 2020

Interwest Energy Alliance requested additional detail on when network service transmission capacity from retiring assets is made available for interconnection – including more information on the process and notification to transmission customers. PacifiCorp provided the requested detail in the feedback form response.[98] Interwest further requested information on legal needed for approval of the 2021 IRP projects, import capacity assumed, and requested additional clarity on how transmission projects were selected.[99]

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

Phone Number:
(503) 813-5245

[98] Feedback Form 064; November 25, 2020
[99] Feedback Form 091; August 4, 2021

APPENDIX D – DEMAND-SIDE MANAGEMENT RESOURCES

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 2021 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 2021-2040

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 2021-2040,[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 2021 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

[1] PacifiCorp's Demand-Side Resource Potential Assessment for 2021-2040, completed by AEG, can be found at: www.pacificorp.com/energy/integrated-resource-plan/support.html.

involuntary in that, once equipment and systems have been put in place, savings can be expected to occur over a certain period of time. DSR and behavioral-based activities involve greater customer choice and control. This assessment estimates potential from demand response, energy efficiency, and DSR.

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

Current DSM Program Offerings by State

Currently, PacifiCorp offers a robust portfolio of DSM programs and initiatives, most of which are offered in multiple states, depending on size of the opportunity and the need. Programs are reassessed on a regular basis. PacifiCorp has the most up-to-date programs on its website.[2] Demand response and energy efficiency program services and offerings are available by state and sector. Energy efficiency services listed for Oregon, except for low-income weatherization services, are provided in collaboration with Energy Trust of Oregon.[3]

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

PacifiCorp has numerous DSR offerings currently available. They include metered time-of-day and time-of-use pricing plans (in all states, availability varies by customer class), and residential seasonal rates (Idaho and Utah). System-wide, approximately 17,200 customers were participating in metered time-of-day and time-of-use programs as of December 31, 2019.

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 ***watt***smart 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		√	√		√	
Energy Saving Kits				√	√	√
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		√		√	√	
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.

California

On January 13, 2021, the Commission issued Decision 20-11-032, approving the company's Annual Budget Advice Letter (ABAL) Filing 637E to continue administering its energy efficiency programs through 2021. PacifiCorp submitted 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 2021 IRP preferred portfolio.

Table D.3 –First Year Demand Response Resource Selections (2021 IRP Preferred Portfolio)[4]

State/Product Category by Year (MW)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
DR Summer - ID	-	-	0.5	9.5	1.9	0.5	1.3	4.3	5.9	2.0
DR Summer - UT	-	-	29.4	26.4	7.6	3.5	5.5	9.9	9.2	8.0
DR Summer - WY	-	-	0.9	1.1	0.8	0.6	0.9	1.0	0.9	0.8
DR Winter - ID	-	-	0.5	0.9	0.3	0.5	1.2	1.8	1.9	2.0
DR Winter - UT	-	-	35.5	41.2	2.6	2.7	3.9	5.9	9.7	7.0
DR Winter - WY	-	-	0.2	0.6	0.4	0.6	0.7	0.9	0.9	0.9
RFP DR - ID	-	5.0	6.4	2.8	2.8	2.8	2.8	2.8	2.8	2.8
RFP DR - UT	-	54.7	59.3	9.1	9.1	9.1	9.1	9.1	9.1	9.1
RFP DR - WY	-	17.0	2.0	2.7	2.7	2.7	2.7	2.7	2.7	2.7
DR Summer - CA	-	-	1.1	2.0	0.5	0.4	0.5	0.7	0.6	0.7
DR Summer - OR	-	-	15.9	16.4	5.9	5.1	7.1	8.3	2.3	8.4
DR Summer - WA	-	-	3.9	4.9	2.0	1.1	1.8	2.2	1.5	1.4
DR Winter - CA	-	-	1.1	1.4	0.4	0.3	0.4	0.6	0.6	0.7
DR Winter - OR	-	-	13.7	15.4	2.8	3.1	3.2	4.3	4.3	4.7
DR Winter - WA	-	-	2.8	3.7	0.6	0.7	0.8	0.9	1.0	0.8
RFP DR - CA	-	1.8	2.1	0.6	0.6	0.6	0.6	0.6	0.6	0.6
RFP DR - OR	-	33.9	48.0	28.8	24.5	18.9	18.0	18.2	18.9	19.5
RFP DR - WA	-	11.0	19.2	16.2	13.3	10.3	8.5	6.1	5.3	5.3
Total by Year	**0**	**123.41**	**242.39**	**183.61**	**78.83**	**63.46**	**68.98**	**80.18**	**77.84**	**77.50**

[4] A portion of cost-effective demand response resources identified in the 2021 preferred portfolio are expected to be acquired through a previously issued demand response RFP soliciting resources identified in the 2019 IRP. PacifiCorp will pursue all cost-effective demand response resources identified as incremental to resources subsequently procured under the previously issued RFP in compliance with state level procurement requirements.

State/Product Category by Year (MW)	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	Total MW
DR Summer - ID	2.4	2.1	2.7	2.3	14.6	2.0	2.6	4.7	3.4	4.6	67.0
DR Summer - UT	9.9	11.1	104.8	19.7	29.7	29.5	66.3	33.8	28.6	42.3	475.0
DR Summer - WY	1.0	1.0	1.9	1.1	1.0	1.4	1.2	1.4	3.7	36.5	57.0
DR Winter - ID	1.8	2.1	3.5	2.3	2.4	2.0	2.6	2.1	7.1	7.7	42.7
DR Winter - UT	8.3	12.1	72.6	22.2	24.1	33.9	58.9	24.0	26.6	74.2	465.3
DR Winter - WY	1.0	1.0	2.8	1.1	1.0	1.4	1.1	1.4	5.9	30.2	51.7
RFP DR - ID	2.8	-	-	-	-	-	-	-	-	-	33.6
RFP DR - UT	9.1	-	-	-	-	-	-	-	-	-	186.5
RFP DR - WY	2.7	-	-	-	-	-	-	-	-	-	40.8
DR Summer - CA	0.8	0.9	1.0	0.7	1.3	1.0	2.0	3.5	2.3	3.2	23.0
DR Summer - OR	8.4	9.9	13.8	8.9	25.8	11.0	9.9	25.1	13.1	52.6	248.0
DR Summer - WA	1.8	0.6	2.2	1.1	4.3	14.3	6.2	2.6	2.2	1.2	55.3
DR Winter - CA	0.7	0.9	0.9	0.7	1.2	1.0	2.0	7.6	2.2	3.3	25.9
DR Winter - OR	5.0	7.8	6.0	9.9	43.7	15.4	9.4	51.3	11.2	44.7	255.8
DR Winter - WA	0.6	0.9	0.6	0.5	11.4	12.3	21.5	1.2	1.4	1.1	62.9
RFP DR - CA	0.6	-	-	-	-	-	-	-	-	-	8.7
RFP DR - OR	20.2	-	-	-	-	-	-	-	-	-	248.9
RFP DR - WA	5.2	-	-	-	-	-	-	-	-	-	100.4
Total by Year	**82.26**	**50.10**	**212.64**	**70.31**	**160.37**	**125.23**	**183.45**	**158.65**	**107.60**	**301.50**	**2448.30**

Table D.4 – First Year Energy Efficiency Resource Selections (2021 IRP Preferred Portfolio)

Energy Efficiency Energy (1st Year Savings MWh) Selected by State and Year										
State	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
CA	2,272	2,621	1,702	2,055	2,412	2,863	3,415	4,488	4,791	4,571
OR	174,321	141,069	124,676	123,006	118,508	126,414	131,318	136,237	145,519	145,561
WA	41,184	34,003	37,231	39,530	45,254	50,201	53,928	55,500	55,259	55,204
UT	230,790	257,465	266,500	271,227	298,181	286,714	306,600	316,691	316,193	342,228
ID	17,590	12,824	12,000	12,512	15,102	17,289	19,353	20,682	22,741	23,669
WY	43,877	44,467	44,204	80,727	83,706	88,708	94,174	96,827	94,700	94,876
Total System	510,034	492,450	486,314	529,058	563,163	572,189	608,788	630,425	639,204	666,108

Energy Efficiency Energy (1st Year Savings MWh) Selected by State and Year										
State	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
CA	3,995	4,339	3,849	3,414	2,968	3,261	3,780	3,304	3,332	3,124
OR	141,456	137,369	127,089	119,104	103,538	98,182	88,424	98,235	101,704	93,476
WA	52,754	47,873	42,479	37,700	33,324	26,190	24,150	21,300	19,555	17,219
UT	327,804	307,520	279,091	256,780	234,795	198,053	200,602	193,179	189,052	200,875
ID	22,897	21,643	20,077	18,466	17,391	14,208	13,228	12,732	11,518	11,123
WY	85,470	75,314	63,065	55,559	47,916	35,267	30,062	27,784	25,797	27,026
Total System	634,375	594,059	535,650	491,023	439,932	375,161	360,245	356,534	350,958	352,843

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).

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, the communications network is often the most critical infrastructure decision. This network must have relevant speed, reliability, and security and be scalable to support the entire service territory and interoperable for many device types, manufacturers, and generations of technology.

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 is able to 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 on line-loading calculations given a set of worst-case weather assumptions, such as high ambient temperatures and very low wind speeds. Dynamic line rating allows an increase in current-carrying capacity when more favorable weather conditions are present, and the transmission path is not constrained by other operating elements. 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 TOT4A transmission corridor and had been one of the limits of the corridor power transfer. As a result of this project, the TOT4A Western Electricity Coordinating Council (WECC) non-simultaneous path rating was increased. The DLR system on the Platte – Standpipe 230 kV line is currently being upgraded with a Transmission Line Monitoring (TLM) system manufactured by Lindsay Industries, which has been put in-service in January 2021.

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.2 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. Installation of the communications and data transfer systems between the individual PMUs and the PDC is underway and planned for completion by the end of 2021. Additionally, transient DFR data can be downloaded manually at substations.

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. Creation of a documented process to validate data 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 (CAISO)'s 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. While the automation scheme's effectiveness was able to be validated, persistent issues with the security and reliability of the piloted communication technology occurred throughout 2020 and resulted in exploring alternate technology. 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.

Wildfire Mitigation

In response to concerns of wildfire danger to customers, PacifiCorp began developing communication systems and practices to improve system reliability in at risk areas. Selected substations in Siskiyou County, California and Wasatch County, Utah are preliminary sites that will have remote communication installed to allow dispatch operators to modify re-closer settings.

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.

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.

In 2020, PacifiCorp developed Community Resiliency programs in Oregon and California to expand customer 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. In the future, the Company will evaluate opportunities to develop programs and partner with facilities that move forward with the installation of ESS infrastructure.

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 is currently at the early stages of reviewing those proposals. The Company has used the responses to incorporate the cost of Demand Response programs more accurately in the 2021 Integrated Resource Plan.

Dispatchable Customer Resources

PacifiCorp partnered with a developer in 2018 to make an innovative solar and battery solution possible at a 600-unit multi-family community in Utah. Known as Soleil Lofts, this project provides a unique opportunity for the company to implement an innovative solution using solar and battery storage integration along with demand response and advanced management of the grid through daily energy load shaping. The project includes the development of a company-owned utility data and dispatch portal with direct access to 621 Sonnen batteries, each rated at 8kW, for a total of 4.8 MWs of capacity and 12 MWh of energy within the project area. In addition to the cost savings with leveraging the Soleil community partnership, the project creates opportunity to develop and test new programs related demand response, load shaping and rate design.

At this time, approximately 450 of the 600 units have been deployed. PacifiCorp has integrated the control system into the energy management system and continues to test different use cases for the aggregated capacity.

In learning from Rocky Mountain Power's partnership with Soleil Lofts. The Company developed the Wattsmart Battery Program which was approved in October 2020 through the Utah Public Service Commission. This innovative demand response program allows Rocky Mountain Power to control behind the meter customer batteries. The Company will have the ability to control customer batteries for 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.

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 on a daily basis. 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 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.

The project is expected to be completed by the end of 2022. 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. 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.

In Utah, PacifiCorp has initiated a project to enhance the ability to receive outage notifications from intelligent line sensors, smart meters and existing AMR meters. The intelligent line sensors will be installed on distribution circuits that will provide service to critical facilities. For the purpose of 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 expected to be completed by 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

The 2021 Flexible Reserve Study (FRS) estimates the regulation reserve required to maintain PacifiCorp's system reliability and comply with North American Electric Reliability Corporation (NERC) reliability standards as well as the incremental cost of this regulation reserve. The FRS also compares PacifiCorp's overall operating reserve requirements, including both regulation reserve and contingency reserve, to its flexible resource supply over the Integrated Resource Plan (IRP) study period.

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,[1] as well as the amount of contingency reserve required to comply with NERC standard BAL-002-WECC-2.[2] BAL-001-2 is a regulation reserve standard that became effective July 1, 2016, and BAL-002-WECC-2a is a contingency reserve standard that became effective January 24, 2017. 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."[3]

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[4] (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

1 NERC Standard BAL-001-2, www.nerc.com/files/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.

2 NERC Standard BAL-002-WECC-2a, www.nerc.com/files/BAL-002-WECC-2a.pdf, which became effective January 24, 2017. BAL-002-WECC-2a clarified that non-traditional resources can qualify as spinning reserves if they meet technical and performance requirements.

3 NERC Glossary of Terms: www.nerc.com/files/glossary_of_terms.pdf, updated May 13, 2019.

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

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 as a result 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 similar to that employed in PacifiCorp's 2019 IRP but has been enhanced in two areas.[5] 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.

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

[5] 2019 Flexible Reserve Study, Appendix F in Volume II of PacifiCorp's 2019 IRP report: https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019_IRP_Volume_II_Appendices_A-L.pdf

reserve resources to cover variations in load, wind, solar, and Non-VERs. A comparison of the results of the current analysis and that from the 2019 IRP 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 IRP)	2,750	1,021	994	47%	531
2018-2019 (2021 IRP)	2,745	1,080	1,057	49%	540

Table F.2 - 2021 FRS Flexible Resource Costs as Compared to 2019 Costs, $/MWh

	Wind 2019 FRS (2018$)	Solar 2019 FRS (2018$)	Wind 2021 FRS (2020$)	Solar 2021 FRS (2020$)
Study Period	2018-2036	2018-2036	2023-2040	2023-2040
Flexible Resource Cost	$1.11	$0.85	$1.30	$1.09

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-2a.[6] Regulation reserve is capacity that PacifiCorp holds available to ensure compliance with the NERC Control Performance Criteria in BAL-001-2.[7] Frequency response reserve is capacity that PacifiCorp holds available to ensure compliance with NERC standard BAL-003-1.[8] 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-2a 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.

[6] NERC Standard BAL-002-WECC-2a – Contingency Reserve: www.nerc.com/files/BAL-002-WECC-2a.pdf
[7] NERC Standard BAL-001-2 – Real Power Balancing Control Performance: www.nerc.com/files/BAL-001-2.pdf
[8] NERC Standard BAL-003-1 — Frequency Response and Frequency Bias Setting: www.nerc.com/pa/Stand/Reliability%20Standards/BAL-003-1.pdf

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. In accordance with Requirement 2 of BAL-002-WECC-2a, at least half of a BAA's requirement must be met with "spinning" resources that are online and immediately responsive to system frequency deviations, while the remainder can come from "non-spinning" resources that do not respond immediately, though they must still be fully deployed in ten minutes.[9]

Regulation Reserve

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

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

In addition, Requirement 1 of BAL-001-2 specifies that PacifiCorp's Control Performance Standard 1 ("CPS1") score must be greater than equal to 100 percent for each preceding 12 consecutive calendar month period, evaluated monthly. The CPS1 score compares PacifiCorp's ACE with interconnection frequency during each clock minute. A higher score indicates PacifiCorp's ACE is helping interconnection frequency, while a lower score indicates it is hurting interconnection frequency. Because CPS1 is averaged and evaluated 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. 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 on in the study.

[9] Retirement of the minimum spinning reserve obligation in BAL-002-WECC-2a is being considered due to redundancy with frequency response obligations under BAL-003-1. More information is available online at: www.wecc.org/Standards/Pages/WECC-0115.aspx

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. In order to continue providing flexible capacity in the following hour, energy must be available in storage for that hour as well. The likelihood of actually 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-003-1 specifies that each BAA must arrest frequency deviations and support the interconnection when frequency drops below the scheduled level. When a frequency drop occurs as a result 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 2020 frequency response obligation was 19.4 MW/0.1Hz for PACW, and 49.1 MW/0.1Hz for PACE.[10] PacifiCorp's combined obligation amounts to 68.5 MW for a frequency drop of 0.1 Hz, or 205.5 MW for a frequency drop of 0.3 Hz.

The performance measurement for contingency reserve under the Disturbance Control Standard (BAL-002-3)[11], 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

[10] NERC. 2020 Frequency Bias Settings Effective 6/2/2020: www.nerc.com/comm/OC/Documents/BAL-003_Frequency_Bias_Settings_02Jun2020.pdf
[11] NERC Standard BAL-002-3 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event: www.nerc.com/pa/Stand/Reliability Standards/BAL-002-3.pdf

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 are capable of supporting grid restoration in PACE. PacifiCorp has not identified any incremental needs for black start service during the IRP study period.

Ancillary Services Operational Distinctions

In actual operations, PacifiCorp identifies two types of flexible capacity as part of its participation in the EIM. The contingency reserve held on each resource is specifically identified and is not available for economic dispatch within the EIM. Any remaining flexible capacity on participating resources that is not designated as contingency reserve can be economically dispatched in EIM based on its operating cost (i.e. bid) and system requirements and can contribute to meeting regulation reserve obligations. Because of this distinction, resources must either be designated as contingency reserve or as regulation reserve. Contingency events are relatively rare while opportunities to deploy additional regulation reserve in EIM occur frequently. As a result, PacifiCorp typically schedules its lowest-cost flexible resources to serve its load and blocks off 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. In order 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 in order 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.[12]

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 of its transmission customers pursuant to the provisions of Attachment T to PacifiCorp's Federal Energy Regulatory Commission (FERC) approved Open Access Transmission Tariff (OATT). This includes EIM base schedule data (or forecasts) from all resources included in the EIM network model at transaction points. EIM base schedules are submitted by transmission customers with hourly granularity, and are settled using hourly data for load, and fifteen-minute and five-minute data for resources. A primary function of the EIM is to measure load and resource imbalance (or deviations) as the difference between the hourly base schedule and the actual metered values.

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

[12] 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

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 the majority of 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.[13] 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*."[14] 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

[13] Order No. 764 at P 281; Order No. 764-B at P 210.
[14] Order No. 764 at P 20 (emphasis added).

suggested that many of its rules were developed with Non-VERs in mind and that such generation "could be scheduled with relative precision."[15] The output of these resources is largely in the control of the resource operator, particularly when considered within the hourly timeframe of the FRS. The deviations by resources in the Non-VER class are thus significantly lower than the deviations by resources in the wind class. The Non-VER class includes third-party resources (OATT or legacy transmission customers); many PacifiCorp-owned resources; and other PacifiCorp-contracted resources, such as qualifying facilities, power purchases, and exchanges. In total, the FRS includes 2,202 megawatts of Non-VERs.

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

Regulation Reserve Data Analysis and Adjustment

Overview

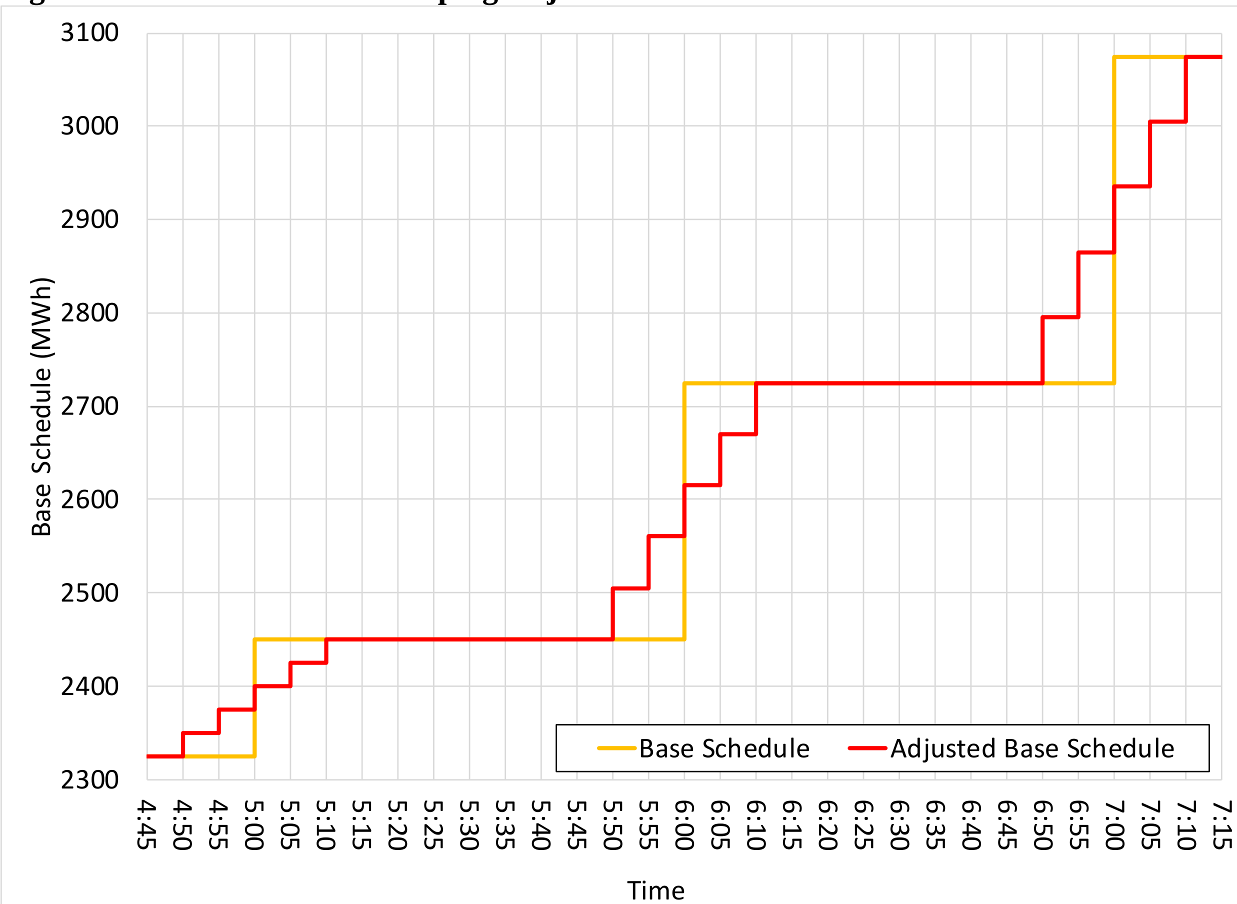
This section provides details on adjustments made to the data to align the ACE calculation with actual operations, and address data issues.

Base Schedule Ramping Adjustment

In actual operations, PacifiCorp's ACE calculation includes a linear ramp from the base schedule in one hour to the base schedule in the next hour, starting ten-minutes before the hour and continuing until ten-minutes past the hour. The hourly base schedules used in the study are adjusted 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.

[15] *Id.* at P 92.

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 back 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.[16]

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 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.[17] 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:

[16] *See* footnote 12 above for explanation of PacifiCorp's use of the T-40 base schedule time point in the FRS.
[17] NERC Standard BAL-001-2, www.nerc.com/files/BAL-001-2.pdf

> *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 has experience operating under the new standard, even though it did not become effective until July 1, 2016.

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

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

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

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

Planning Reliability Target: Loss of Load Probability

When conducting resource planning, it is common to use a reliability target that assumes a specified loss of load probability (LOLP). In effect, this is a plan to curtail firm load in rare circumstances, rather than acquiring resources for extremely unlikely events. The reliability target balances the cost of additional capacity against the benefit of incrementally more reliable operation. By planning to curtail firm load in the rare event of a regulation reserve shortage, PacifiCorp can maintain the required 100 percent compliance with the BAL-001-2 standard and the Balancing Authority ACE Limit. This balances the cost of holding additional regulation reserve against the likelihood of regulation reserve shortage events.

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

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

Balancing Authority ACE Limit: Allowed Deviations

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

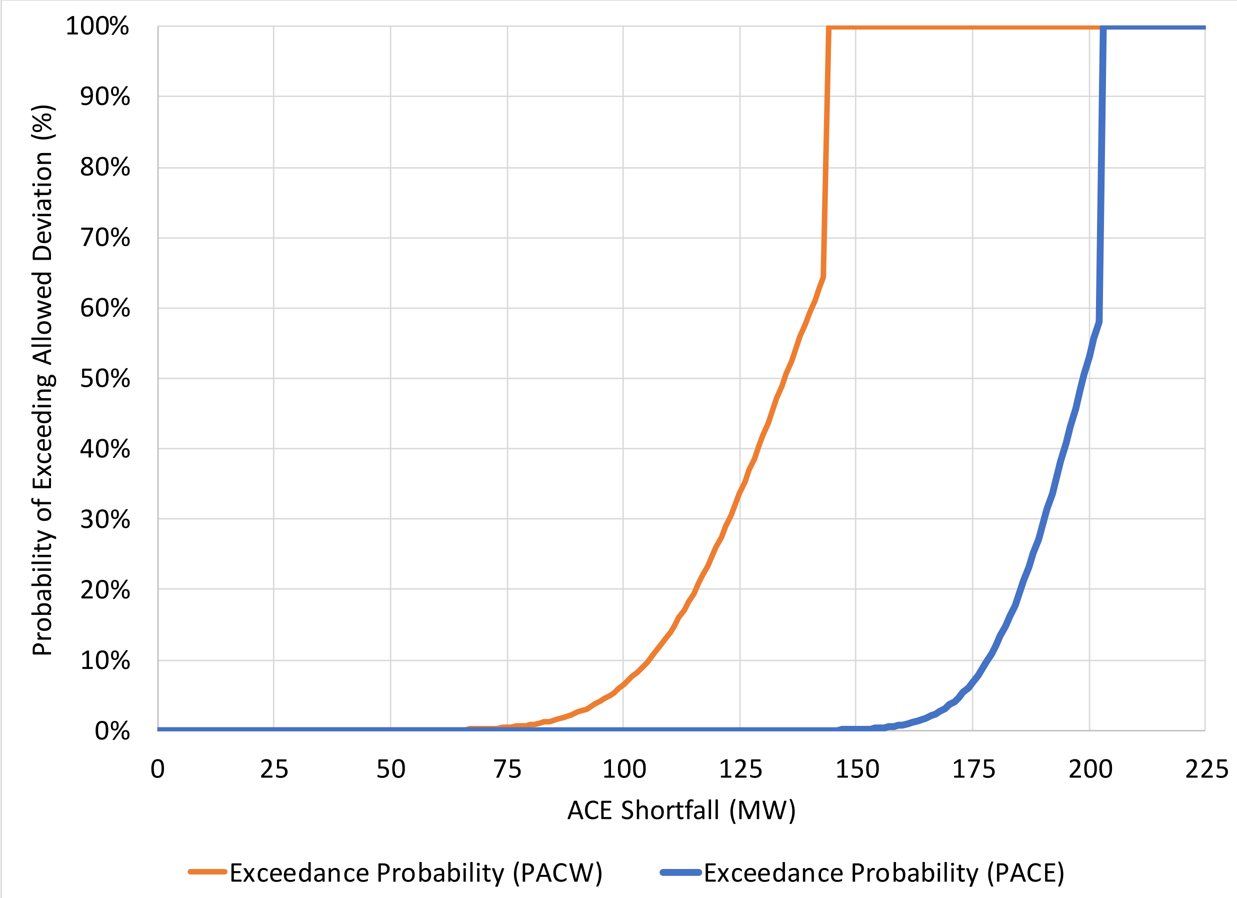
The Balancing Authority ACE Limit is specific to each BAA and is dynamic, varying as a function of interconnection frequency. When WECC frequency is close to 60 Hz, the Balancing Authority ACE Limit is large and large deviations in ACE are allowed. As WECC frequency drops further and further below 60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

While the specific Balancing Authority ACE Limit for a given interval cannot be known in advance, the historical probability distribution of Balancing Authority ACE Limit values is known. Figure F.2 below shows the probability of exceeding the allowed deviation during a five-minute interval for a given level of ACE shortfall. For instance, an 82 MW ACE shortfall in PACW has a one percent chance of exceeding the Balancing Authority ACE Limit. WECC-wide frequency can change rapidly and without notice, and this causes large changes in the Balancing Authority ACE Limit over short time frames. Maintaining ACE within the Balancing Authority ACE Limit under those circumstances can require rapid deployment of large amounts of operating reserve. To limit the size and speed of resource deployment necessitated by variation in the Balancing Authority ACE Limit, PacifiCorp's operating practice caps permissible ACE at the lesser of the Balancing Authority ACE Limit or four times L_{10}. This also limits the occurrence of transmission flows that exceed path ratings as result of large variations in ACE.[18,19] This cap is reflected in Figure F.2.

[18] "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

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

Figure F.2 - Probability of Exceeding Allowed Deviation



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

Regulation Reserve Forecast: Amount Held

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

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

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

Load Error: Load 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 on 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

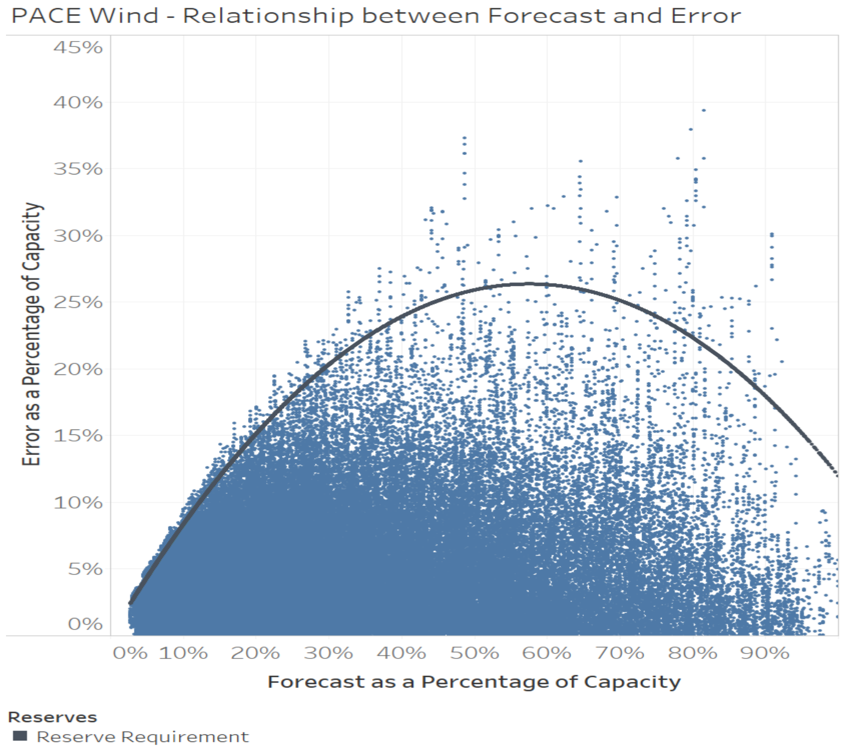


Figure F.4 - Wind Regulation Reserve Requirements by Forecast Capacity Factor - PACW

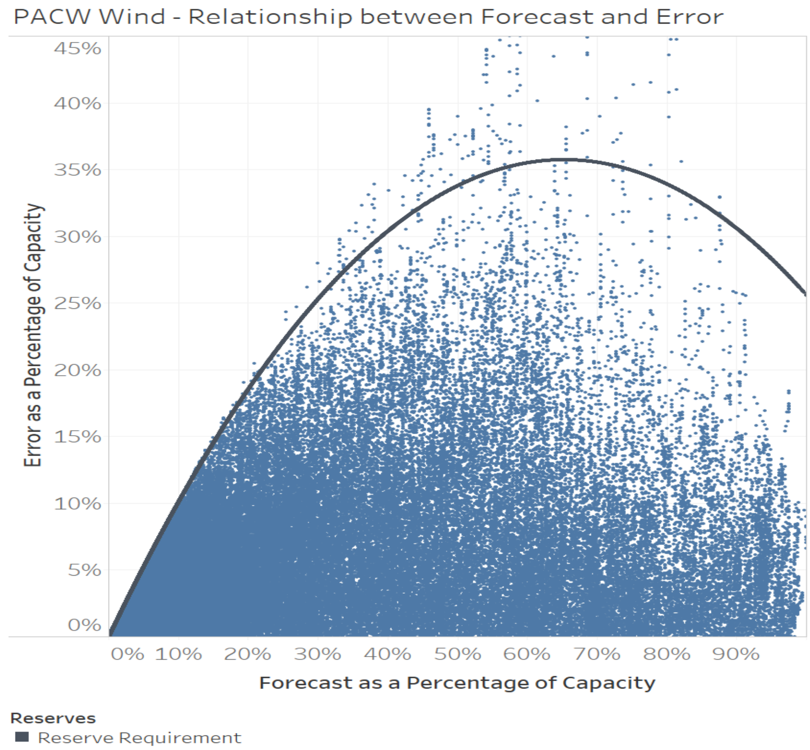


Figure F.5 - Solar Regulation Reserve Requirements by Forecast Capacity Factor - PACE

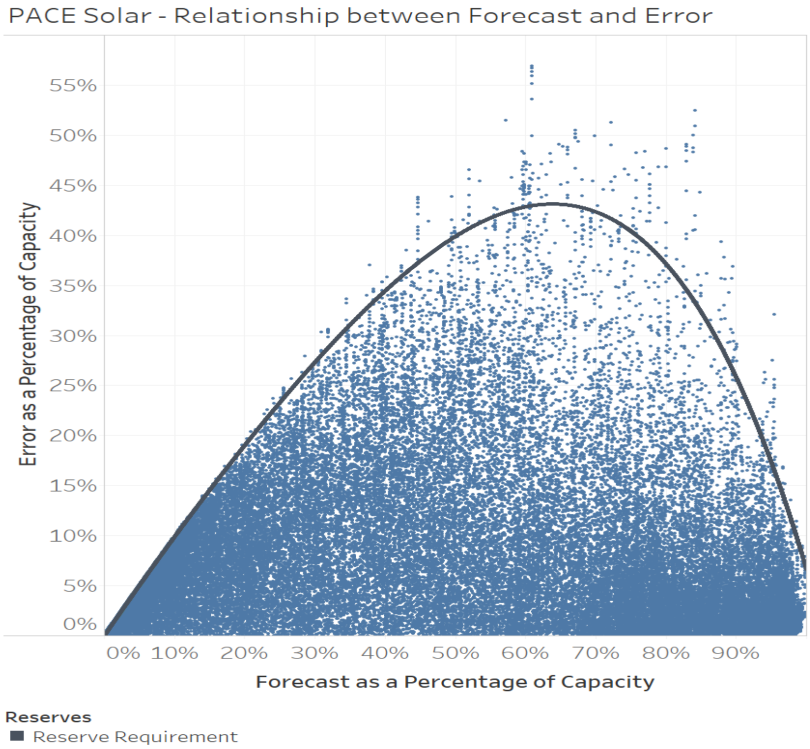


Figure F.6 - Solar Regulation Reserve Requirements by Forecast Capacity Factor - PACW

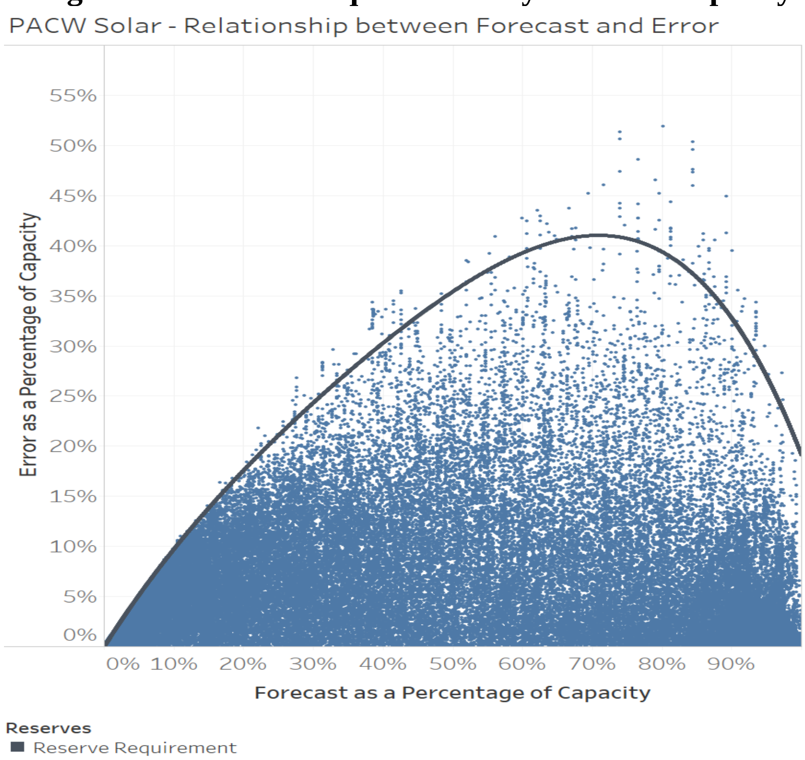


Figure F.7 – Non-VER Regulation Reserve Requirements by Capacity Factor - PACE

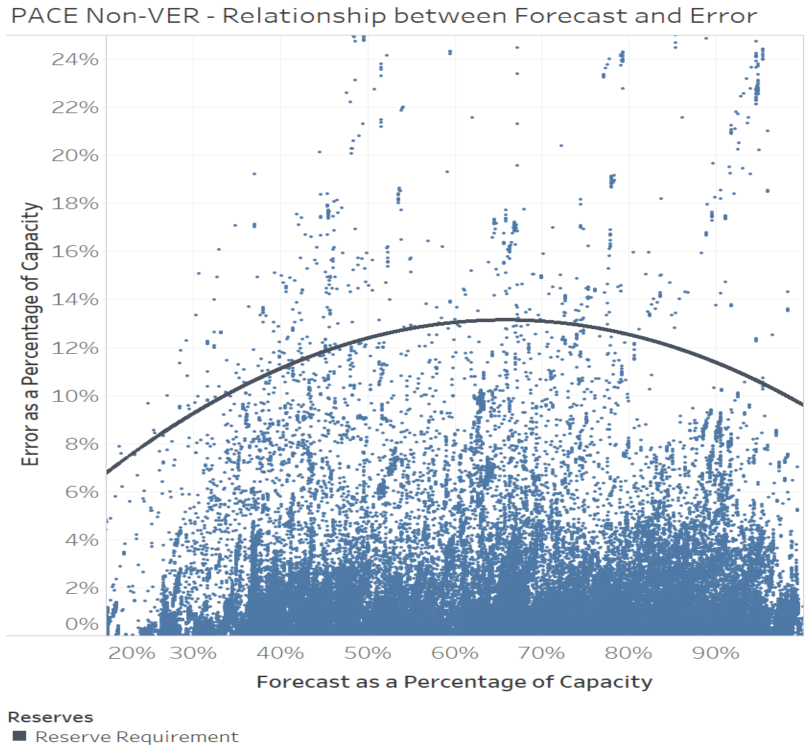


Figure F.8 – Non-VER Regulation Reserve Requirements by Capacity Factor - PACW

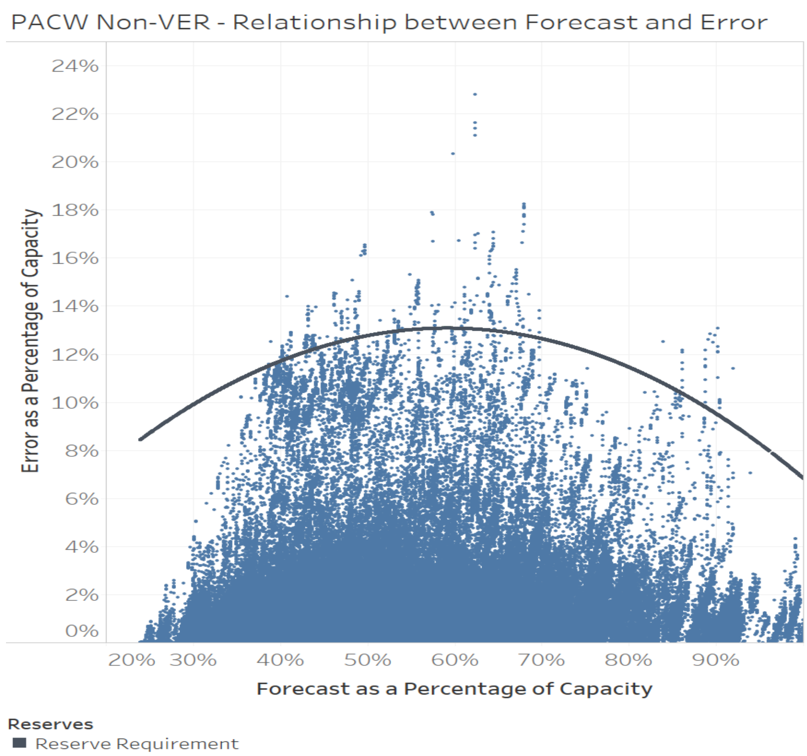


Figure F.9 – Stand-alone Load Regulation Reserve Requirements - PACE

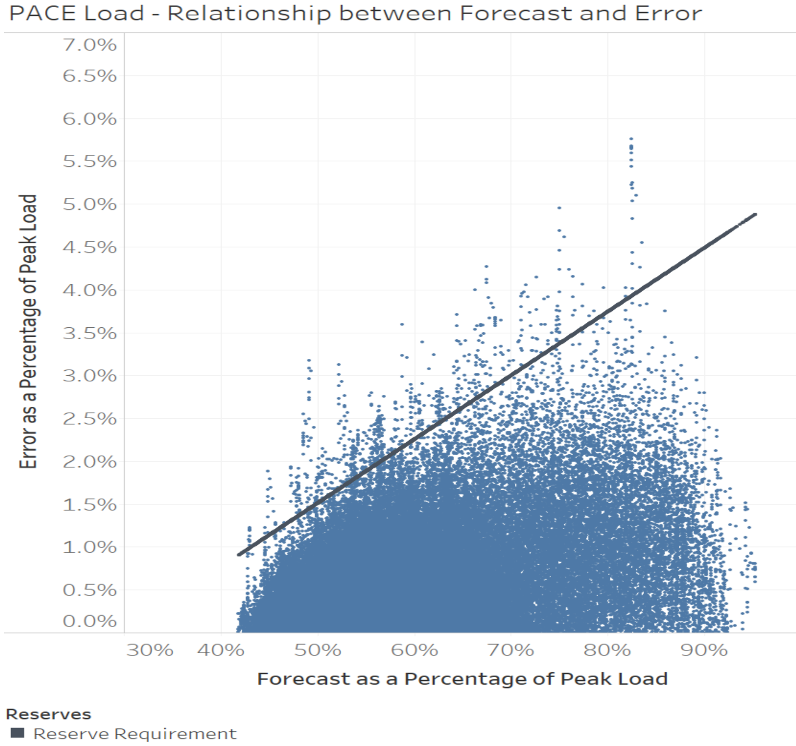
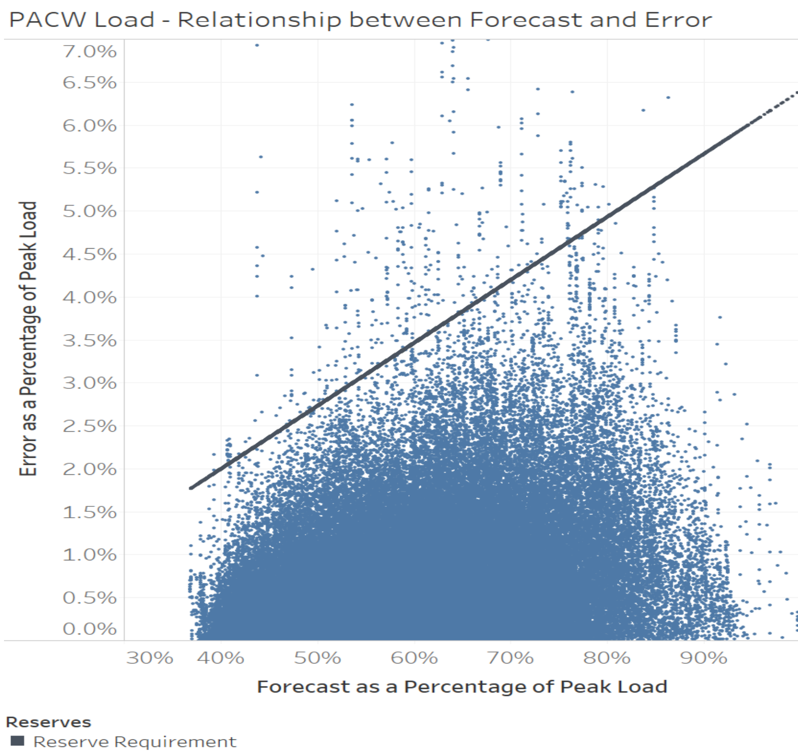


Figure F.10 – Stand-alone Load Regulation Reserve Requirements - PACW



The results of the analysis are shown in Figure 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. A number of 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, as a result 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 the majority of 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 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. 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 as a whole 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-003-1, based on median response during the largest events.

In light of the overlaps with BAL-001-2 Requirement 2 and BAL-003-1 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 2019 FRS evaluated the change in regulation reserve requirements associated with cumulatively stacking the individual wind and solar facilities throughout the two BAAs. Under this methodology as each MW of VERs is added to the system the rate of increase of the regulation reserve requirement was quantified and used to extrapolate portfolio regulation results for larger quantities of VERs. While extrapolating beyond existing data could be reasonable to a certain extent, significant wind and solar capacity additions have already been committed and have entered service since 2019 or will enter service in the next few years, and very large amounts of wind and solar additions were identified in future years in the 2019 IRP portfolio, as shown in Table F.6. Given the magnitude of the increases, the trendlines used in the 2019 FRS may not adequately represent aggregate reserve requirements.

Table F.6 – Pending and Projected Wind and Solar Capacity Additions

Case	Wind Capacity (MW)	Solar Capacity (MW)	Wind Increase (%)	Solar Increase (%)
2018-2019 (Actual)	2,745	1,080		
Actual + Signed contracts through 12/31/21	4,312	1,937	+57%	+79%
Actual + Signed contracts through 12/31/23	4,312	2,427	+57%	+125%
Actual + Signed + 19IRP Pref. Port 2024	6,232	4,581	+127%	+324%
Actual + Signed + 19IRP Pref. Port 2030	7,282	5,440	+165%	+404%

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: wind mostly in eastern Wyoming and solar mostly in southern Utah and southern Oregon. The trendline analysis performed in the 2019 FRS assumed that incremental resources continue to provide increasing levels of diversity; however, future resources added in close proximity to existing resources are likely to have lower than average diversity for that class of resources. 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 assumed in the 2019 FRS. With that in mind, the incremental regulation reserve analysis for the

2021 FRS 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 as a whole, so it is appropriate that they vary with the portfolio. To that end, for the 2021 FRS PacifiCorp has calculated 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 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 in excess of 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.7.

Table F.7 – 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.8 and Table F.9 for PacifiCorp East and PacifiCorp West, respectively.

Table F.8 – PacifiCorp East Diversity by Portfolio Composition

(% Reduction vs. Stand-alone Requirements)

East Wind Capacity MW	%								
8,224	548%	17.2%	18.8%	20.6%					*Not enough interconnection*
7,184	472%	19.2%	21.5%	23.0%	25.5%	26.5%			*capacity in 2021 IRP*
6,144	395%	22.9%	24.1%	25.6%	27.9%	28.5%	29.0%		*to reach*
5,104	319%	26.0%	27.3%	29.2%	30.7%	30.7%	30.5%	29.5%	*these*
4,064	242%	30.4%	31.6%	32.9%	33.8%	32.7%	32.8%	32.8%	*levels*
3,024	166%	35.0%	36.2%	38.5%	37.1%	37.6%	36.2%	33.9%	31.9%
1,575	100%		**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 %	**50%**	**100%**	**166%**	**329%**	**493%**	**656%**	**820%**	**983%**
	MW	**428**	**855**	**1,462**	**2,502**	**3,542**	**4,582**	**5,622**	**6,662**

2018-2019 Actual Wind and Solar Capacity (boxed cell: 48.0%)

Table F.9 – PacifiCorp West Diversity by Portfolio Composition

(% Reduction vs. Stand-alone Requirements)

West Wind Capacity MW	%								
4,389	548%	21.1%	22.4%	22.9%				*Not enough interconnection*
3,669	472%	23.4%	24.8%	25.4%	29.0%	33.0%		*capacity in 2021 IRP*
2,949	395%	26.2%	26.7%	27.6%	32.1%	34.8%	38.1%	*to reach*
2,229	319%	29.6%	30.6%	31.4%	36.2%	39.5%	42.7%	42.7%	*these*
1,509	242%	33.8%	34.5%	36.3%	40.8%	45.2%	46.2%	43.9%	*levels*

789	**166%**	38.8%	41.6%	43.1%	47.6%	48.4%	47.7%	45.0%	44.3%	
726	**100%**		$\boxed{42.4\%}$	42.9%	48.6%	49.3%	47.7%	46.2%	44.4%	
363	**50%**			41.7%	47.1%	49.8%	47.4%	45.0%	43.2%	
		50%	**100%**	**166%**	**329%**	**493%**	**656%**	**820%**	**983%**	**%**
		111	**221**	**321**	**1,041**	**1,761**	**2,481**	**3,201**	**3,921**	**MW**

West Solar Capacity

$\boxed{}$ 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.8 and F.9. 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 from the 2021 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 P02-MM portfolio. Hourly regulation reserve prices were reported from this study.

Wind Integration

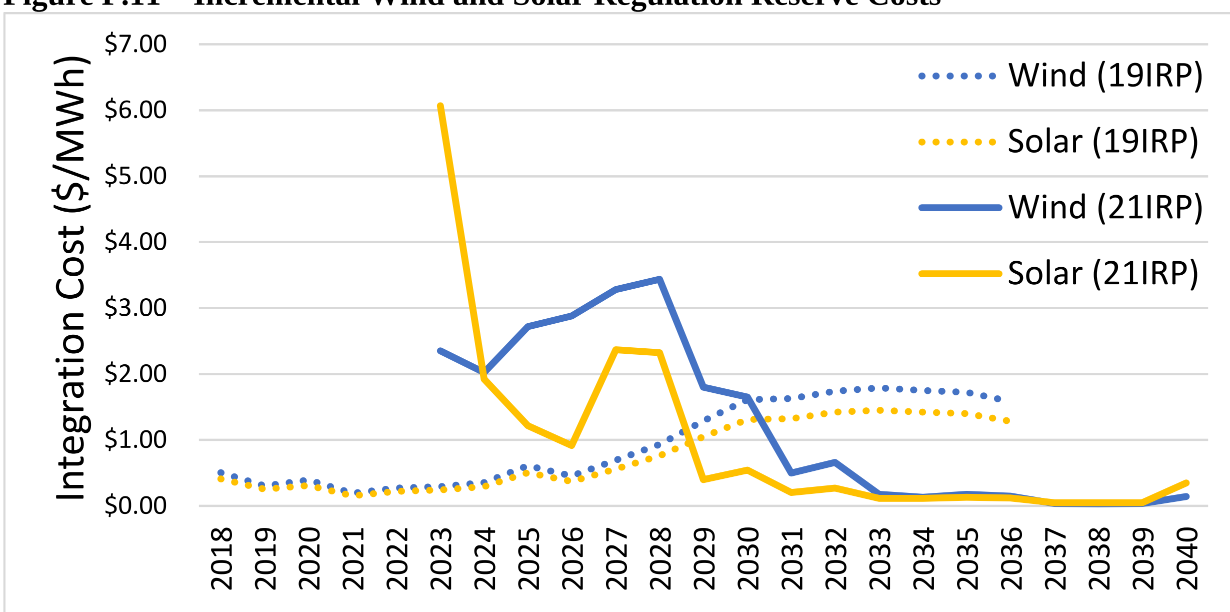
The wind reserve case uses the 2021 FRS methodology to recalculate the wind reserve requirement for a portfolio with 100 MW fewer wind resources in each year of the IRP study horizon (2021-2040). The reduction in resources is applied equally between PACE and PACW, and is allocated pro-rata among all wind resources in the area, such that the aggregate hourly capacity factor is not impacted by the change in capacity. Removing this wind capacity decreases regulation reserve requirements by an average of 14 MW. 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 100 MW fewer solar resources in each year of the IRP study horizon (2021-2040). 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. Removing this solar capacity decreases regulation reserve requirements by an average of 19 MW. 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 2019 FRS are also shown.

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



Solar generation is highest in the summer, when market prices and the cost of holding incremental reserves is relatively high. The impact of the reduced summer market purchase limit in the 2021 IRP is likely a contributing factor in the 2023 solar integration value. However, as solar resources become more prevalent, they tend to cause backdown of thermal generation in an increasing number of hours, and reductions in marginal prices, instead of impacting higher cost market transactions. As a result, many hours can have low or zero regulation reserve costs as solar penetration gets high. Hybrid solar and storage resources also drive down regulation reserve costs from the supply side, as storage resources are well suited for providing reserves. Due to their high flexibility and limited energy capacity storage resources can respond quickly if needed, but would otherwise be unlikely to dispatch until marginal costs are expected to be highest. This results in many hours with an excess of regulation reserve capability at no cost. As storage becomes increasingly prevalent in the Company's portfolio after 2030, integration costs drop to under $0.20/MWh for both wind and solar. In the 2019 IRP, solar combined with storage only included storage equivalent to 25% of the solar nameplate, so it had a much small impact on regulation reserve supply, and costs remained relatively high.

Flexible Resource Needs Assessment

Overview

In its Order No. 12013 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 2021 through 2040, 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 2021 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.10 below.

Table F.10 - Reserve Requirements (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)
2021	136	136	562	70	70	228
2022	140	140	572	71	71	213
2023	144	144	623	73	73	214
2024	146	146	624	74	74	200
2025	148	148	914	75	75	200
2026	145	145	905	76	76	329
2027	147	147	909	76	76	330
2028	148	148	912	77	77	327
2029	151	151	884	78	78	313
2030	153	153	931	79	79	298
2031	155	155	934	80	80	299
2032	157	157	936	81	81	393
2033	159	159	902	82	82	394
2034	161	161	890	82	82	392
2035	163	163	892	83	83	392
2036	164	164	870	84	84	393
2037	166	166	866	85	85	396
2038	168	168	869	85	85	396
2039	170	170	872	86	86	397
2040	171	171	882	86	86	387

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 contracted generation 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 thermal resources, the amount of reserve can be close to the differences between their nameplate capacities and their minimum generation levels. In the current IRP, PacifiCorp's reserve are served not only from existing coal- and gas-fired resources, but also from new gas-fired resources selected in the preferred portfolio.

Table F.11 lists the annual reserve capability from resources in PacifiCorp's East and West balancing authority areas.[20] All the resources included in the calculation are capable of providing all types of reserve. The non-spinning reserve resources under third party contracts are excluded in the calculations. 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.

[20] 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 2024 the battery capacity added in the preferred portfolio will exceed of PacifiCorp's current 202.8 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.11 - Flexible Resource Supply Forecast (MW)

Year	East Supply (10-Minute)	West Supply (10-Minute)	East Supply (30-Minute)	West Supply (30-Minute)
2021	705	268	1,455	525
2022	791	327	1,412	462
2023	863	375	1,521	429
2024	1,312	473	1,770	395
2025	1,625	515	2,325	368
2026	1,653	1,062	2,247	949
2027	1,662	1,086	2,232	939
2028	1,777	1,146	2,226	973
2029	2,316	1,167	2,398	921
2030	2,299	1,677	2,378	1,305
2031	3,006	1,705	3,055	1,319
2032	3,011	1,714	3,053	1,453
2033	3,667	1,720	3,830	1,480
2034	3,691	1,732	3,811	1,476
2035	3,714	1,760	3,784	1,465
2036	3,750	1,782	3,742	1,468
2037	4,610	2,465	4,418	2,039
2038	4,661	2,716	4,413	2,272
2039	4,510	2,715	4,246	2,256
2040	4,553	3,243	4,275	2,449

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.

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

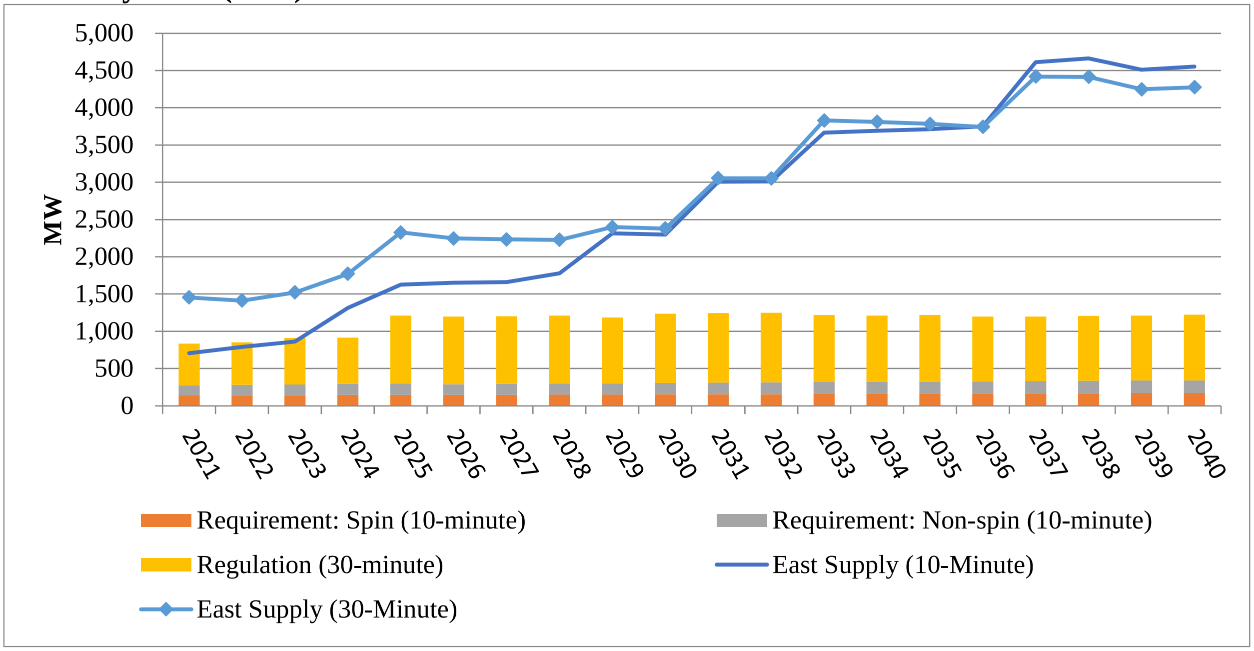
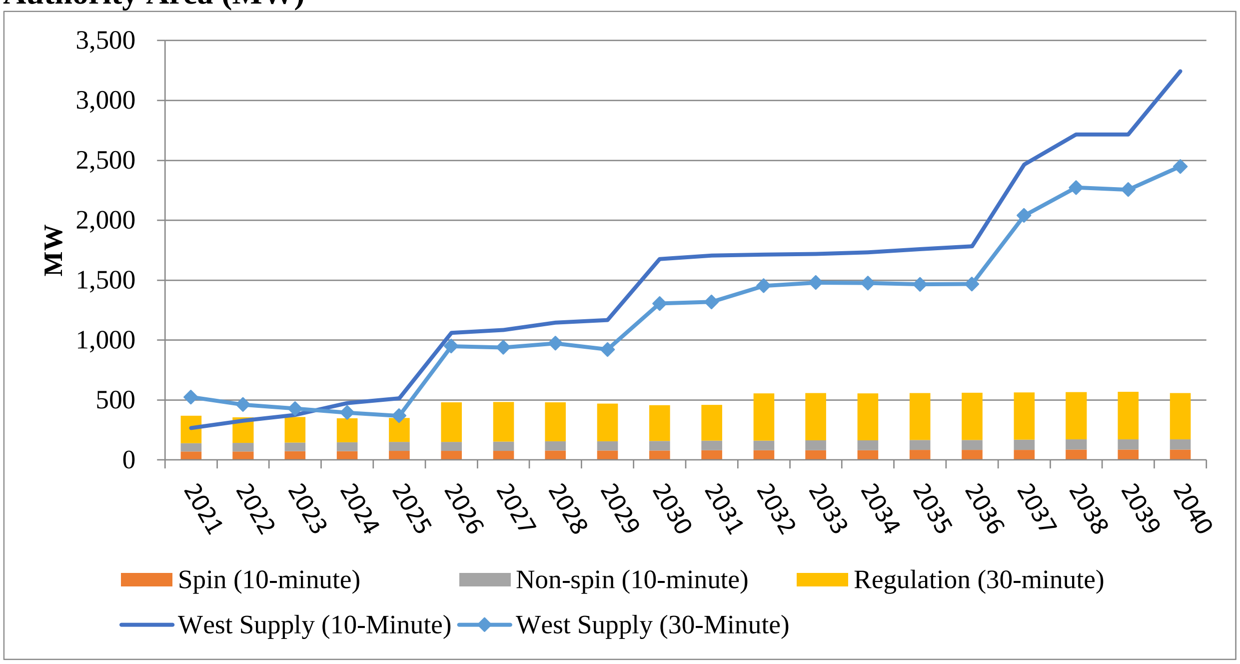


Figure F.13 - Comparison of Reserve Requirements and Resources, West Balancing Authority Area (MW)



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 2022. 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 the OPUC order, electric vehicle technologies may be able to meet flexible resource needs at some point in the future. However, the electric vehicle technology and market have not developed sufficiently to provide data for the current study. Since this analysis shows no gap between forecasted demand and supply of flexible resources over the IRP planning horizon, this IRP does not evaluate whether electric vehicles could be used to meet future flexible resource needs.

APPENDIX G – PLANT WATER CONSUMPTION STUDY

The information provide 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	2016	2017	2018	2019	4-year Average	2016	2017	2018	2019	2020	Gals/ MWH	GPM/ MW
Chehalis		Air	48	54	33	63	49	1,462,659	1,758,799	1,741,969	2,431,536	2,407,519	9	0.1
Currant Creek	Yes	Air	124	116	110	101	113	1,513,522	1,193,242	2,418,275	2,917,279	2,335,426	18	0.3
Dave Johnston		Water	8,864	8,231	8,325	8,485	8,476	5,088,505	4,519,908	4,800,371	4,686,381	4,325,604	579	9.6
Gadsby		Water	262	100	205	281	212	120,903	92,814	59,682	134,182	133,410	678	11.3
Hunter	Yes	Water	14,225	15,383	14,751	15,808	15,042	8,161,219	8,582,142	8,293,966	8,681,784	7,988,203	581	9.7
Huntington	Yes	Water	9,189	9,653	9,804	9,028	9,418	5,503,890	5,399,777	5,087,824	4,897,541	4,515,305	588	9.8
Jim Bridger	Yes	Water	18,000	19,047	20,067	19,893	19,252	11,688,747	11,642,810	10,966,745	11,254,989	10,458,575	551	9.2
Lake Side		Water	3,619	2,698	3,648	3,894	3,465	5,885,802	3,340,561	4,861,169	5,063,816	5,560,112	236	3.9
Naughton	Yes	Water	6,896	6,927	9,916	10,195	8,483	4,871,839	4,740,158	4,740,078	2,840,374	2,659,033	643	10.7
Wyodak	Yes	Air	329	332	319	292	318	2,054,311	2,565,053	2,254,203	1,852,094	1,732,784	48	0.8
TOTAL			**61,557**	**62,541**	**67,178**	**68,040**	**64,829**	**46,351,397**	**43,835,264**	**45,224,282**	**44,759,976**	**42,115,971**	**472**	**7.9**

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	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Currant Creek	84	92	78	124	116	110	101
Gadsby	610	367	1,022	262	100	205	281
Hunter	17,001	16,662	16,386	14,225	15,383	14,751	15,808
Huntington	10,643	10,240	9,888	9,189	9,653	9,804	9,028
Lake Side	1,361	2,960	4,533	3,619	2,698	3,648	3,894
TOTAL	**29,699**	**30,320**	**31,906**	**27,419**	**27,950**	**28,518**	**29,112**

Percent of total water consumption = 42.9%

WYOMING PLANTS							
Plant Name	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Dave Johnston	8,941	9,474	9,736	8,864	8,231	8,325	8,485
Jim Bridger	25,059	23,936	22,493	18,000	19,047	20,067	19,893
Naughton	9,622	7,484	9,160	6,896	6,927	9,916	10,195
Wyodak	319	332	228	329	332	319	292
TOTAL	**43,941**	**41,225**	**41,617**	**34,090**	**34,537**	**38,627**	**38,865**

Percent of total water consumption = 57.1%

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

COAL FIRED PLANTS							
Plant Name	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Dave Johnston	8,941	9,474	9,736	8,864	7,721	8,941	9,474
Hunter	17,001	16,662	16,386	14,225	18,266	17,001	16,662
Huntington	10,643	10,240	9,888	9,189	10,423	10,643	10,240
Jim Bridger	25,059	23,936	22,493	18,000	23,977	25,059	23,936
Naughton	9,622	7,484	9,160	6,896	8,745	9,622	7,484
Wyodak	319	332	228	329	322	319	332
TOTAL	**71,585**	**68,127**	**67,891**	**57,504**	**69,454**	**71,585**	**68,127**

Percent of total water consumption = 94.7%

NATURAL GAS FIRED PLANTS							
Plant Name	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Currant Creek	84	92	78	124	116	110	101
Chehalis	86	150	93	48	54	33	63
Gadsby	610	367	1,022	262	100	205	281
Lake Side	1,361	2,960	4,533	3,619	2,698	3,648	3,894
TOTAL	**2,141**	**3,568**	**5,725**	**4,053**	**2,968**	**3,996**	**4,339**

Percent of total water consumption = 5.3%

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

Plant Name	2013	2014	2015	2016	2017	2018	2019
Hunter	17,001	16,662	16,386	14,225	15,383	14,751	15,808
Huntington	10,643	10,240	9,888	9,189	9,653	9,804	9,028
Naughton	9,622	7,484	9,160	6,896	6,927	9,916	10,195
Jim Bridger	25,059	23,936	22,493	18,000	19,047	20,067	19,893
TOTAL	**62,325**	**58,322**	**57,927**	**48,311**	**51,010**	**54,537**	**54,924**

Percent of total water consumption = 81.1%

APPENDIX H – STOCHASTIC PARAMETERS

Introduction

For the 2021 IRP, PacifiCorp updated and re-estimated the stochastic parameters provided in the 2019 IRP for use in the development of the 2021 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:

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

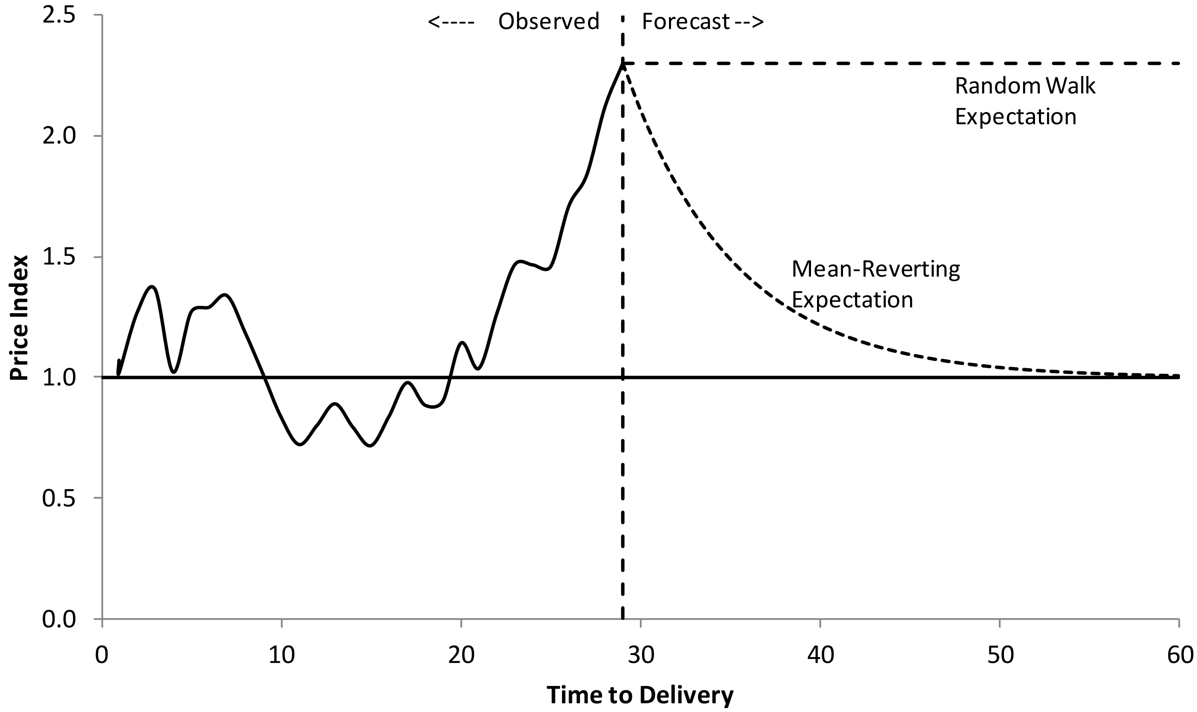
Volatilities are typically quoted on an annual basis but can be specified for any desired time period (T). Suppose the annual volatility of load is two percent. This implies that the standard deviation of the range of possible loads a year from now is two percent, while the standard deviation four years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

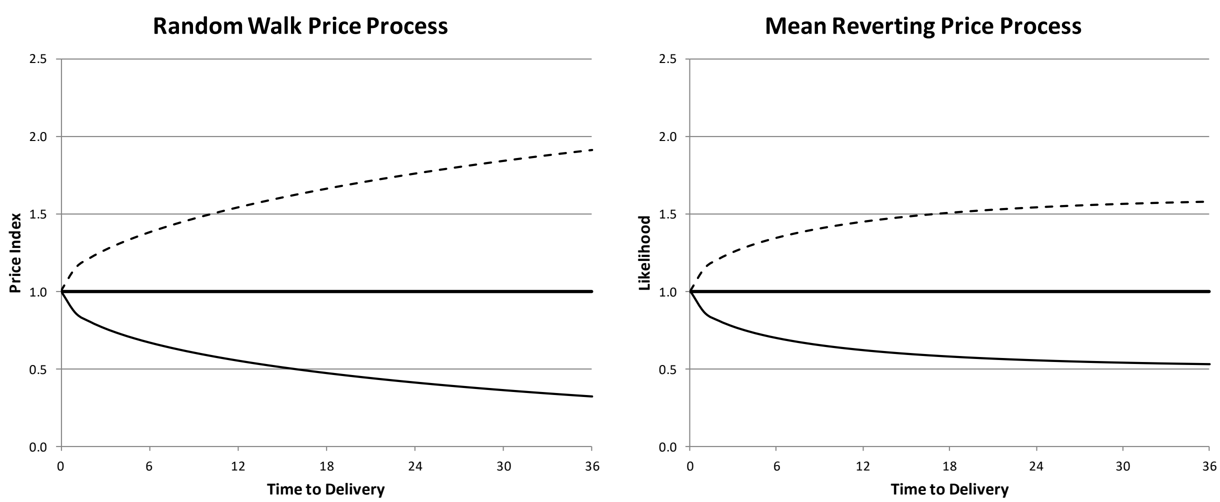
[3] "Standard Deviation" and "Variance" are standard statistical terms describing the spread of possible outcomes. The Variance equals the Standard Deviation squared.

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.

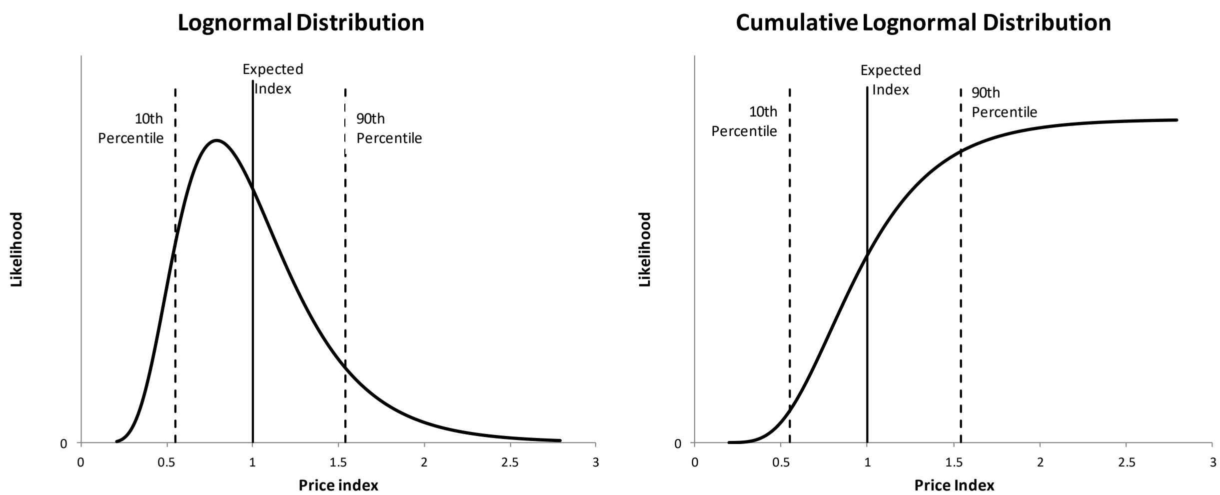
Estimating Short-term Process Parameters

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:

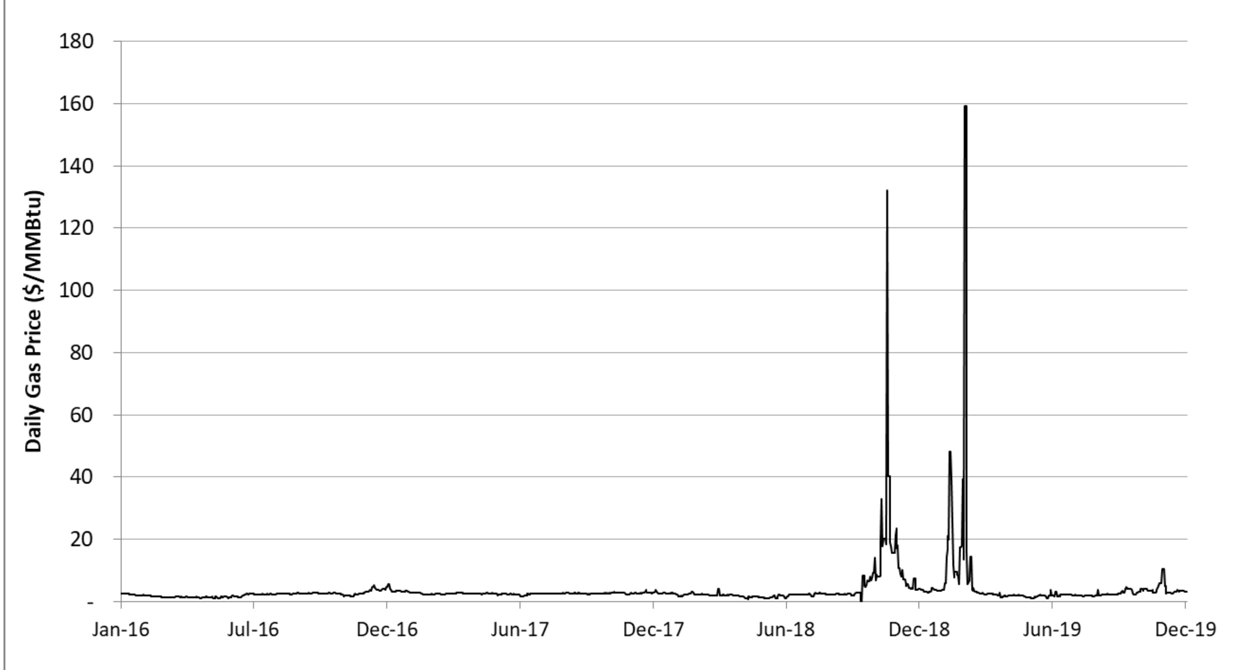
Table H.1 - Seasonal Definitions

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 2016 to 2019 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, 2016-2019



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. In order 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:

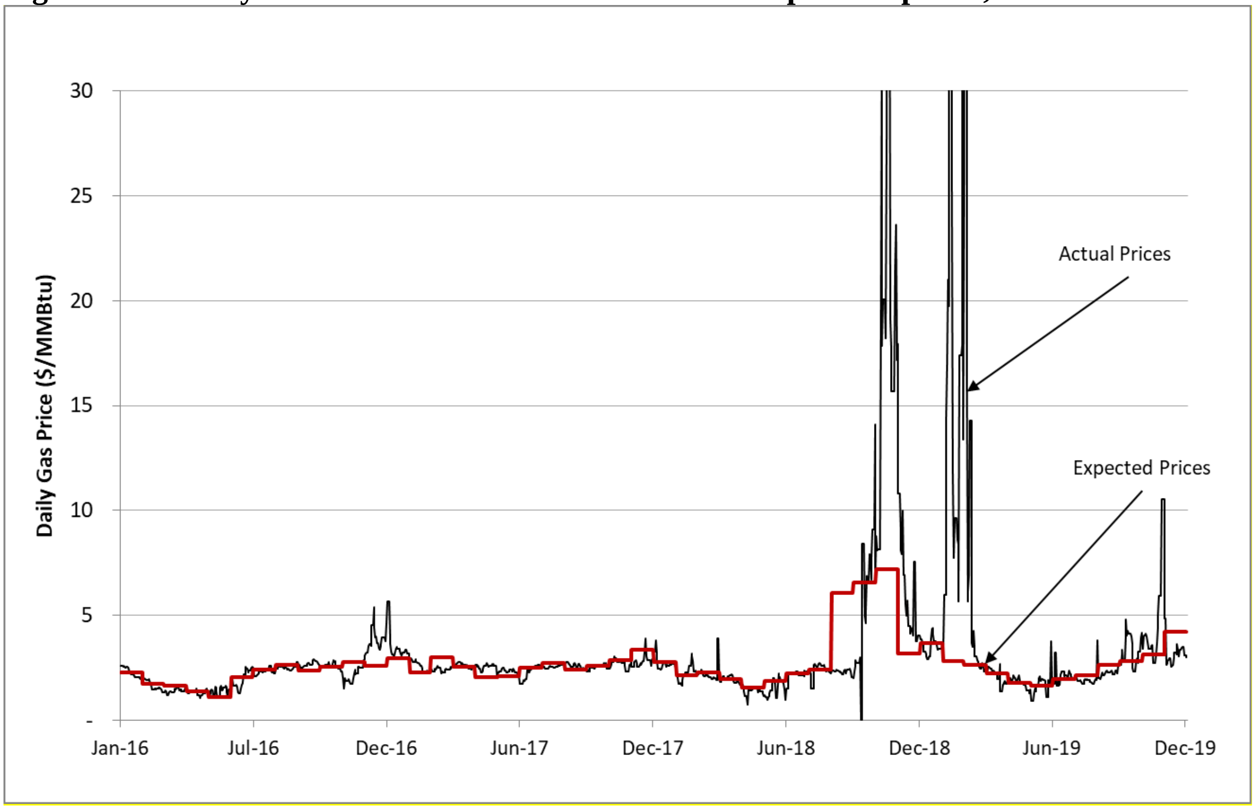
> Seasonal Median: The level of gas prices may be different from one year to the next. While this can be attributed to random movements or shocks in the gas markets, it is not a short-term event and should not be included in the short-term uncertainty process. In order to account for this possible difference 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 2016 average \$2.21/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 79 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 two 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, 2016 was \$1.75/MMBtu, the product of the seasonal median and the monthly shape factor

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

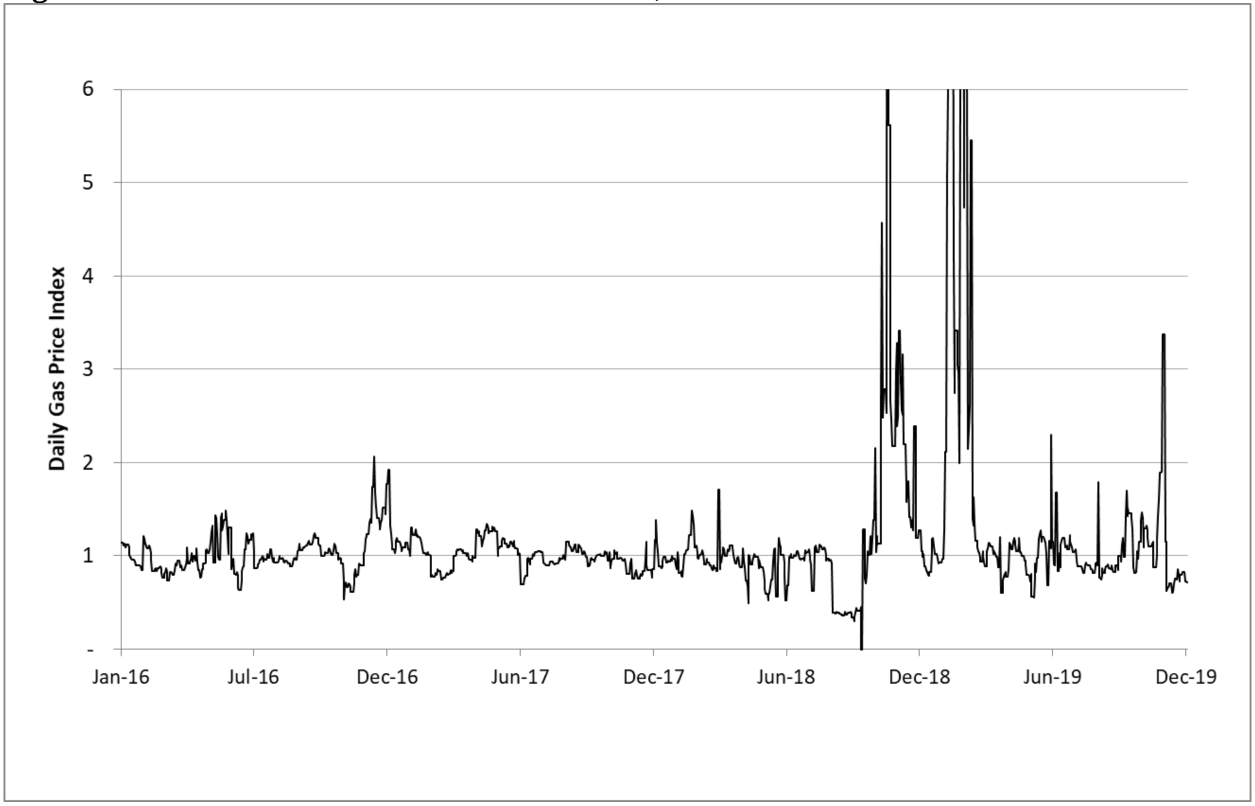
The following chart shows the comparison of the actual Sumas prices with the "expected" prices:

Figure H.5 – Daily Gas Prices for SUMAS Basin with "expected" prices, 2016-2019



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, 2016-2019



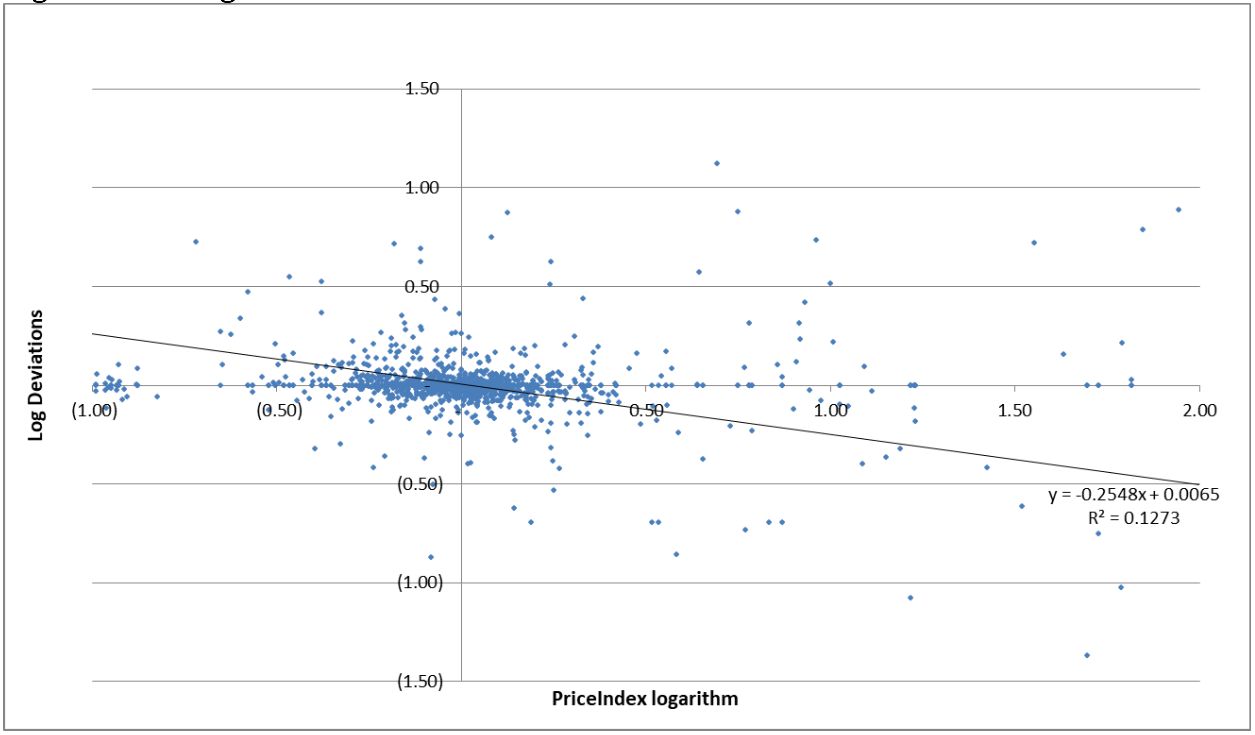
Parameter Estimation – Autoregressive Model

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	11.48%	9.05%	9.91%	10.07%
Daily Mean Reversion Rate	0.061	0.160	0.503	0.046
SUMAS				
Daily Volatility	16.65%	20.30%	13.06%	17.14%
Daily Mean Reversion Rate	0.031	0.140	0.287	0.022

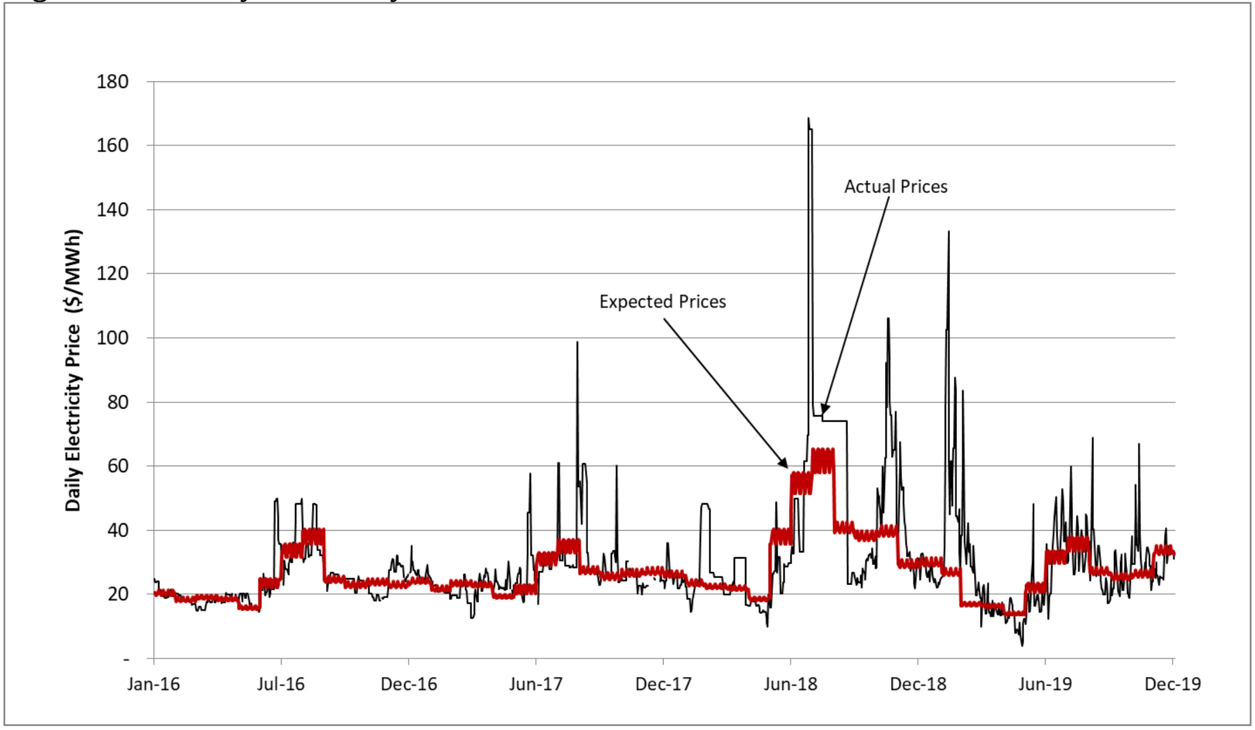
Electricity Price Process

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. Similar to 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, similar to gas prices. The data covers the 2016 through 2019 time 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). In order 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 similar to 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, 2016 in the Four Corners region was $20.45/megawatt hours (MWh). This price incorporates the 2016 winter median price of $20.33/MWh times the monthly shape factor for January of 99 percent and the weekday index for Saturday of 101 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, 2016-2019



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.

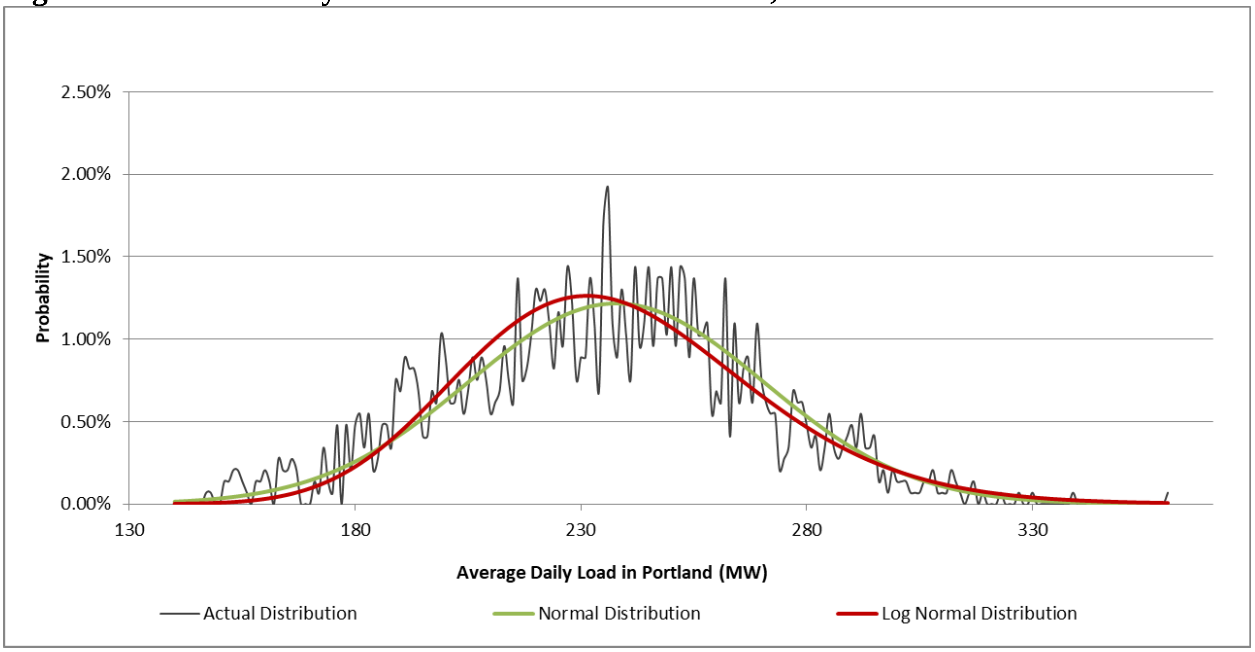
Table H.3 - Uncertainty Parameters for Electricity Regions

	Winter	Spring	Summer	Fall
Four Corners				
Daily Volatility	13.22%	17.19%	21.99%	17.41%
Daily Mean Reversion Rate	0.089	0.180	0.312	0.197
CA-OR Border				
Daily Volatility	16.31%	28.78%	33.94%	17.32%
Daily Mean Reversion Rate	0.070	0.258	0.395	0.178
Mid-Columbia				
Daily Volatility	19.81%	63.03%	25.97%	16.00%
Daily Mean Reversion Rate	0.090	0.461	0.196	0.120
Palo Verde				
Daily Volatility	12.11%	13.81%	20.17%	15.02%
Daily Mean Reversion Rate	0.086	0.151	0.146	0.163

Regional Load Process

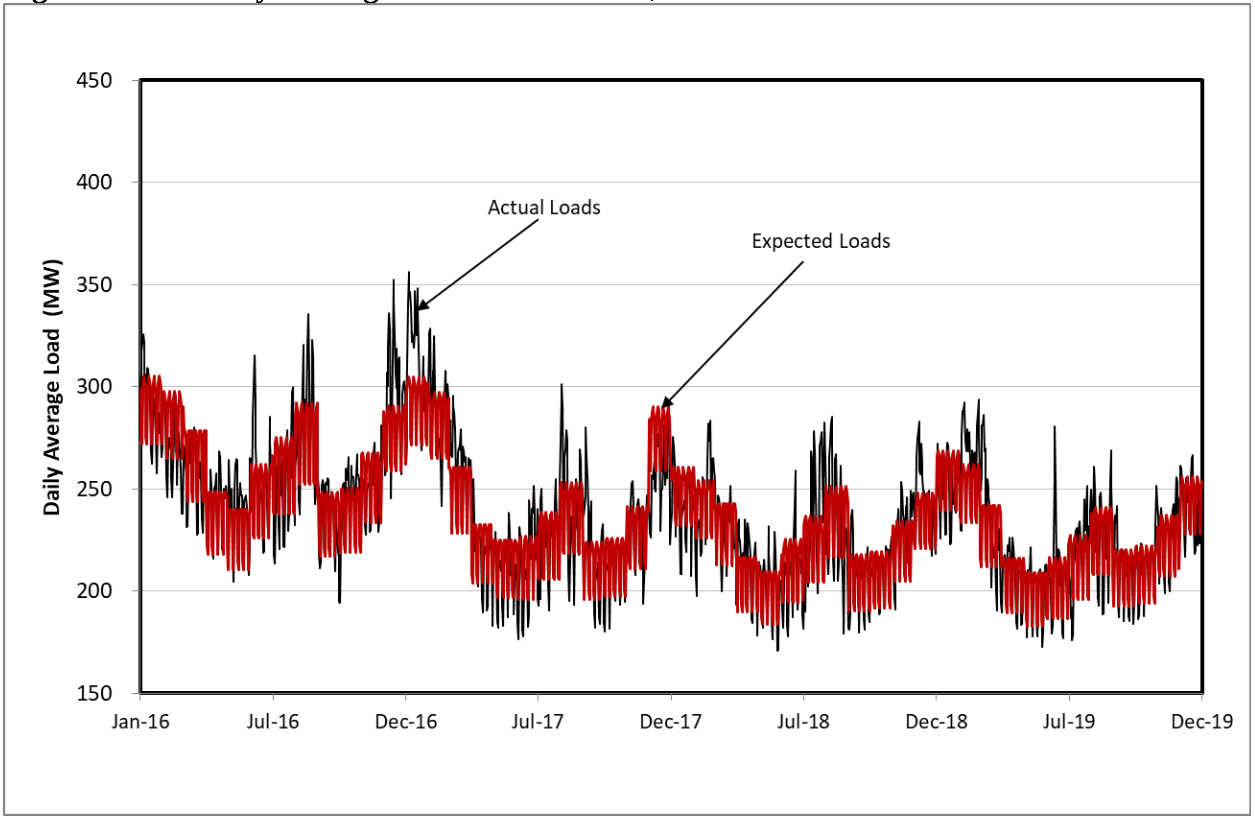
There are only two significant differences between the uncertainty analysis for regional loads and natural gas prices. The distribution of daily loads is somewhat better represented by a normal distribution rather than a lognormal distribution, and, similar to electricity prices, loads have a significant 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, 2016-2019



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, 2016 in Portland was 276 megawatts (MW). This load incorporates the 2016 winter average load of 286 MW times the monthly shape factor for January of 102 percent and the weekday index for Saturday also of 94 percent. The following chart shows the Portland actual and expected loads over the analysis time period.

Figure H.10 – Daily Average Load for Portland, 2016-2019



Load Uncertainty Parameters:
Uncertainty parameters are calculated for each load region, similar to 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

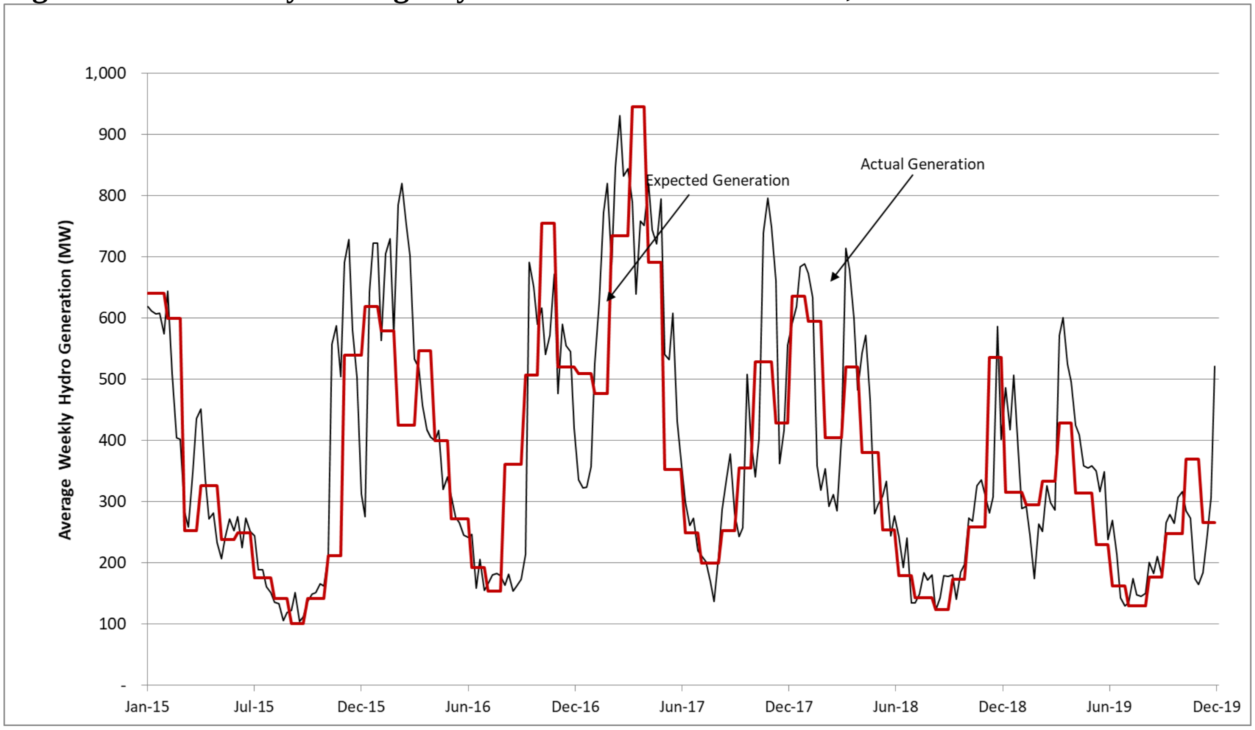
	Winter	Spring	Summer	Fall
California				
Daily Volatility	4.8%	4.4%	3.8%	4.5%
Daily Mean Reversion Rate	0.208	0.193	0.223	0.238
Idaho				
Daily Volatility	3.6%	6.4%	5.3%	4.2%
Daily Mean Reversion Rate	0.179	0.271	0.135	0.184
Portland				
Daily Volatility	3.8%	3.5%	5.5%	3.6%
Daily Mean Reversion Rate	0.157	0.225	0.258	0.285
Oregon Other				
Daily Volatility	4.4%	3.6%	4.1%	4.0%
Daily Mean Reversion Rate	0.152	0.249	0.190	0.294
Utah				
Daily Volatility	2.3%	3.0%	4.7%	3.2%
Daily Mean Reversion Rate	0.278	0.535	0.296	0.203
Washington				
Daily Volatility	5.0%	3.9%	5.0%	4.1%
Daily Mean Reversion Rate	0.149	0.179	0.191	0.226
Wyoming				
Daily Volatility	1.6%	1.8%	1.7%	1.7%
Daily Mean Reversion Rate	0.226	0.270	0.224	0.232

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 2015 through 2019 time 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, 2015 through January 7, 2015 in the Western Region was 641 MW. This generation incorporates the 2015 winter median generation of 594 MW times the monthly shape factor for January of 108 percent. The following chart shows the western hydro actual and expected generation over the analysis time period.

Figure H.11 – Weekly Average Hydro Generation in the West, 2015-2019



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	27.40%	18.91%	20.97%	29.81%
Weekly Mean Reversion Rate	0.72	0.43	1.15	0.37

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 of the variables. The residual error represents the random portion of the deviation not explained by mean reversion. It is calculated for each time 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:

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

There are a few things to note about the correlation calculations. First, correlation data must always be organized so that the same time 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

SHORT-TERM WINTER CORRELATIONS

	K-O	SUMAS	4C	COB	Mid-C	PV	CA	ID	Portland	OR Other	UT	WA	WY	Hydro
K-O	100%	34%	41%	38%	32%	49%	10%	2%	17%	16%	17%	20%	3%	-1%
SUMAS	34%	100%	24%	30%	29%	25%	13%	13%	12%	12%	15%	19%	9%	-2%
4C	41%	24%	100%	62%	54%	79%	16%	-8%	17%	20%	23%	25%	5%	-3%
COB	38%	30%	62%	100%	76%	59%	17%	-5%	21%	25%	23%	33%	8%	4%
Mid-C	32%	29%	54%	76%	100%	56%	15%	0%	26%	32%	21%	36%	9%	6%
PV	49%	25%	79%	59%	56%	100%	13%	-8%	11%	15%	16%	19%	6%	-4%
CA	10%	13%	16%	17%	15%	13%	100%	12%	32%	70%	30%	35%	19%	2%
ID	2%	13%	-8%	-5%	0%	-8%	12%	100%	19%	20%	34%	29%	24%	-5%
Portland	17%	12%	17%	21%	26%	11%	32%	19%	100%	69%	43%	65%	23%	-6%
OR Other	16%	12%	20%	25%	32%	15%	70%	20%	69%	100%	44%	64%	20%	8%
UT	17%	15%	23%	23%	21%	16%	30%	34%	43%	44%	100%	45%	40%	-5%
WA	20%	19%	25%	33%	36%	19%	35%	29%	65%	64%	45%	100%	28%	13%
WY	3%	9%	5%	8%	9%	6%	19%	24%	23%	20%	40%	28%	100%	-3%
Hydro	-1%	-2%	-3%	4%	6%	-4%	2%	-5%	-6%	8%	-5%	13%	-3%	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 negative five 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

SHORT-TERM SPRING CORRELATIONS

	K-O	SUMAS	4C	COB	Mid-C	PV	CA	ID	Portland	OR Other	UT	WA	WY	Hydro
K-O	100%	56%	20%	14%	10%	22%	7%	7%	13%	14%	12%	13%	9%	1%
SUMAS	56%	100%	19%	21%	17%	10%	1%	6%	12%	13%	10%	17%	8%	-6%
4C	20%	19%	100%	34%	42%	63%	8%	11%	27%	21%	22%	23%	18%	1%
COB	14%	21%	34%	100%	64%	33%	14%	1%	28%	24%	13%	31%	14%	9%
Mid-C	10%	17%	42%	64%	100%	28%	12%	3%	21%	15%	8%	27%	11%	8%
PV	22%	10%	63%	33%	28%	100%	10%	13%	21%	17%	24%	23%	16%	-1%
CA	7%	1%	8%	14%	12%	10%	100%	16%	35%	68%	24%	40%	12%	-7%
ID	7%	6%	11%	1%	3%	13%	16%	100%	6%	17%	46%	20%	20%	-18%
Portland	13%	12%	27%	28%	21%	21%	35%	6%	100%	69%	19%	60%	25%	1%
OR Other	14%	13%	21%	24%	15%	17%	68%	17%	69%	100%	30%	67%	23%	-3%
UT	12%	10%	22%	13%	8%	24%	24%	46%	19%	30%	100%	21%	32%	-22%
WA	13%	17%	23%	31%	27%	23%	40%	20%	60%	67%	21%	100%	22%	0%
WY	9%	8%	18%	14%	11%	16%	12%	20%	25%	23%	32%	22%	100%	-17%
Hydro	1%	-6%	1%	9%	8%	-1%	-7%	-18%	1%	-3%	-22%	0%	-17%	100%

Similarly, the spring season shows a very low correlation of 12 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

SHORT-TERM SUMMER CORRELATIONS

	K-O	SUMAS	4C	COB	Mid-C	PV	CA	ID	Portland	OR Other	UT	WA	WY	Hydro
K-O	100%	67%	7%	16%	12%	6%	-2%	1%	5%	4%	0%	9%	0%	0%
SUMAS	67%	100%	4%	10%	8%	0%	-12%	-4%	2%	-3%	-3%	2%	-1%	3%
4C	7%	4%	100%	22%	23%	44%	25%	13%	23%	28%	29%	23%	17%	-8%
COB	16%	10%	22%	100%	80%	45%	14%	7%	37%	31%	10%	27%	6%	5%
Mid-C	12%	8%	23%	80%	100%	54%	21%	8%	48%	41%	12%	30%	2%	1%
PV	6%	0%	44%	45%	54%	100%	27%	16%	34%	33%	27%	26%	16%	0%
CA	-2%	-12%	25%	14%	21%	27%	100%	44%	37%	66%	35%	52%	18%	-9%
ID	1%	-4%	13%	7%	8%	16%	44%	100%	13%	27%	51%	22%	24%	-10%
Portland	5%	2%	23%	37%	48%	34%	37%	13%	100%	79%	10%	62%	-1%	8%
OR Other	4%	-3%	28%	31%	41%	33%	66%	27%	79%	100%	21%	80%	8%	2%
UT	0%	-3%	29%	10%	12%	27%	35%	51%	10%	21%	100%	22%	48%	-15%
WA	9%	2%	23%	27%	30%	26%	52%	22%	62%	80%	22%	100%	5%	-1%
WY	0%	-1%	17%	6%	2%	16%	18%	24%	-1%	8%	48%	5%	100%	-12%
Hydro	0%	3%	-8%	5%	1%	0%	-9%	-10%	8%	2%	-15%	-1%	-12%	100%

In the summer season, six 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

SHORT-TERM FALL CORRELATIONS

	K-O	SUMAS	4C	COB	Mid-C	PV	CA	ID	Portland	OR Other	UT	WA	WY	Hydro
K-O	100%	36%	21%	25%	23%	17%	19%	3%	7%	18%	7%	11%	6%	-11%
SUMAS	36%	100%	13%	20%	23%	16%	16%	-4%	10%	17%	5%	6%	6%	-13%
4C	21%	13%	100%	29%	28%	61%	14%	5%	16%	12%	23%	13%	7%	-6%
COB	25%	20%	29%	100%	60%	40%	21%	3%	26%	24%	19%	23%	13%	-13%
Mid-C	23%	23%	28%	60%	100%	43%	22%	6%	29%	30%	18%	29%	9%	-7%
PV	17%	16%	61%	40%	43%	100%	10%	5%	17%	8%	18%	10%	10%	0%
CA	19%	16%	14%	21%	22%	10%	100%	26%	56%	80%	38%	64%	31%	-4%
ID	3%	-4%	5%	3%	6%	5%	26%	100%	18%	20%	39%	21%	28%	-12%
Portland	7%	10%	16%	26%	29%	17%	56%	18%	100%	80%	46%	71%	35%	4%
OR Other	18%	17%	12%	24%	30%	8%	80%	20%	80%	100%	46%	81%	40%	1%
UT	7%	5%	23%	19%	18%	18%	38%	39%	46%	46%	100%	43%	41%	-2%
WA	11%	6%	13%	23%	29%	10%	64%	21%	71%	81%	43%	100%	36%	4%
WY	6%	6%	7%	13%	9%	10%	31%	28%	35%	40%	41%	36%	100%	-2%
Hydro	-11%	-13%	-6%	-13%	-7%	0%	-4%	-12%	4%	1%	-2%	4%	-2%	100%

In the fall, a low correlation of nine 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.

APPENDIX I – CAPACITY EXPANSION RESULTS

Portfolio-Development Cases Quick Reference Guide

This appendix provides a reference guide to portfolio capacity expansion results for each portfolio in the 2021 IRP. Capacity expansion result information is further described in Volume I, Chapter 8 – Modeling and Portfolio Evaluation Approach and Volume I, Chapter 9 – Modeling and Portfolio Selection Results.

Table I.1 –Preferred Portfolio

Case	Description	Risk-Adjusted PVRR ($m)	Price-Policy	Load	Private Gen
P02-MM-CETA	P02-MM (top-performing portfolio) with WA-situs resources relative to CETA requirements.	$26,343	Med Gas, Med CO_2	Base	Base

Table I.2 – Initial Portfolios

Case	Description	Risk-Adjusted PVRR ($m)	Price-Policy	Load	Private Gen
P02-LN	Existing coal and new proxy resources optimized	$22,252	Low Gas, No CO_2	Base	Base
P02-MN	Existing coal and new proxy resources optimized	$22,256	Med Gas, No CO_2	Base	Base
P02-MM	Existing coal and new proxy resources optimized	$26,179	Med Gas, Med CO_2	Base	Base
P02-HH	Existing coal and new proxy resources optimized	$27,993	High Gas, High CO_2	Base	Base
P02-SCGHG	Existing coal and new proxy resources optimized	$39,318	Med Gas, Social Cost of Greenhouse Gas	Base	Base
P03-LN	Existing coal retired by 2030, new proxy resources optimized	$24,772	Low Gas, No CO_2	Base	Base
P03-MN	Existing coal retired by 2030, new proxy resources optimized	$25,780	Med Gas, No CO_2	Base	Base
P03-MM	Existing coal retired by 2030, new proxy resources optimized	$27,876	Med Gas, Med CO_2	Base	Base
P03-HH	Existing coal retired by 2030, new proxy resources optimized	$29,030	High Gas, High CO_2	Base	Base
P03-SCGHG	Existing coal retired by 2030, new proxy resources optimized	$39,140	Med Gas, Social Cost of Greenhouse Gas	Base	Base
BAU1-LN	Business-as-usual scenario - existing coal retires end-of-life, new proxy resources optimized	$22,663	Low Gas, No CO_2	Base	Base
BAU1-MN	Business-as-usual scenario - existing coal retires end-of-life, new proxy resources optimized	$22,677	Med Gas, No CO_2	Base	Base
BAU1-MM	Business-as-usual scenario - existing coal retires end-of-life, new proxy resources optimized	$27,200	Med Gas, Med CO_2	Base	Base
BAU1-HH	Business-as-usual scenario - existing coal retires end-of-life, new proxy resources optimized	$29,804	High Gas, High CO_2	Base	Base
BAU1-SCGHG	Business-as-usual scenario - existing coal retires end-of-life, new proxy resources optimized	$41,421	Med Gas, Social Cost of Greenhouse Gas	Base	Base
BAU2-LN	Business-as-usual scenario - existing coal 2019 IRP retirements, new proxy resources optimized	$22,735	Low Gas, No CO_2	Base	Base
BAU2-MN	Business-as-usual scenario - existing coal 2019 IRP retirements, new proxy resources optimized	$22,702	Med Gas, No CO_2	Base	Base
BAU2-MM	Business-as-usual scenario - existing coal 2019 IRP retirements, new proxy resources optimized	$27,054	Med Gas, Med CO_2	Base	Base
BAU2-HH	Business-as-usual scenario - existing coal 2019 IRP retirements, new proxy resources optimized	$29,384	High Gas, High CO_2	Base	Base

BAU2-SCGHG	Business-as-usual scenario - existing coal 2019 IRP retirements, new proxy resources optimized	$41,224	Med Gas, Social Cost of Greenhouse Gas	Base	Base

Table I.3 – P02 Variant Portfolios

Case	Description	Risk-Adjusted PVRR ($m)	Price-Policy	Load	Private Gen
P02a-JB 1-2 No GC	Variant of P02-MM (top-performing portfolio) excludes gas conversion of Jim Bridger Units 1 and 2	$26,648	Med Gas, Med CO_2	Base	Base
P02b-No B2H	Variant of P02-MM (top-performing portfolio) excludes Boardman-to-Hemingway transmission segment	$26,633	Med Gas, Med CO_2	Base	Base
P02c-No GWS	Variant of P02-MM (top-performing portfolio) excludes the Energy Gateway South transmission segment	$26,439	Med Gas, Med CO_2	Base	Base
P02d-No RFP	Variant of P02-MM (top-performing portfolio) excludes the 2020 All-Source Request for Proposals Final Shortlist and the Energy Gateway South transmission segment	$27,445	Med Gas, Med CO_2	Base	Base
P02e-No Nuc	Variant of P02-MM (top-performing portfolio) excludes the Natrium^{TM} advanced nuclear demonstration project	$26,337	Med Gas, Med CO_2	Base	Base
P02f-No Nau 25	Variant of P02-MM (top-performing portfolio) excludes the early retirement of Naughton Units 1 and 2	$26,245	Med Gas, Med CO_2	Base	Base
P02g-CCUS	Variant of P02-MM (top-performing portfolio) includes Carbon Capture Utilization and Sequestration (CCUS) retrofit of Dave Johnston Unit 4	$26,415	Med Gas, Med CO_2	Base	Base
P02h-JB 3-4 Retire	Variant of P02-MM (top-performing portfolio) includes early retirement of Jim Bridger Units 3 and 4 in response to stakeholder feedback	$26,240	Med Gas, Med CO_2	Base	Base

Table I.4 – Washington Clean Energy Transmission Act (CETA) Required Scenarios

Case	Description	Risk-Adjusted PVRR ($m)	Price-Policy	Load	Private Gen
Alternative Lowest Reasonable Cost	Describes the alternative lowest reasonable cost and reasonably available portfolio that that would have been implemented if not for the requirement to comply with CETA.	$26,525	Med Gas, Med CO_2	Base	Base
Climate Change	A scenario that assesses the impacts of climate change.	$40,904	Med Gas, Med CO_2	Base	Base
Maximum Customer Benefit	A scenario that maximizes customer benefits prior to balancing against other goals.	$43,310	Med Gas, Med CO_2	Base	Base

Portfolio: Initial Portfolio P02-MM-CETA

Preferred Portfolio Fact Sheet

PORTFOLIO ASSUMPTIONS

Description

The preferred portfolio P02-MM-CETA, is based on P02-MM, the top-performing portfolio and includes Washington-situs resources relative to requirements of Washington's Clean Energy Transformation Act (CETA).

PORTFOLIO SUMMARY

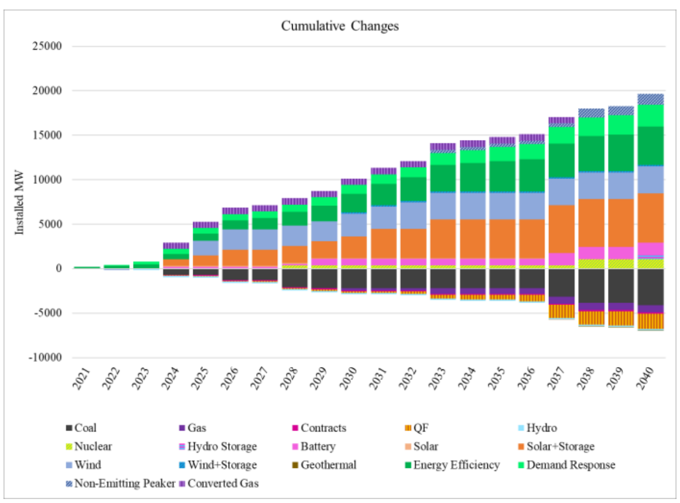
Risk-Adjusted PVRR ($m) ***$26,343***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as cumulative nameplate capacity, are summarized in the figure below.



Retirement Assumptions

Thermal retirement assumptions for P02-MM-CETA are summarized in the following table.

Unit	Description
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	GC 2023, Retire 2037
Jim Bridger 2	GC 2023, Retire 2037
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3 GC	Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

P02 is a set of initial portfolios where existing coal and new proxy resources are optimized. P02 initial portfolios were developed under each of the five price-policy scenarios. This portfolio fact sheet presents high-level information for P02-LN, the portfolio developed under a low gas / no CO_2 price-policy assumption.

PORTFOLIO SUMMARY

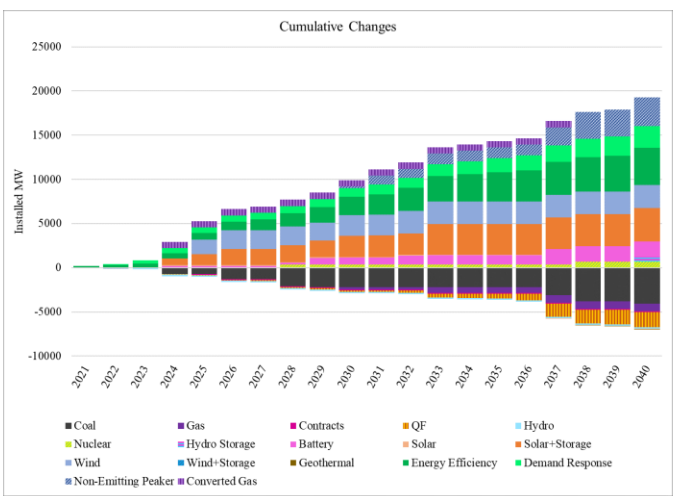
Risk-Adjusted PVRR ($m) ***$22,252***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as cumulative nameplate capacity, are summarized in the figure below.



Retirement Assumptions

Thermal retirement assumptions for P02-LN are summarized in the following table.

Unit	Description
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	GC 2023, Retire 2037
Jim Bridger 2	GC 2023, Retire 2037
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3 GC	Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

P02 is a set of initial portfolios where existing coal and new proxy resources are optimized. P02 initial portfolios were developed under each of the five price-policy scenarios. This portfolio fact sheet presents high-level information for P02-MN, the portfolio developed under a medium gas / no CO_2 price-policy assumption.

PORTFOLIO SUMMARY

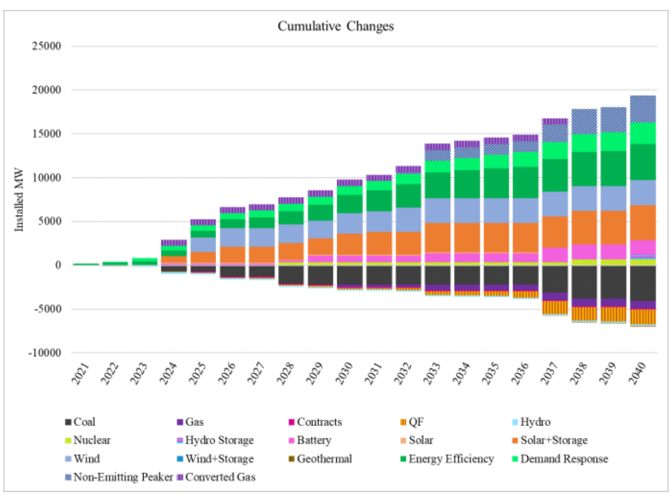
Risk-Adjusted PVRR ($m) $22,256

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

Thermal retirement assumptions for P02-MN are summarized in the following table.

Unit	Description
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	GC 2023, Retire 2037
Jim Bridger 2	GC 2023, Retire 2037
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3 GC	Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

P02 is a set of initial portfolios where existing coal and new proxy resources are optimized. P02 initial portfolios were developed under each of the five price-policy scenarios. This portfolio fact sheet presents high-level information for P02-MM, the portfolio developed under a medium gas / medium CO_2 price-policy assumption.

PORTFOLIO SUMMARY

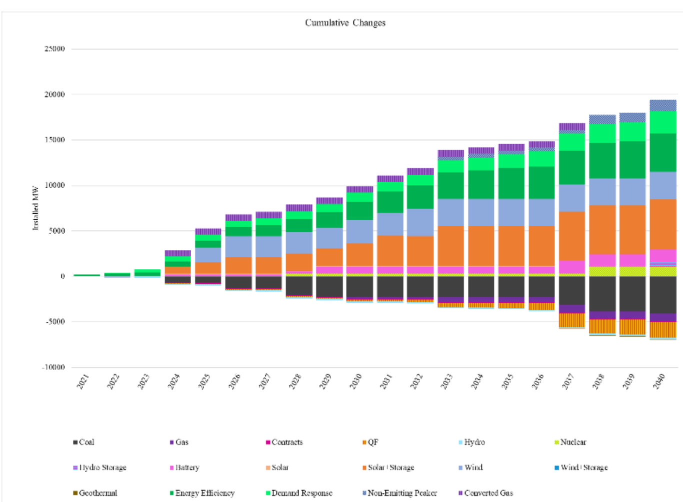
Risk-Adjusted PVRR ($m) $26,179

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

Thermal retirement assumptions for P02-MM are summarized in the following table.

Unit	Description
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	GC 2023, Retire 2037
Jim Bridger 2	GC 2023, Retire 2037
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3 GC	Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description
P02 is a set of initial portfolios where existing coal and new proxy resources are optimized. P02 initial portfolios were developed under each of the five price-policy scenarios. This portfolio fact sheet presents high-level information for P02-HH, the portfolio developed under a high gas / high CO_2 price-policy assumption.

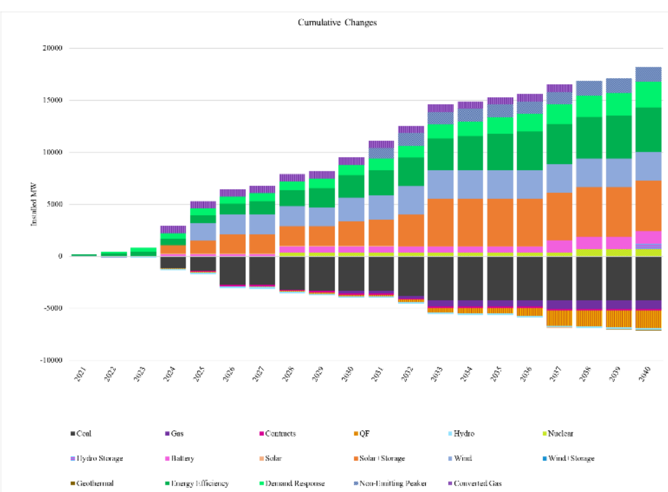
PORTFOLIO SUMMARY

Risk-Adjusted PVRR ($m) $27,993

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

Resource Portfolio
Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions
Thermal retirement assumptions for P02-HH are summarized in the following table.

Unit	Description
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	CCUS 2026
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2023
Hunter 2	Retire 2024
Hunter 3	Retire 2025
Huntington 1	Retire 2031
Huntington 2	Retire 2032
Jim Bridger 1	GC 2023, Retire 2037
Jim Bridger 2	GC 2023, Retire 2037
Jim Bridger 3	CCUS 2026
Jim Bridger 4	CCUS 2026
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3 GC	Retire 2029
Wyodak	CCUS 2026

CCUS = carbon capture and sequestration
GC = gas conversion

Portfolio: Initial Portfolios (P02-SCGHG)

Initial Portfolio-Development Fact Sheets

Portfolio Assumptions

Description

P02 is a set of initial portfolios where existing coal and new proxy resources are optimized. P02 initial portfolios were developed under each of the five price-policy scenarios. This portfolio fact sheet presents high-level information for P02-SCGHG, the portfolio developed under a medium gas / social cost of greenhouse gas price-policy assumption.

Portfolio Summary

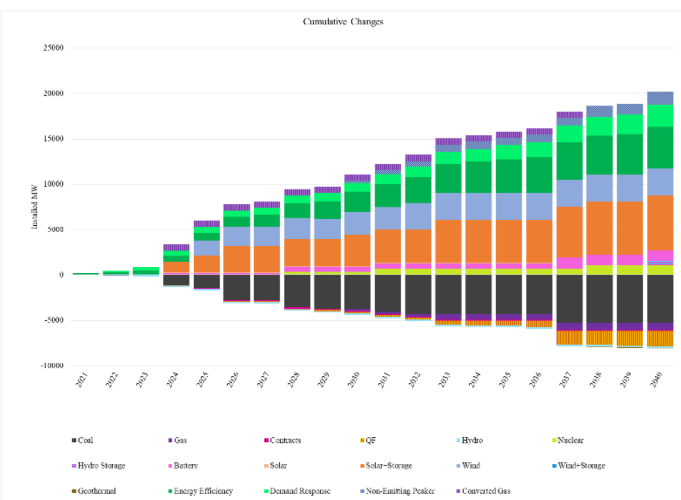
Risk-Adjusted PVRR ($m) ***$39,318***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

Thermal retirement assumptions for P02-SCGHG are summarized in the following table.

Unit	Description
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2023
Hunter 2	Retire 2024
Hunter 3	Retire 2025
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	GC 2023, Retire 2037
Jim Bridger 2	GC 2023, Retire 2037
Jim Bridger 3	Retire 2025
Jim Bridger 4	Retire 2030
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3 GC	Retire 2029
Wyodak	Retire 2031

GC = gas conversion

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

P03 is a set of initial portfolios where all existing coal units are assumed to retire by 2030. New proxy resources are optimized. P03 initial portfolios were developed under each of the five price-policy scenarios. This portfolio fact sheet presents high-level information for P03-LN, the portfolio developed under a low gas / no CO_2 price-policy assumption.

PORTFOLIO SUMMARY

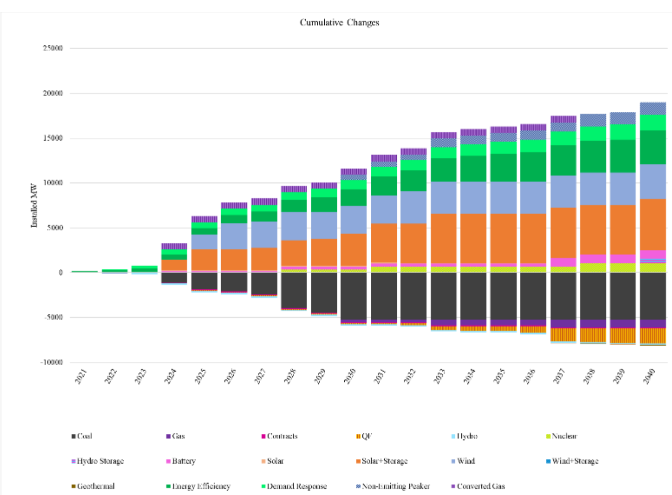
Risk-Adjusted PVRR ($m) ***$24,772***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

Thermal retirement assumptions for P03-LN are summarized in the following table.

Unit	Description
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2023
Hunter 2	Retire 2024
Hunter 3	Retire 2029
Huntington 1	Retire 2027
Huntington 2	Retire 2024
Jim Bridger 1	GC 2023, Retire 2037
Jim Bridger 2	GC 2023, Retire 2037
Jim Bridger 3	Retire 2029
Jim Bridger 4	Retire 2026
Naughton 1	Retire 2028
Naughton 2	Retire 2028
Naughton 3 GC	Retire 2029
Wyodak	Retire 2027

GC = gas conversion

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

P03 is a set of initial portfolios where all existing coal units are assumed to retire by 2030. New proxy resources are optimized. P03 initial portfolios were developed under each of the five price-policy scenarios. This portfolio fact sheet presents high-level information for P03-MN, the portfolio developed under a medium gas / no CO_2 price-policy assumption.

PORTFOLIO SUMMARY

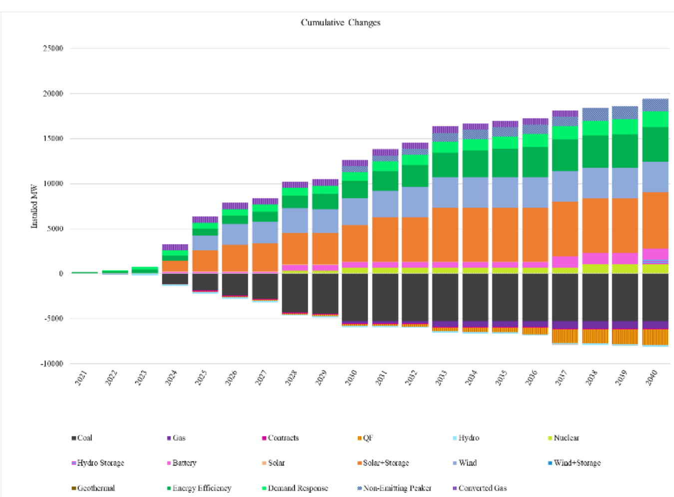
Risk-Adjusted PVRR ($m) $25,780

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

Thermal retirement assumptions for P03-MN are summarized in the following table.

Unit	Description
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2023
Hunter 2	Retire 2024
Hunter 3	Retire 2029
Huntington 1	Retire 2027
Huntington 2	Retire 2024
Jim Bridger 1	GC 2023, Retire 2037
Jim Bridger 2	GC 2023, Retire 2037
Jim Bridger 3	Retire 2029
Jim Bridger 4	Retire 2026
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3 GC	Retire 2029
Wyodak	Retire 2027

GC = gas conversion

Portfolio: Initial Portfolios (P03-MM)

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

P03 is a set of initial portfolios where all existing coal units are assumed to retire by 2030. New proxy resources are optimized. P03 initial portfolios were developed under each of the five price-policy scenarios. This portfolio fact sheet presents high-level information for P03-MM, the portfolio developed under a medium gas / medium CO_2 price-policy assumption.

PORTFOLIO SUMMARY

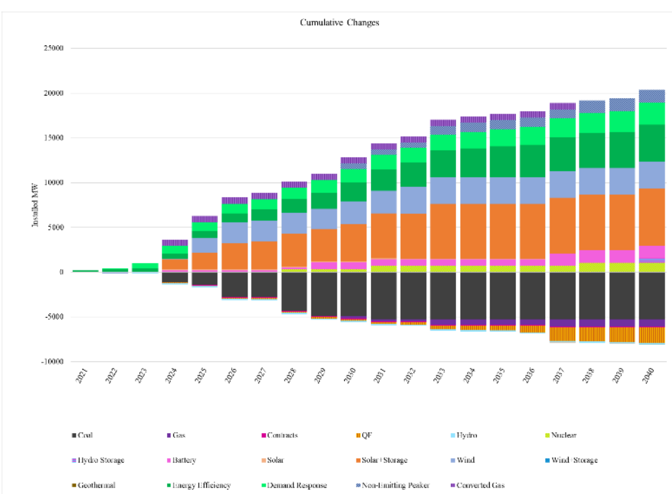
Risk-Adjusted PVRR ($m) ***$27,876***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

Thermal retirement assumptions for P03-MM are summarized in the following table.

Unit	Description
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2023
Hunter 2	Retire 2024
Hunter 3	Retire 2025
Huntington 1	Retire 2027
Huntington 2	Retire 2028
Jim Bridger 1	GC 2023, Retire 2037
Jim Bridger 2	GC 2023, Retire 2037
Jim Bridger 3	Retire 2025
Jim Bridger 4	Retire 2030
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3 GC	Retire 2029
Wyodak	Retire 2027

GC = gas conversion

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description
P03 is a set of initial portfolios where all existing coal units are assumed to retire by 2030. New proxy resources are optimized. P03 initial portfolios were developed under each of the five price-policy scenarios. This portfolio fact sheet presents high-level information for P03-HH, the portfolio developed under a high gas / high CO_2 price-policy assumption.

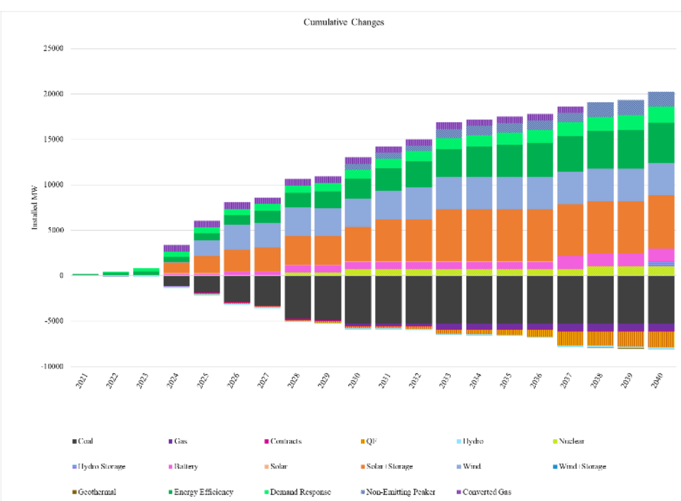
PORTFOLIO SUMMARY

Risk-Adjusted PVRR ($m) ***$29,030***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

Resource Portfolio
Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions
Thermal retirement assumptions for P03-HH are summarized in the following table.

Unit	Description
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2023
Hunter 2	Retire 2024
Hunter 3	Retire 2025
Huntington 1	Retire 2027
Huntington 2	Retire 2024
Jim Bridger 1	GC 2023, Retire 2037
Jim Bridger 2	GC 2023, Retire 2037
Jim Bridger 3	Retire 2029
Jim Bridger 4	Retire 2026
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3 GC	Retire 2029
Wyodak	Retire 2027

GC = gas conversion

Portfolio: Initial Portfolios (P03-SCGHG)

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

P03 is a set of initial portfolios where all existing coal units are assumed to retire by 2030. New proxy resources are optimized. P03 initial portfolios were developed under each of the five price-policy scenarios. This portfolio fact sheet presents high-level information for P03-SCGHG, the portfolio developed under a medium gas / social cost of greenhouse gas price-policy assumption.

PORTFOLIO SUMMARY

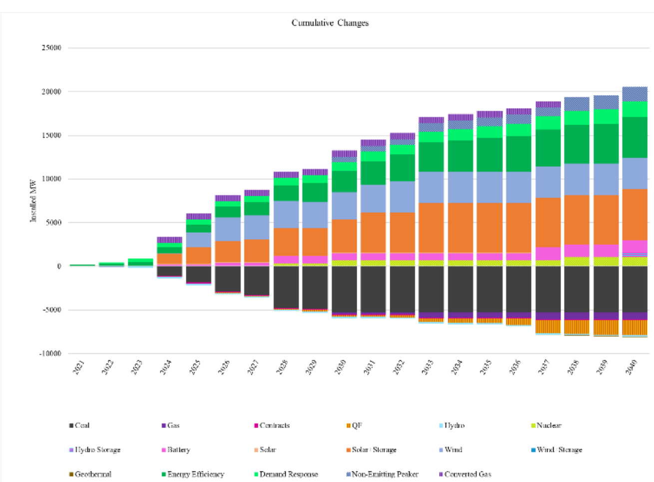
Risk-Adjusted PVRR ($m) $39,140

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

Thermal retirement assumptions for P03-SCGHG are summarized in the following table.

Unit	Description
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2023
Hunter 2	Retire 2024
Hunter 3	Retire 2025
Huntington 1	Retire 2027
Huntington 2	Retire 2024
Jim Bridger 1	GC 2023, Retire 2037
Jim Bridger 2	GC 2023, Retire 2037
Jim Bridger 3	Retire 2029
Jim Bridger 4	Retire 2026
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3 GC	Retire 2029
Wyodak	Retire 2027

GC = gas conversion

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

BAU1 is a set of initial portfolios where all existing coal units are assumed to retire at end-of-life. New proxy resources are optimized. BAU1 initial portfolios were developed under each of the five price-policy scenarios. This portfolio fact sheet presents high-level information for BAU1-LN, the portfolio developed under a low gas / no CO_2 price-policy assumption.

PORTFOLIO SUMMARY

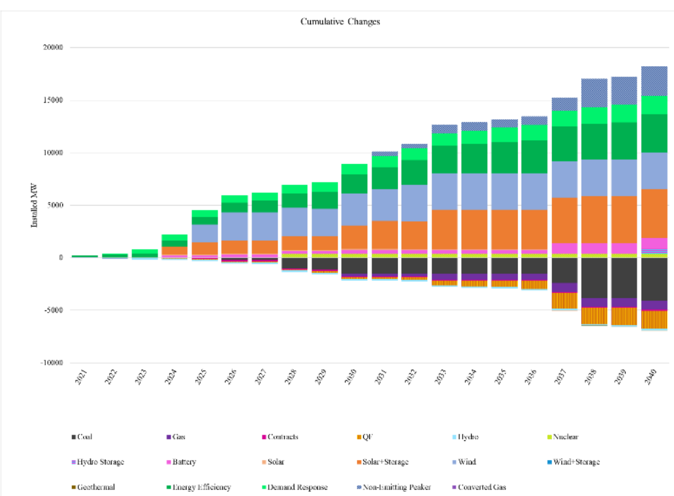
Risk-Adjusted PVRR ($m) $22,663

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

Thermal retirement assumptions for BAU1-LN are summarized in the following table.

Unit	Description
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2037
Jim Bridger 2	Retire 2037
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2029
Naughton 2	Retire 2029
Naughton 3 GC	Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Initial Portfolios (BAU1-MN)

Initial Portfolio-Development Fact Sheets

Portfolio Assumptions

Description

BAU1 is a set of initial portfolios where all existing coal units are assumed to retire at end-of-life. New proxy resources are optimized. BAU1 initial portfolios were developed under each of the five price-policy scenarios. This portfolio fact sheet presents high-level information for BAU1-MN, the portfolio developed under a medium gas / no CO_2 price-policy assumption.

Portfolio Summary

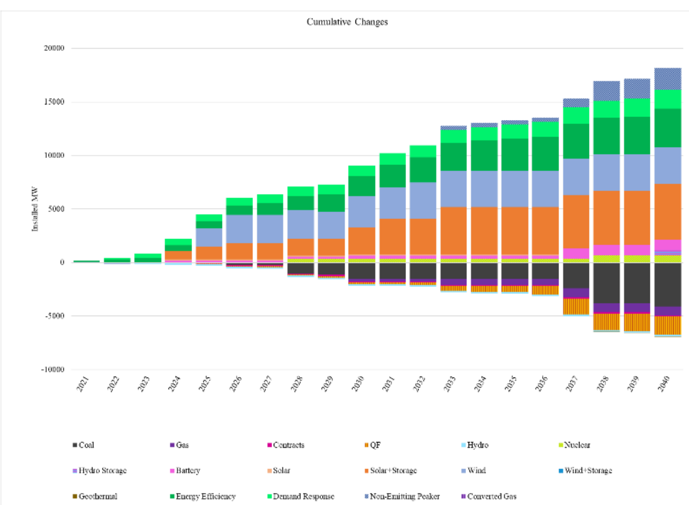
Risk-Adjusted PVRR ($m) ***$22,677***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

Thermal retirement assumptions for BAU1-MN are summarized in the following table.

Unit	**Description**
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2037
Jim Bridger 2	Retire 2037
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2029
Naughton 2	Retire 2029
Naughton 3 GC	Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

BAU1 is a set of initial portfolios where all existing coal units are assumed to retire at end-of-life. New proxy resources are optimized. BAU1 initial portfolios were developed under each of the five price-policy scenarios. This portfolio fact sheet presents high-level information for BAU1-MM, the portfolio developed under a medium gas / medium CO_2 price-policy assumption.

PORTFOLIO SUMMARY

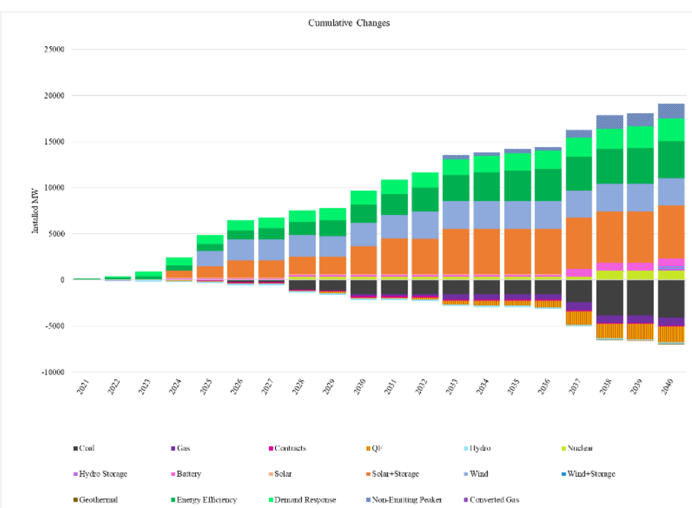
Risk-Adjusted PVRR ($m) $27,200

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

Thermal retirement assumptions for BAU1-MM are summarized in the following table.

Unit	Description
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2037
Jim Bridger 2	Retire 2037
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2029
Naughton 2	Retire 2029
Naughton 3 GC	Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Initial Portfolios (BAU1-HH)

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

BAU1 is a set of initial portfolios where all existing coal units are assumed to retire at end-of-life. New proxy resources are optimized. BAU1 initial portfolios were developed under each of the five price-policy scenarios. This portfolio fact sheet presents high-level information for BAU1-HH, the portfolio developed under a high gas / high CO_2 price-policy assumption.

PORTFOLIO SUMMARY

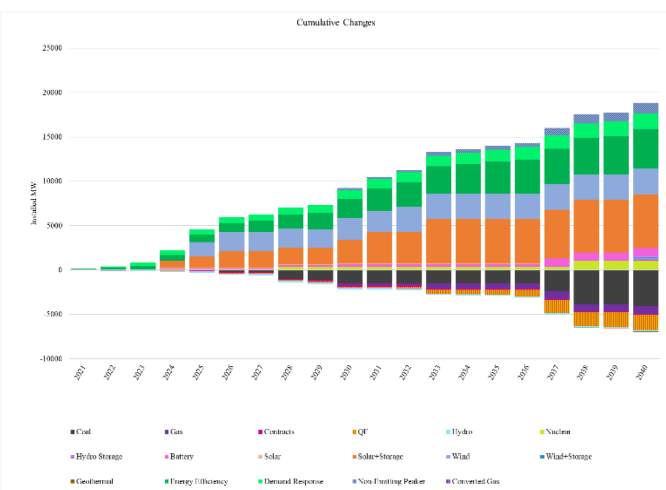
Risk-Adjusted PVRR ($m) $29,804

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

Thermal retirement assumptions for BAU1-HH are summarized in the following table.

Unit	**Description**
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2037
Jim Bridger 2	Retire 2037
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2029
Naughton 2	Retire 2029
Naughton 3 GC	Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Initial Portfolio-Development Fact Sheets

Portfolio Assumptions

Description

BAU1 is a set of initial portfolios where all existing coal units are assumed to retire at end-of-life. New proxy resources are optimized. BAU1 initial portfolios were developed under each of the five price-policy scenarios. This portfolio fact sheet presents high-level information for BAU1-SCGHG, the portfolio developed under a medium gas / social cost of greenhouse gas price-policy assumption.

Portfolio Summary

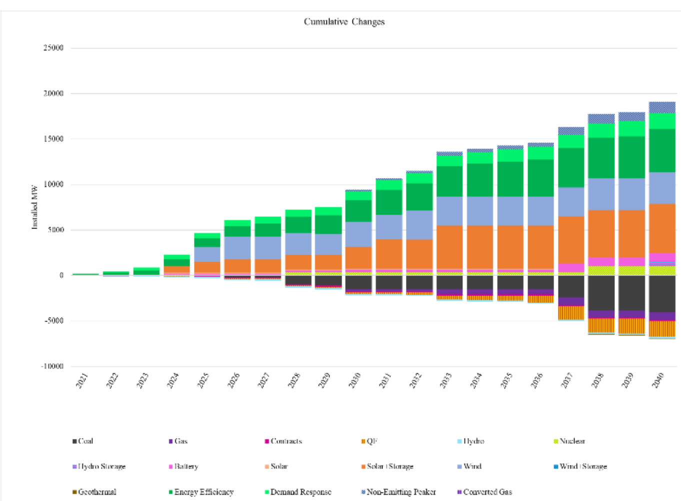
Risk-Adjusted PVRR ($m) ***$41,421***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

Thermal retirement assumptions for BAU1-SCGHG are summarized in the following table.

Unit	Description
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2037
Jim Bridger 2	Retire 2037
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2029
Naughton 2	Retire 2029
Naughton 3 GC	Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Initial Portfolios (BAU2-LN)

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

BAU2 is a set of initial portfolios where all existing coal units are assumed to retire consistent with the 2019 IRP preferred portfolio. New proxy resources are optimized. BAU2 initial portfolios were developed under each of the five price-policy scenarios. This portfolio fact sheet presents high-level information for BAU2-LN, the portfolio developed under a low gas / no CO_2 price-policy assumption.

PORTFOLIO SUMMARY

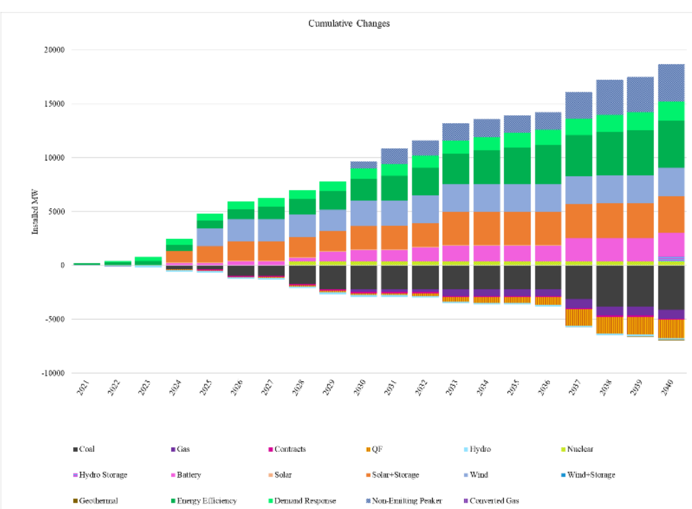
Risk-Adjusted PVRR ($m) ***$22,735***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

Thermal retirement assumptions for BAU2-LN are summarized in the following table.

Unit	Description
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2023
Jim Bridger 2	Retire 2028
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3 GC	Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

BAU2 is a set of initial portfolios where all existing coal units are assumed to retire consistent with the 2019 IRP preferred portfolio. New proxy resources are optimized. BAU2 initial portfolios were developed under each of the five price-policy scenarios. This portfolio fact sheet presents high-level information for BAU2-MN, the portfolio developed under a medium gas / no CO_2 price-policy assumption.

PORTFOLIO SUMMARY

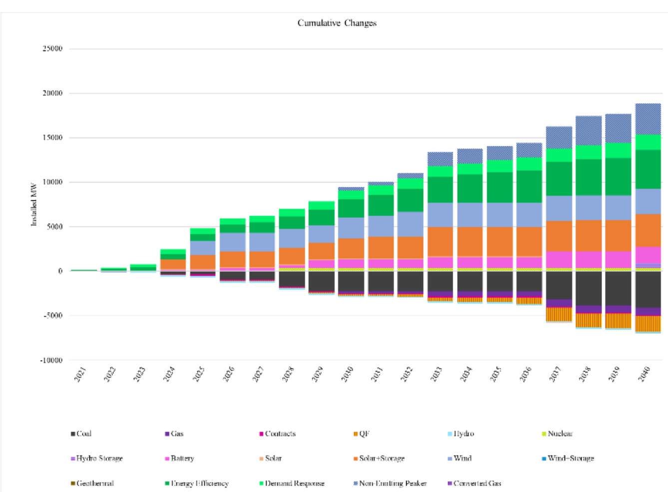
Risk-Adjusted PVRR ($m) ***$22,702***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

Thermal retirement assumptions for BAU2-MN are summarized in the following table.

Unit	Description
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2023
Jim Bridger 2	Retire 2028
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3 GC	Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Initial Portfolio (BAU2-MM)

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

BAU2 is a set of initial portfolios where all existing coal units are assumed to retire consistent with the 2019 IRP preferred portfolio. New proxy resources are optimized. BAU2 initial portfolios were developed under each of the five price-policy scenarios. This portfolio fact sheet presents high-level information for BAU2-MM, the portfolio developed under a medium gas / medium CO_2 price-policy assumption.

PORTFOLIO SUMMARY

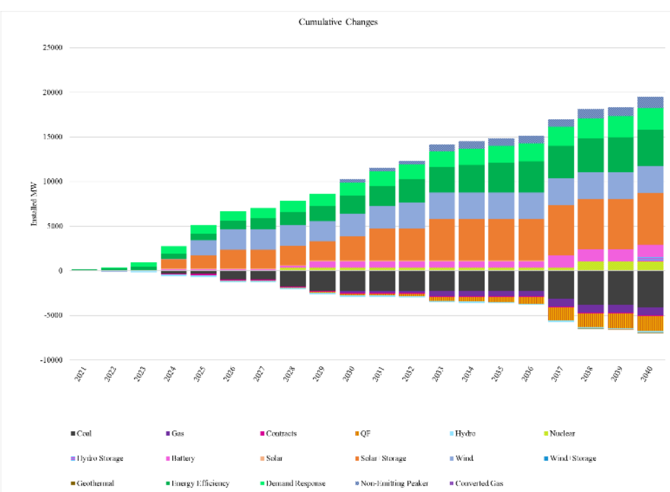
Risk-Adjusted PVRR ($m) ***$27,054***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

Thermal retirement assumptions for BAU2-MM are summarized in the following table.

Unit	**Description**
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2023
Jim Bridger 2	Retire 2028
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3 GC	Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

BAU2 is a set of initial portfolios where all existing coal units are assumed to retire consistent with the 2019 IRP preferred portfolio. New proxy resources are optimized. BAU2 initial portfolios were developed under each of the five price-policy scenarios. This portfolio fact sheet presents high-level information for BAU2-HH, the portfolio developed under a high gas / high CO_2 price-policy assumption.

PORTFOLIO SUMMARY

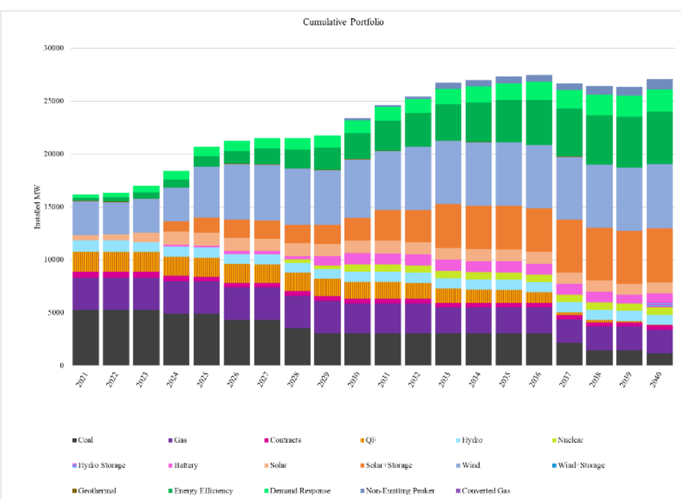
Risk-Adjusted PVRR ($m) $29,384

Incremental Transmission Upgrades

Description	***Year***	***Capacity***
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

Thermal retirement assumptions for BAU2-HH are summarized in the following table.

Unit	**Description**
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2023
Jim Bridger 2	Retire 2028
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3 GC	Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Initial Portfolios (BAU2-SCGHG)

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

BAU2 is a set of initial portfolios where all existing coal units are assumed to retire consistent with the 2019 IRP preferred portfolio. New proxy resources are optimized. BAU2 initial portfolios were developed under each of the five price-policy scenarios. This portfolio fact sheet presents high-level information for BAU2-SCGHG, the portfolio developed under a medium gas / social cost of greenhouse gas price-policy assumption.

PORTFOLIO SUMMARY

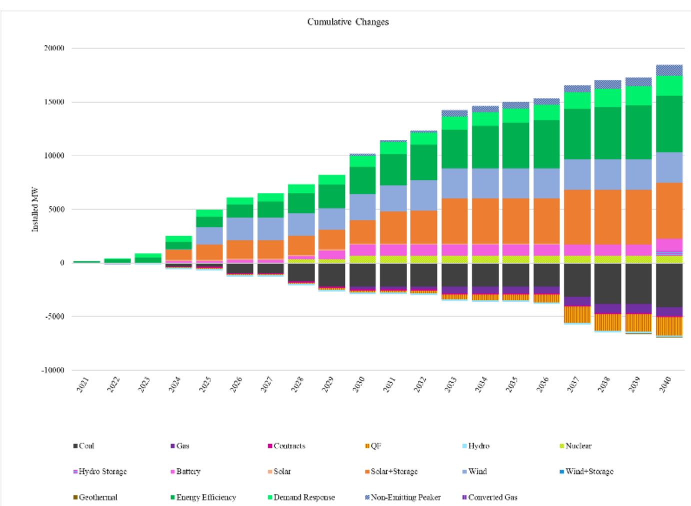
Risk-Adjusted PVRR ($m) ***$41,224***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

Thermal retirement assumptions for BAU2-SCGHG are summarized in the following table.

Unit	**Description**
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2023
Jim Bridger 2	Retire 2028
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3 GC	Retire 2029
Wyodak	Retire 2039

GC = gas conversion

P02 Variant Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

The P02a-JB 1-2 No GC portfolio is a variant of the P02-MM portfolio that eliminates the gas conversion of Jim Bridger Units 1 and 2.

PORTFOLIO SUMMARY

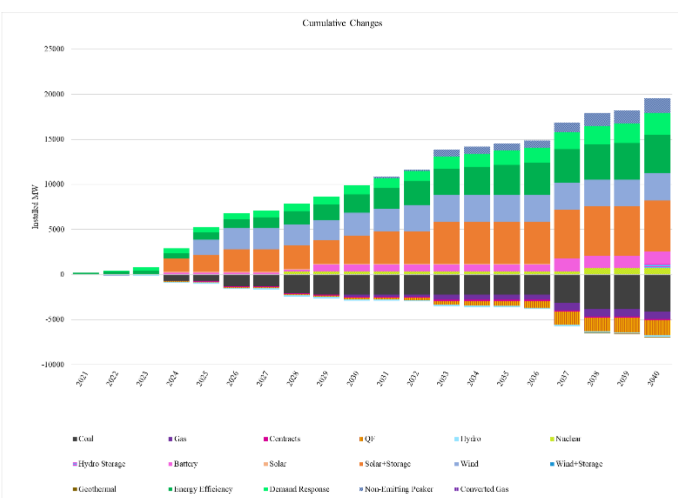
Risk-Adjusted PVRR ($m) ***$26,648***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

Thermal retirement assumptions for P02a-JB 1-2 No GC are summarized in the following table.

Unit	Description
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2023
Jim Bridger 2	Retire 2023
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3 GC	Retire 2029
Wyodak	Retire 2039

GC = gas conversion

P02 Variant Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

The P02b-No B2H portfolio is a variant of the P02-MM portfolio that eliminates the Boardman-to-Hemingway transmission line.

PORTFOLIO SUMMARY

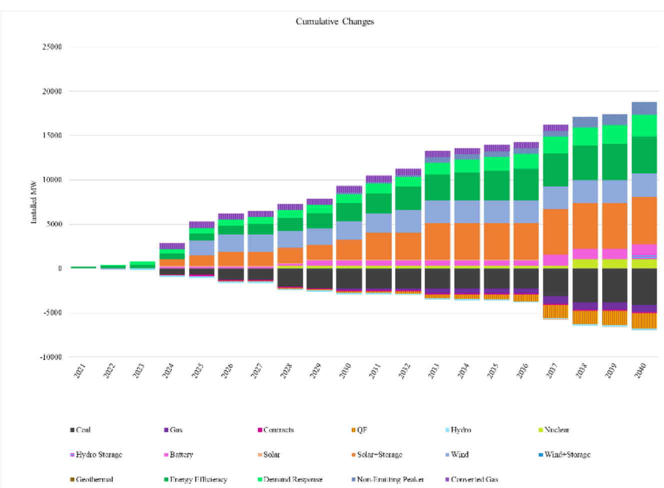
Risk-Adjusted PVRR ($m) $26,633

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

Thermal retirement assumptions for P02b-No B2H are summarized in the following table.

Unit	Description
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	GC 2024, Retire 2037
Jim Bridger 2	GC 2024, Retire 2037
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3 GC	Retire 2029
Wyodak	Retire 2039

GC = gas conversion

P02 Variant Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

The P02c-No GWS portfolio is a variant of the P02-MM portfolio that eliminates the Energy Gateway South (GWS) and D.1 transmission lines.

PORTFOLIO SUMMARY

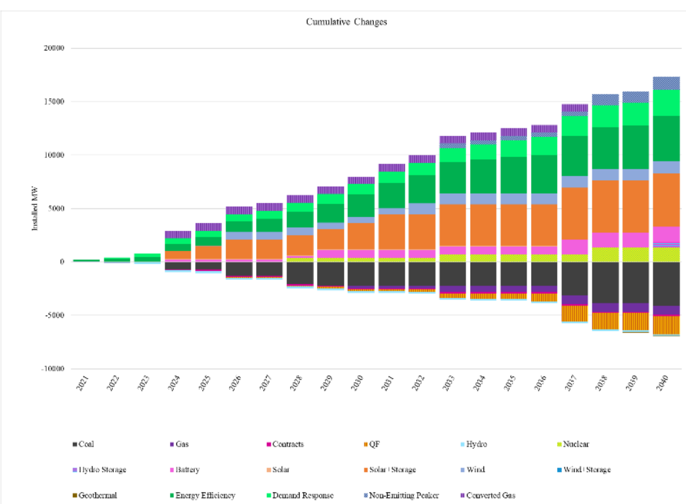
Risk-Adjusted PVRR ($m) ***$26,439***

Incremental Transmission Upgrades

Description	***Year***	***Capacity***
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

Thermal retirement assumptions for P02c-No GWS are summarized in the following table.

Unit	**Description**
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	GC 2024, Retire 2037
Jim Bridger 2	GC 2024, Retire 2037
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3 GC	Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: No RFP Bids (P02 Variants P02(d))

P02 Variant Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description
The P02d-No RFP portfolio is a variant of the P02-MM portfolio that eliminates all 2020 All-Source Request for Proposals final shortlist resources, including the Energy Gateway South (GWS) and D.1 transmission lines.

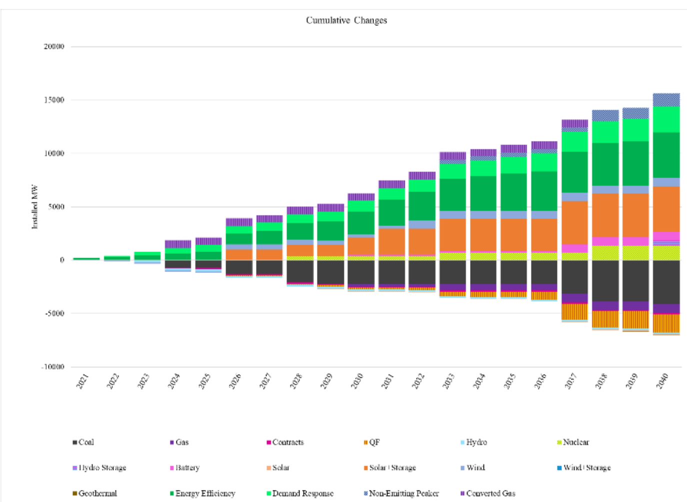
PORTFOLIO SUMMARY

Risk-Adjusted PVRR ($m) ***$27,445***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

Resource Portfolio
Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions
Thermal retirement assumptions for P02d-No RFP are summarized in the following table.

Unit	Description
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	GC 2024, Retire 2037
Jim Bridger 2	GC 2024, Retire 2037
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3 GC	Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: No Natrium Nuclear Project (P02 Variants P02(e))

P02 Variant Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description
The P02e-No Nuc portfolio is a variant of the P02-MM portfolio that eliminates the Natrium™ advanced nuclear demonstration project.

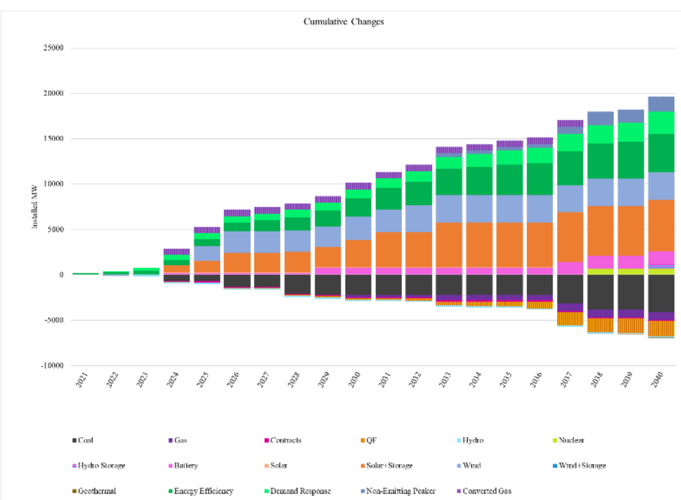
PORTFOLIO SUMMARY

Risk-Adjusted PVRR ($m) ***$26,337***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

Resource Portfolio
Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions
Thermal retirement assumptions for P02e-No Nuc are summarized in the following table.

Unit	Description
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	GC 2024, Retire 2037
Jim Bridger 2	GC 2024, Retire 2037
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3 GC	Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: No Naughton 2025 Retirement (P02 Variants P02(f))

P02 Variant Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description
The P02f-No Nau 25 portfolio is a variant of the P02-MM portfolio that maintains continued coal-fueled operation of Naughton Units 1 and 2 through the end of 2029, rather than retiring in 2025.

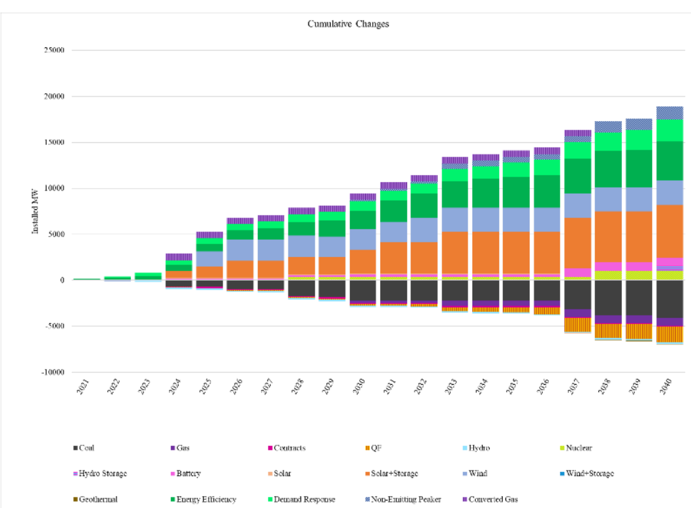
PORTFOLIO SUMMARY

Risk-Adjusted PVRR ($m) ***$26,245***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

Resource Portfolio
Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions
Thermal retirement assumptions for P02f-No Nau 25 are summarized in the following table.

Unit	Description
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	GC 2024, Retire 2037
Jim Bridger 2	GC 2024, Retire 2037
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2029
Naughton 2	Retire 2029
Naughton 3 GC	Retire 2029
Wyodak	Retire 2039

GC = gas conversion

P02 Variant Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

The P02g-CCUS portfolio is a variant of the P02-MM portfolio that forces a Carbon Capture Utilization and Sequestration (CCUS) retrofit on Dave Johnston Unit 4 in 2026, rather than retiring in 2027.

PORTFOLIO SUMMARY

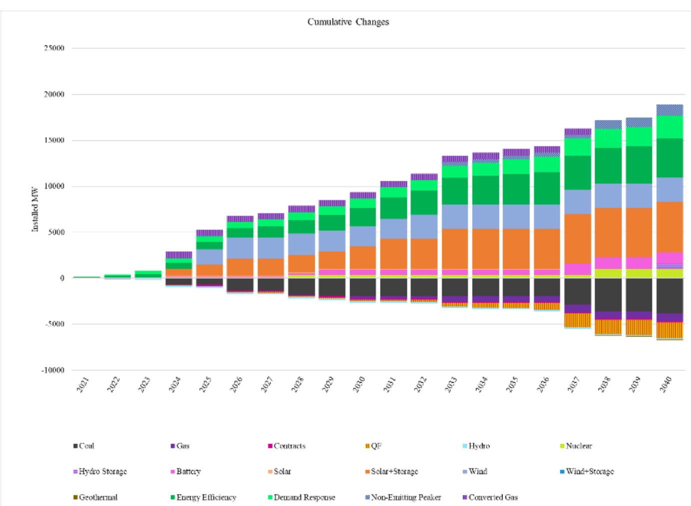
Risk-Adjusted PVRR ($m) ***$26,415***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

Thermal retirement assumptions for P02g-CCUS are summarized in the following table.

Unit	Description
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	CCUS 2026
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	GC 2024, Retire 2037
Jim Bridger 2	GC 2024, Retire 2037
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3 GC	Retire 2029
Wyodak	Retire 2039

CCUS = carbon capture and sequestration
GC = gas conversion

Portfolio: Jim Bridger 3 & 4 Early Retirement (P02 Variants P02(h))

P02 Variant Portfolio-Development Fact Sheets

Portfolio Assumptions

Description

The P02h-JB3-4 Retire portfolio is a variant of the P02-MM portfolio that forces Jim Bridger Units 3 and 4 to retire before 2030 with the most optimal timing as determined by the Plexos model.

Portfolio Summary

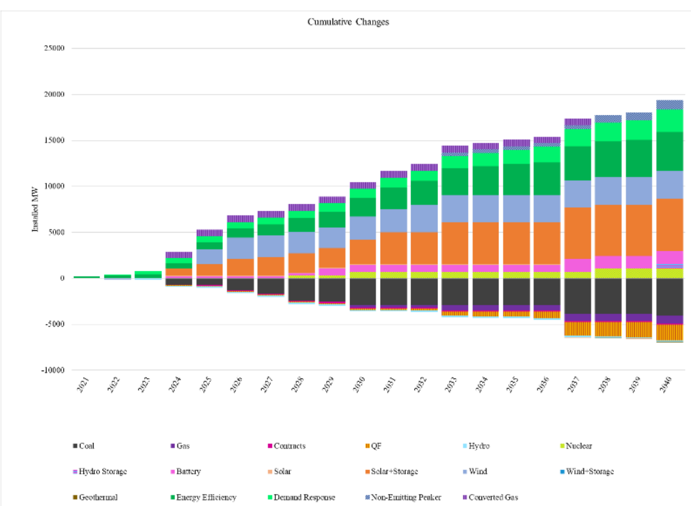
Risk-Adjusted PVRR ($m) ***$26,240***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

Thermal retirement assumptions for P02h-JB 3-4 Retire are summarized in the following table.

Unit	**Description**
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	GC 2024, Retire 2037
Jim Bridger 2	GC 2024, Retire 2037
Jim Bridger 3	Retire 2029
Jim Bridger 4	Retire 2026
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3 GC	Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Washington CETA Required Scenarios Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

Washington's Clean Energy Transformation Act (CETA) requires utilities to conduct specific scenarios as part of its integrated resource planning process. The Alternative Lowest Reasonable Cost scenario is required under WAC 480-100-620(10)(a) that instructs utilities to "describe the alternative lowest reasonable cost and reasonably available portfolio that the utility would have implemented if not for the requirement to comply" with CETA's Clean Energy Transformation Standards. Accounting for the retirement to include the social cost of greenhouse gas price policy in portfolio development, this is the alternative lowest cost portfolio, run under a medium gas / medium CO_2 price scenario.

PORTFOLIO SUMMARY

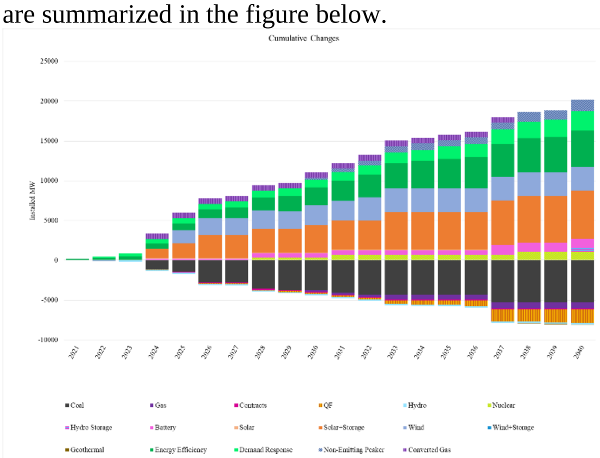
Risk-Adjusted PVRR ($m) $26,525

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

Thermal retirement assumptions for P02-SCGHG are summarized in the following table.

Unit	Description
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2023
Hunter 2	Retire 2024
Hunter 3	Retire 2025
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	GC 2023, Retire 2037
Jim Bridger 2	GC 2023, Retire 2037
Jim Bridger 3	Retire 2025
Jim Bridger 4	Retire 2030
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3 GC	Retire 2029
Wyodak	Retire 2031

GC = gas conversion

In the absence of a requirement to assume the social cost of greenhouse gas price policy during portfolio development, the alternative lowest reasonable cost portfolio is P02-MM (Initial Portfolio-Development Fact Sheet: P02-MM).

Portfolio: Climate Change Washington Required Portfolio

Washington CETA Required Scenarios Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

Washington's Clean Energy Transformation Act (CETA) requires utilities to conduct specific scenarios as part of its integrated resource planning process. The Climate Change scenario is required under WAC 480-100-620(10)(b) that instructs utilities to "incorporate the best science available to analyze impacts including, but not limited to, changes in snowpack, streamflow, rainfall, heating and cooling degree days, and load changes resulting from climate change."

PORTFOLIO SUMMARY

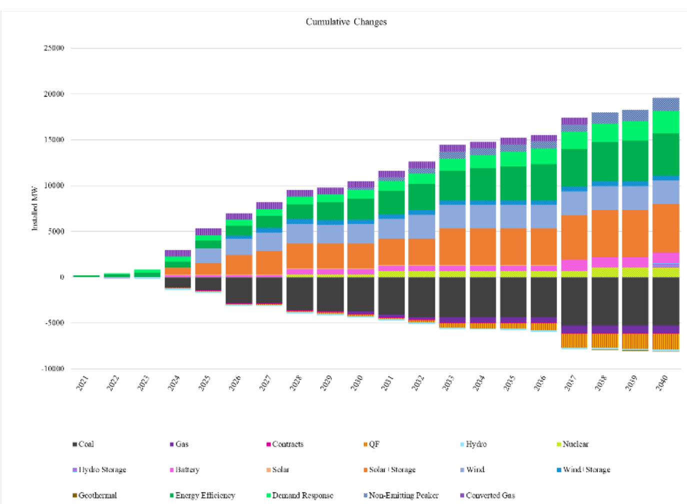
Risk-Adjusted PVRR ($m) ***$40,904***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

Thermal retirement assumptions for the Climate Change scenario are summarized in the following table.

Unit	**Description**
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2023
Hunter 2	Retire 2024
Hunter 3	Retire 2025
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	GC 2024, Retire 2037
Jim Bridger 2	GC 2024, Retire 2037
Jim Bridger 3	Retire 2025
Jim Bridger 4	Retire 2030
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3 GC	Retire 2029
Wyodak	Retire 2031

GC = gas conversion

Washington CETA Required Scenarios Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

Washington's Clean Energy Transformation Act (CETA) requires utilities to conduct specific scenarios as part of its integrated resource planning process. The Maximum Customer Benefit scenario is required under WAC 480-100-620(10)(c) instructs utilities to "model the maximum amount of customer benefits described in RCW 19.405.040(8) prior to balancing against other goals."

PORTFOLIO SUMMARY

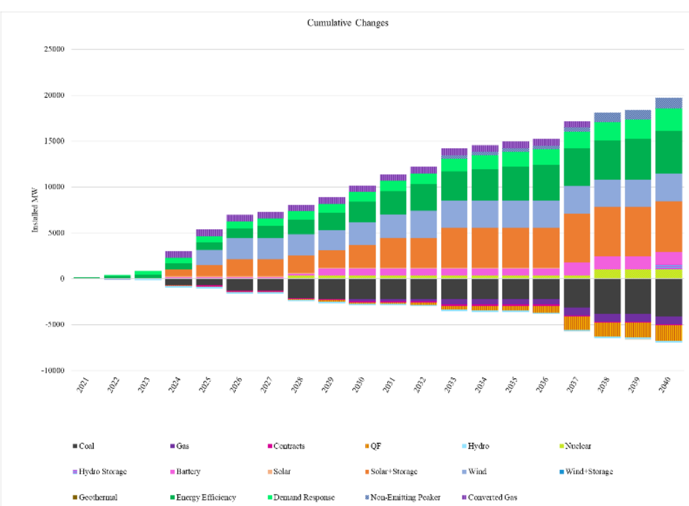
Risk-Adjusted PVRR ($m) ***$43,310***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

Thermal retirement assumptions for the Maximum Customer Benefit scenarios are summarized in the following table.

Unit	Description
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	GC 2024, Retire 2037
Jim Bridger 2	GC 2024, Retire 2037
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3 GC	Retire 2029
Wyodak	Retire 2039

GC = gas conversion

APPENDIX J – STOCHASTIC SIMULATION RESULTS

Introduction

This appendix reports additional results for the Monte Carlo production cost simulations conducted with the stochastic model. The results presented in Table J.1 through Table J.4 include stochastic results from the Medium Term (MT) model for the 2021 IRP preferred portfolio presented under five price-policy scenarios, four initial portfolios run through five price-policy scenarios, eight variant cases run through five price-policy scenarios and three Washington-required scenarios in accordance with WAC 480-100-620(10)(a)-(c).

Table J.5 and Figure J.1 present a 10-year incremental customer rate impact. Table J.6 and Figure J.2 present a 20-year incremental customer rate impact. Rate implications are more relevant over the near-term given biennial updates to the long-term 20-year planning horizon. During this time frame, portfolios and their associated costs are similar. Portfolio level system costs are a key factor in the portfolio selection process therefore, rate implications are not the primary key for portfolio selection. Distribution of costs among different classes is established in rate proceedings and nothing in the preferred portfolio would explicitly alter cost impacts among different classes of rate payers.

Table J.1 – MT Stochastic Mean PVRR, Preferred Portfolio

MT Stochastic PVRR ($ millions)						2021 to 2040	
Case	Stochastic Average	5th Percentile	90th Percentile	95th Percentile	Upper Tail	Upper Tail No Fixed Cost	Standard Deviation
P02-MM-CETA	25,233	24,911	25,457	25,476	25,538	7,106	178

Table J.2 – MT Stochastic Mean PVRR, Initial Portfolios

MT Stochastic PVRR ($ millions)						2021 to 2040	
Case	Stochastic Average	5th Percentile	90th Percentile	95th Percentile	Upper Tail	Upper Tail No Fixed Cost	Standard Deviation
P02-MM	25,213	24,881	25,419	25,460	25,505	7,198	178
P02-MM-CETA	25,233	24,911	25,457	25,476	25,538	7,106	178
P03-MM	26,903	26,516	27,158	27,203	27,235	5,677	210
BAU1-MM	25,866	25,554	26,071	26,112	26,152	6,715	174
BAU2-MM	25,927	25,603	26,134	26,171	26,213	6,744	176
P02-LN	21,508	21,209	21,684	21,737	21,805	5,093	160
P02-MM-LN	22,190	21,972	22,318	22,330	22,348	4,042	114
P02-MM-CETA-LN	22,296	22,085	22,433	22,440	22,459	4,026	114
P03-LN	24,069	23,772	24,236	24,270	24,360	3,327	152
BAU1-LN	21,957	21,721	22,104	22,120	22,142	4,206	126
BAU2-LN	21,987	21,648	22,175	22,239	22,324	5,188	177

Table J.2 Continued – MT Stochastic Mean PVRR, Initial Portfolios

P02-MN	21,312	20,989	21,544	21,571	21,625	4,745	181
P02-MM-MN	21,874	21,599	22,051	22,072	22,085	3,779	149
P02-MM-CETA-MN	22,005	21,736	22,198	22,203	22,227	3,795	149
P03-MN	24,818	24,483	25,027	25,065	25,100	3,310	179
BAU1-MN	21,862	21,592	22,042	22,060	22,069	3,568	149
BAU2-MN	21,833	21,466	22,079	22,117	22,198	4,904	200
P02-HH	27,670	27,256	27,950	28,011	28,094	10,098	235
P02-MM-HH	27,981	27,567	28,261	28,322	28,405	10,098	235
P02-MM-CETA-HH	28,032	27,617	28,334	28,369	28,473	10,041	234
P03-HH	27,902	27,451	28,258	28,270	28,355	7,267	259
BAU1-HH	28,265	27,850	28,544	28,610	28,685	9,998	231
BAU2-HH	27,992	27,573	28,289	28,342	28,428	10,094	241
P02-SC	37,189	36,587	37,731	37,763	38,034	18,649	405
P02-MM-SC	38,274	37,647	38,812	38,840	39,144	20,838	419
P02-MM-CETA-SC	38,316	37,697	38,841	38,898	39,209	20,777	415
P03-SC	36,952	36,371	37,454	37,494	37,734	16,668	386
BAU1-SC	38,689	38,048	39,245	39,278	39,560	21,035	426
BAU2-SC	38,564	37,940	39,123	39,171	39,449	21,115	430

Table J.3 – MT Stochastic Mean PVRR, P02 Variant Cases

MT Stochastic PVRR ($ millions)						2021 to 2040	
Case	**Stochastic Average**	**5th Percentile**	**90th Percentile**	**95th Percentile**	**Upper Tail**	**Upper Tail No Fixed Cost**	**Standard Deviation**
P02a-JB 1-2 No GC-MM	25,711	25,382	25,923	25,955	26,009	7,042	179
P02b-No B2h-MM	25,437	25,091	25,659	25,689	25,742	8,522	186
P02c-No GWS-MM	25,397	24,793	25,356	25,391	25,465	9,863	189
P02d-No RFP-MM	26,118	25,734	26,398	26,413	26,499	11,833	219
P02e-No Nuc-MM	25,335	24,996	25,546	25,585	25,636	7,703	180
P02f-No Nau 25-MM	25,178	24,839	25,382	25,428	25,474	7,435	179
P02g-CCUS-MM	25,349	25,016	25,558	25,592	25,634	6,482	177
P02h-JB 3-4 Retire-MM	25,257	24,922	25,475	25,508	25,557	6,510	181
P02a-JB 1-2 No GC-LN	22,742	22,529	22,876	22,886	22,911	3,943	114
P02b-No B2h-LN	22,107	21,883	22,251	22,262	22,280	5,060	120
P02c-No GWS-LN	21,442	20,957	21,324	21,333	21,366	5,764	120
P02d-No RFP-LN	21,632	21,350	21,801	21,842	21,900	7,234	149
P02e-No Nuc-LN	22,052	21,839	22,188	22,195	22,217	4,284	115
P02f-No Nau 25-LN	22,034	21,827	22,166	22,176	22,192	4,152	112
P02g-CCUS-LN	22,302	22,100	22,433	22,440	22,463	3,311	111
P02h-JB 3-4 Retire-LN	22,504	22,290	22,642	22,647	22,668	3,621	115

Table J.3 Continued – MT Stochastic Mean PVRR, P02 Variant Cases

P02a-JB 1-2 No GC-MN	22,345	22,085	22,536	22,544	22,573	3,606	148
P02b-No B2h-MN	21,943	21,659	22,141	22,156	22,180	4,960	157
P02c-No GWS-MN	21,497	20,953	21,443	21,450	21,493	5,890	157
P02d-No RFP-MN	21,986	21,637	22,221	22,273	22,329	7,663	191
P02e-No Nuc-MN	21,827	21,557	22,021	22,029	22,053	4,120	150
P02f-No Nau 25-MN	21,692	21,433	21,885	21,889	21,908	3,868	147
P02g-CCUS-MN	22,007	21,751	22,196	22,206	22,226	3,074	146
P02h-JB 3-4 Retire-MN	22,265	21,995	22,460	22,467	22,493	3,445	151
P02a-JB 1-2 No GC-HH	28,359	27,946	28,650	28,698	28,802	9,835	232
P02b-No B2h-HH	28,496	28,075	28,809	28,839	28,954	11,734	241
P02c-No GWS-HH	28,886	28,210	28,940	28,972	29,109	13,507	244
P02d-No RFP-HH	30,175	29,741	30,542	30,562	30,692	16,026	273
P02e-No Nuc-HH	28,229	27,818	28,529	28,573	28,670	10,737	236
P02f-No Nau 25-HH	28,010	27,598	28,300	28,349	28,439	10,400	233
P02g-CCUS-HH	27,950	27,536	28,249	28,289	28,389	9,237	231
P02h-JB 3-4 Retire-HH	27,754	27,342	28,059	28,094	28,199	9,151	235
P02a-JB 1-2 No GC-SC	38,539	37,911	39,088	39,142	39,438	20,471	425
P02b-No B2h-SC	39,289	38,656	39,823	39,890	40,216	22,996	427
P02c-No GWS-SC	40,504	39,876	41,068	41,151	41,519	25,917	442
P02d-No RFP-SC	43,168	42,478	43,758	43,833	44,196	29,530	471
P02e-No Nuc-SC	38,609	37,976	39,135	39,198	39,505	21,572	422
P02f-No Nau 25-SC	38,461	37,838	39,000	39,048	39,345	21,306	420
P02g-CCUS-SC	38,199	37,581	38,729	38,783	39,080	19,928	411
P02h-JB 3-4 Retire-SC	37,929	37,324	38,437	38,495	38,792	19,744	403

Table J.4 – MT Stochastic Mean PVRR, Washington Clean Energy Transmission Act (CETA) Required Scenarios Cases

MT Stochastic PVRR ($ millions)					2021 to 2040		
Case	Stochastic Average	5th Percentile	90th Percentile	95th Percentile	Upper Tail	Upper Tail No Fixed Cost	Standard Deviation
P02-MM-Alt Low Cost	25,648	25,281	25,918	25,931	25,999	6,614	203
P02-MM-Climate	37,391	36,753	37,963	38,032	38,271	20,010	426
P02-MM-Max Cust Benefit	40,668	40,049	41,200	41,252	41,553	23,189	414

Table J.5 – 10-year Incremental Customer Rate Impact

	10-year Incremental Customer Rate Impact (2021 - 2030)	
	Medium Gas, Medium CO2	
$ Millions	Difference from Top Portfolio	Rank
P02	0	1
P02-CETA	23	2
P03	304	5
BAU1	208	4
BAU2	132	3

Figure J.1 – 10-year Incremental Customer Rate Impact

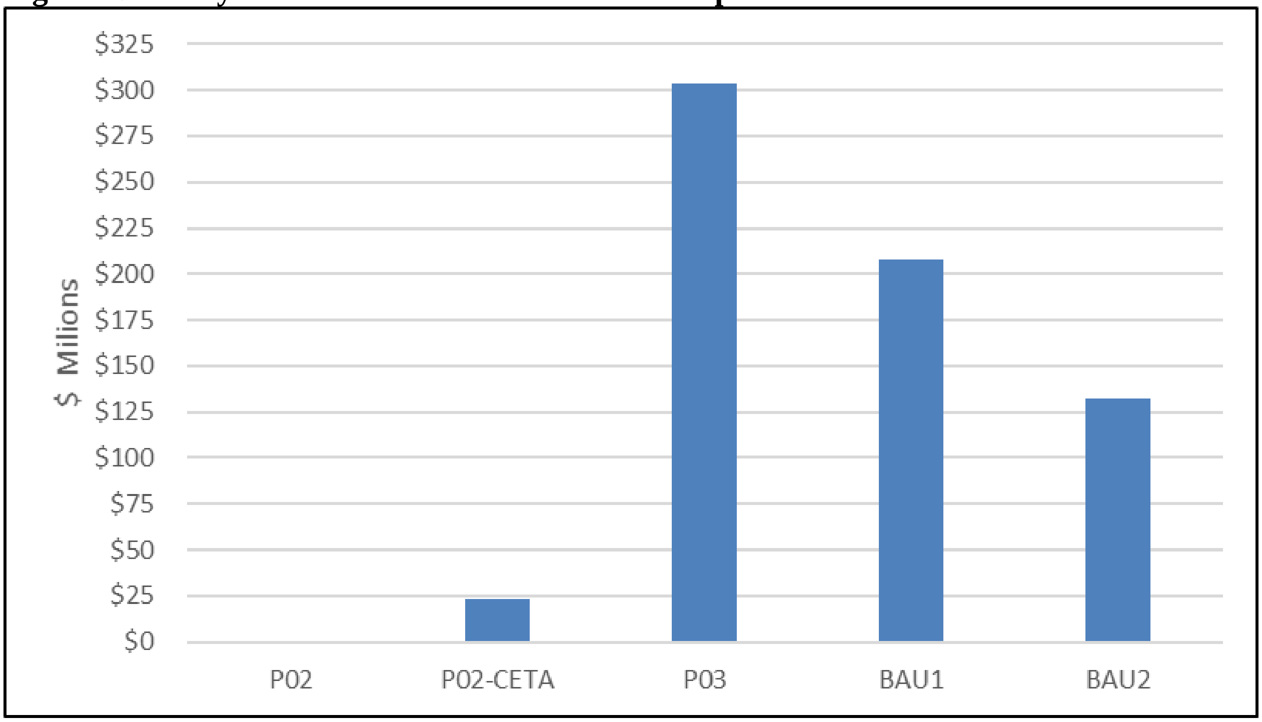
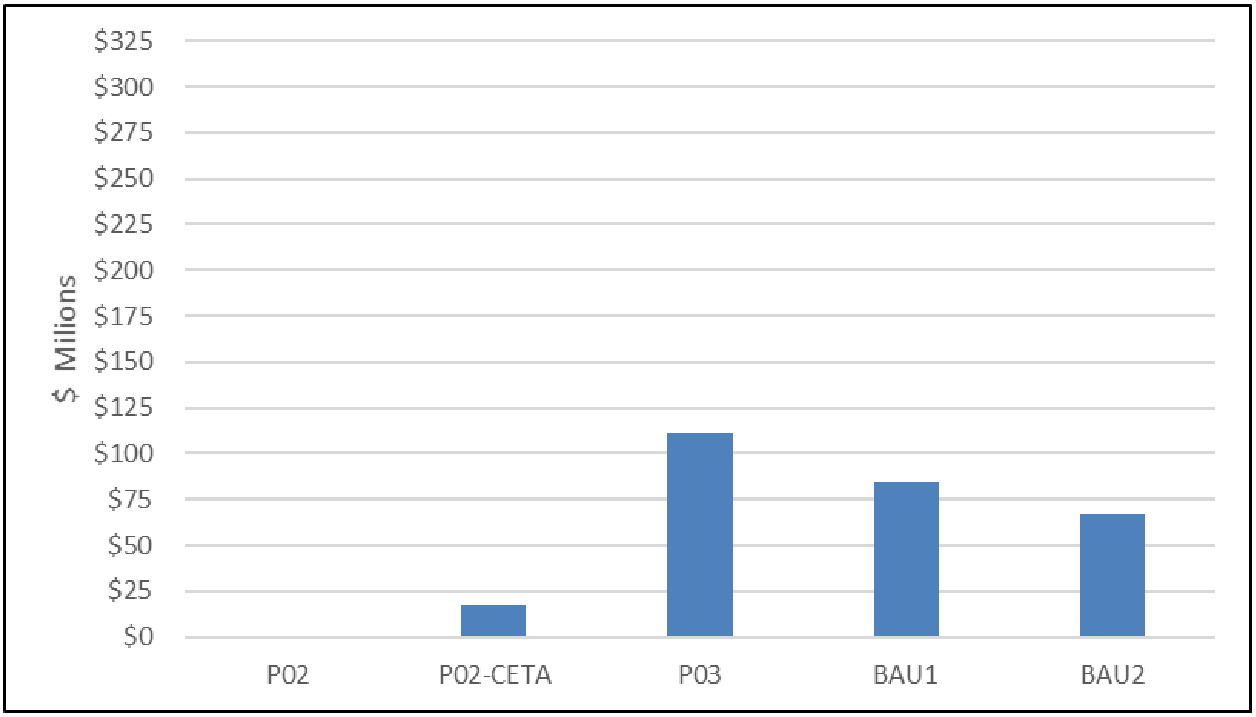


Table J.6 – 20-year Incremental Customer Rate Impact

	20-year Incremental Customer Rate Impact (2021 - 2040)	
	Medium Gas, Medium CO2	
$ Millions	**Difference from Top Portfolio**	**Rank**
P02	0	1
P02-CETA	17	2
P03	111	5
BAU1	85	4
BAU2	67	3

Figure J.2 – 20-year Incremental Customer Rate Impact


$325
$300
$275
$250
$225
$200
$175
$150
$125
$100
$75
$50
$25
$0
$ Milions
P02
P02-CETA
P03
BAU1
BAU2

APPENDIX K – CAPACITY CONTRIBUTION

Introduction

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

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

At the conclusion of the 2019 IRP, PacifiCorp recalculated 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 final CF Method analysis was performed using a portfolio that was very similar to the 2019 IRP preferred portfolio. For the reasons discussed above, this final CF Method analysis provides a reasonable estimate of capacity contribution value so long as the changes relative to the preferred portfolio are small, since in effect, the CF Method calculates the marginal capacity contribution of a one megawatt resource addition. Changes to the locations and quantities of wind, solar, and energy storage are key drivers of the marginal capacity contribution results.

[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

The capacity contribution analysis for the 2021 IRP is comparable to that in PacifiCorp's 2019 IRP in two key ways. First, rather than assigning a capacity contribution at the start of the analysis, the hourly reliability of portfolios was assessed to identify periods of shortfalls. Second, a final CF Method analysis was performed using a portfolio that is similar to the 2021 IRP preferred portfolio. The final CF Method analysis for the 2021 IRP is presented in this Appendix.

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 50-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.

Final CF Method Results

The final CF Method results described below provide a reasonable capacity contribution value so long as the changes relative to the preferred portfolio are small, since in effect, the CF Method calculates the marginal capacity contribution of a one-megawatt resource addition. Please note that marginal capacity contribution values reported herein are applicable to small incremental or

[2] In the past, PacifiCorp assumed that the first hour of any shortfall would be covered as part of its participation in the Northwest Power Pool (NWPP) reserve sharing agreement, which allows a participant to receive energy from other participants within the first hour of a contingency event. While this reserve sharing remains in effect, shortfalls in the 2021 IRP are much more likely to result from changes in load, renewable resource output, or energy storage limitations, and not in the first hour after a contingency event occurs. In light of this, PacifiCorp's 2021 IRP analysis no longer excludes 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.

decremental changes relative to the composition of the IRP preferred portfolio in 2030 and do not represent the average capacity contribution for each of the megawatts of a given resource type included in the preferred portfolio. In general, wind, solar, and energy storage have declining marginal capacity contribution values as the quantity of a given resource type increases. This results in average capacity contribution values that exceed the marginal capacity contribution values reported herein.

Table K.1 – Final CF Method Capacity Contribution Values for Wind, Solar, and Storage

	Capacity Factor (%)	Capacity Contribution (%)	
Summer/Winter:	**Annual**	**S**	**W**
Solar			
Idaho Falls, ID	28%	14%	7%
Lakeview, OR	29%	13%	18%
Milford, UT	32%	15%	7%
Yakima, WA	25%	9%	4%
Rock Springs, WY	30%	14%	13%
Wind			
Pocatello, ID	37%	33%	39%
Arlington, OR	37%	46%	17%
Monticello, UT	29%	14%	42%
Goldendale, WA	37%	47%	21%
Medicine Bow, WY	44%	30%	32%
Stand-alone Storage			
2-hour duration		49%	75%
4-hour duration		74%	90%
9-hour duration		90%	96%

Table K.2 – Final CF Method Capacity Contribution Values for Solar Combined with Storage

	Capacity Factor (%)	Capacity Contribution (%)	
Summer/Winter:	**Annual**	**S**	**W**
Solar & 100% x 4-hour Storage			
Idaho Falls, ID	28%	81%	92%
Lakeview, OR	29%	82%	93%
Milford, UT	32%	80%	95%
Yakima, WA	25%	79%	91%
Rock Springs, WY	30%	80%	94%

The above CF Method results are from a one-year study period (2030) and shortfall events are identified separately for every hour in that period. The details of the wind and solar resource modeling in the study period are important for interpreting 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 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 are 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

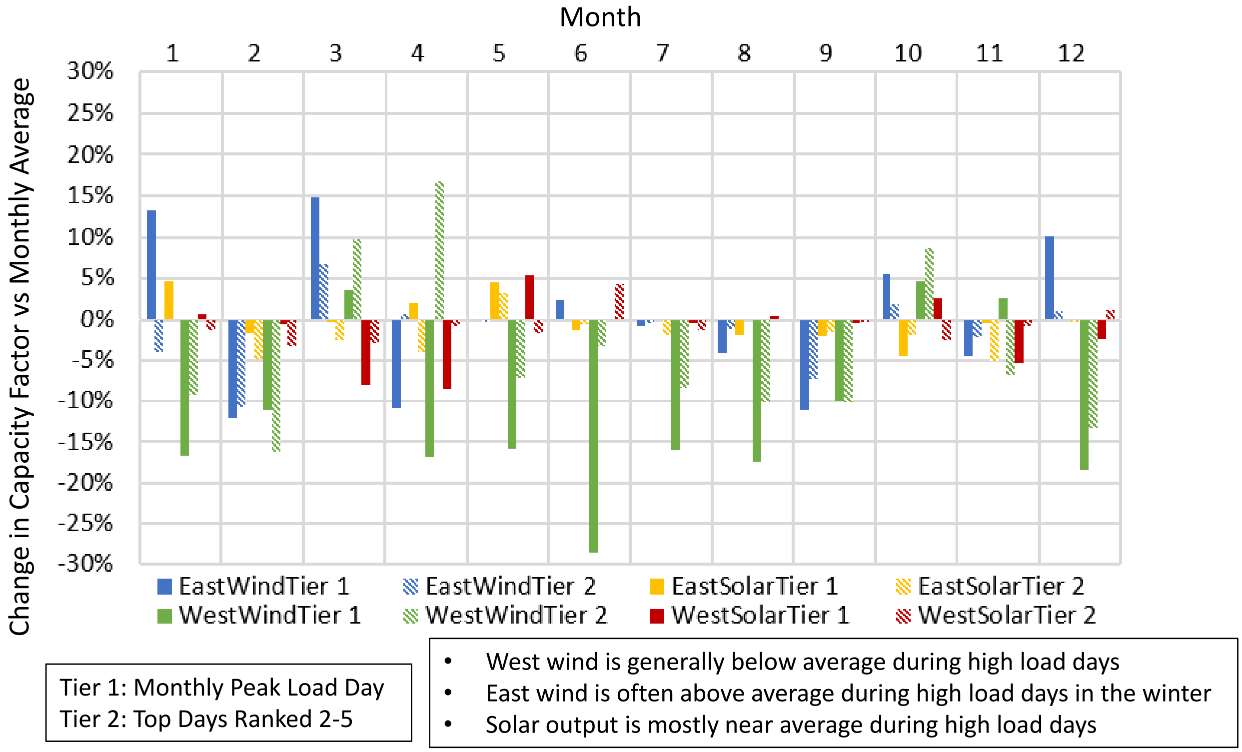
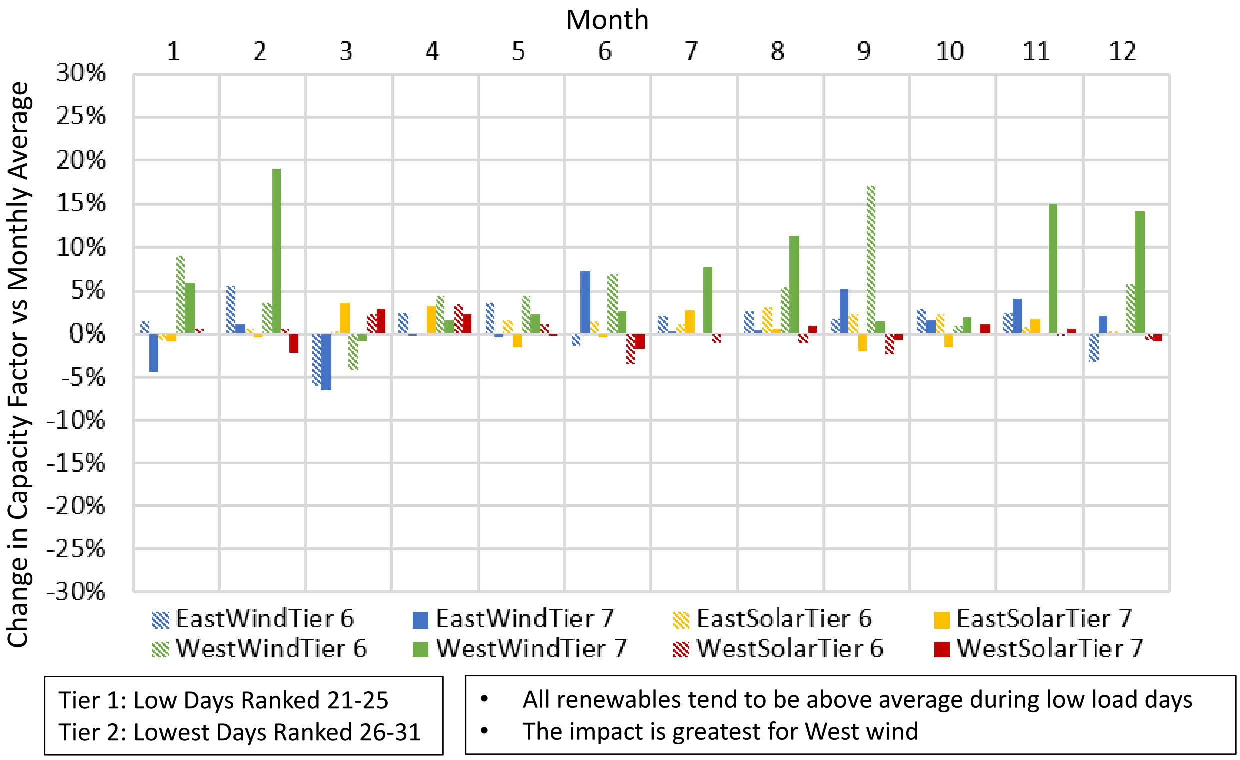


Figure K.2 – Renewable Resources vs. Low Load Conditions



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 2021 IRP. Instead, PacifiCorp developed 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 days 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

Guidehouse, formerly known as Navigant Consulting, Inc., 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 2021 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 Long-Term Resource Assessment (2021-2040)

Prepared for:

PacifiCorp

Prepared by:
Shalom Goffri
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June 19th, 2020

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June 19th, 2020

EXECUTIVE SUMMARY

Navigant Consulting, Inc. (Navigant) prepared this Private Generation Long-term Resource Assessment on behalf of PacifiCorp. In this study private generation (PG) sources provide customer-sited (behind the meter) energy generation and are generally of relatively small size, generating less than the amount of energy used at a location. The purpose of this study is to support PacifiCorp's 2019 Integrated Resource Plan (IRP) by projecting the level of private generation resources PacifiCorp's customers might install over the next twenty years under base, low, and high penetration scenarios.

This study builds on Navigant's previous assessments, [1, 2] which supported PacifiCorp's 2015, 2017, and 2019 IRP, incorporating updated load forecasts, market data, technology cost and performance projections. Navigant evaluated five private generation technologies in detail in this report:

1. Photovoltaic (Solar) Systems
2. Small Scale Wind
3. Small Scale Hydro
4. Reciprocating Engines
5. Micro-turbines

Project sizes were determined based on average customer load across the commercial, irrigation, industrial and residential customer classes.

Private generation technical potential [3] and expected market penetration[4] for each technology was estimated for each major customer class in each state in PacifiCorp's service territory. Shown in Figure 1, PacifiCorp serves customers in California, Idaho, Oregon, Utah, Washington, and Wyoming.

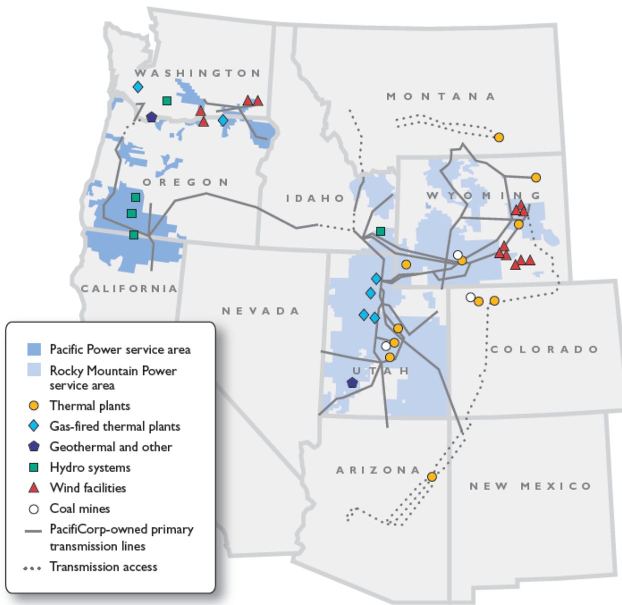
[1] Navigant, Distributed Generation Resource Assessment for Long-Term Planning Study, http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015IRP/2015IRPStudy/Navigant_Distributed-Generation-Resource-Study_06-09-2014.pdf.

[2] Navigant, Private Generation Long-Term Resource Assessment (2017-2036), http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/PacifiCorp_IRP_PG_Resource_Assessment_Final.pdf.

[3] Total resource potential factoring out resources that cannot be accessed due to non-economic reasons (i.e. land use restrictions, siting constraints and regulatory prohibitions), including those specific to each technology. Technical potential does not vary by scenario.

[4] Based on economic potential (technical potential that can be developed because it's not more expensive than competing options), estimates the timeline associated with the diffusion of the technology into the marketplace, considering the technology's relative economics, maturity, and development timeline.

Figure 1 PacifiCorp Service Territory[5]



Key Findings

Using PacifiCorp-specific information on customer size and retail rates in each state and public data sources for technology costs and performance, Navigant conducted a payback analysis and used Fisher-Pry[6] diffusion curves to determine likely market penetration for PG technologies from 2021 to 2040. This analysis was performed for typical commercial, irrigation, industrial and residential PacifiCorp customers in each state.

In the base scenario, Navigant estimates approximately 1.9 GW AC of PG capacity will be installed in PacifiCorp's territory from 2021-2040.[7] As shown in Figure 2, the low and high scenarios project a cumulative installed capacity of 1.0 GW AC and 2.9 GW AC, respectively. The main differences between scenarios include variation in technology costs, system performance, and electricity rate escalation assumptions. These assumptions are provided in Table 8.

[5] http://www.pacificorp.com/content/dam/pacificorp/doc/About_Us/Company_Overview/Service_Area_Map.pdf.

[6] Fisher-Pry are researchers who studied the economics of "S-curves", which describe how quickly products penetrate the market. They codified their findings based on payback period, which measures how long it takes to recoup initial high first costs with energy savings over time.

[7] All capacity numbers across all five resources are projected in MW-AC. Figures throughout the report are all in MW-AC.

Figure 2 Cumulative Market Penetration Results (MW AC), 2021 – 2040

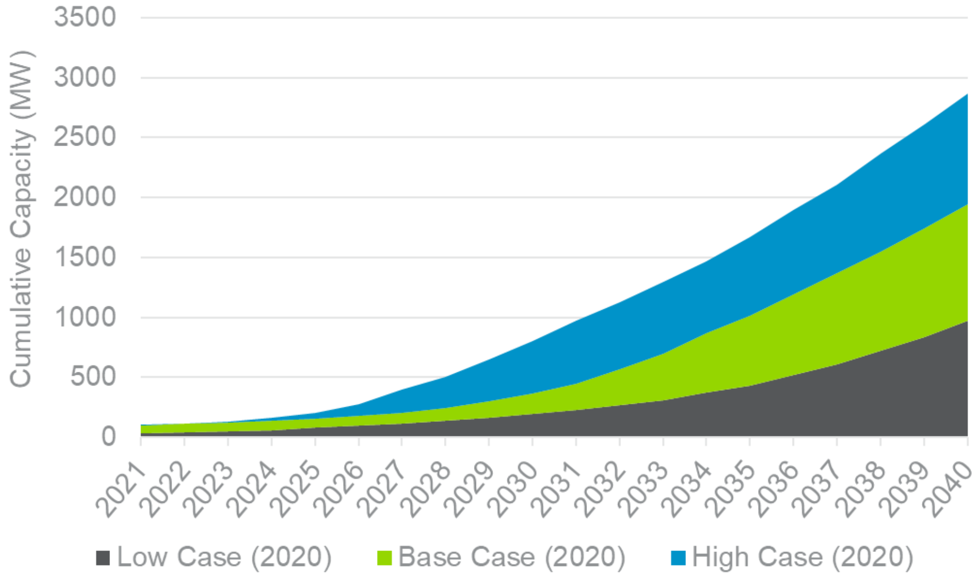


Figure 3 indicates that Utah and Oregon will drive most PG installations over the next two decades, largely because these two states are PacifiCorp's largest markets in terms of customers and sales[8]. Reference APPENDIX A for detailed state-specific customer data. In both states, PG installations are also driven by local tax credits and incentives. As displayed in Figure 4, solar represents the highest expected market penetration across the five technologies examined, with residential solar development leading the way, followed by non-residential solar (commercial, industrial, and irrigation). The Results section of the report contains results by state and technology for the high, base, and low scenarios.

Figure 3 also compares this study's results to Navigant's 2018 report. The two main factors that impacted the adoption results from 2018 to 2020 include: customer count and electric rate and policy.

Reference

Table 1 for a detailed comparison of the 2018 and 2020 adoption results. In the short-term, factors impacting adoption have a dampening effect on the market, yet more aggressive reduction in solar PV system costs longer-term, result in increased adoption over time. In 2038, the latest common year in the last two studies, cumulative adoption in the base case is around 1,500 MW in the 2020 study and around 1,300 MW in the 2018 study.

[8] The report reflects the regulatory modifications to the PG program in Utah, as included in Schedule 136 (Utah Docket 14-035-114)

Figure 3 Cumulative Market Penetration Results by State (MW AC), 2021 – 2040, Base Case

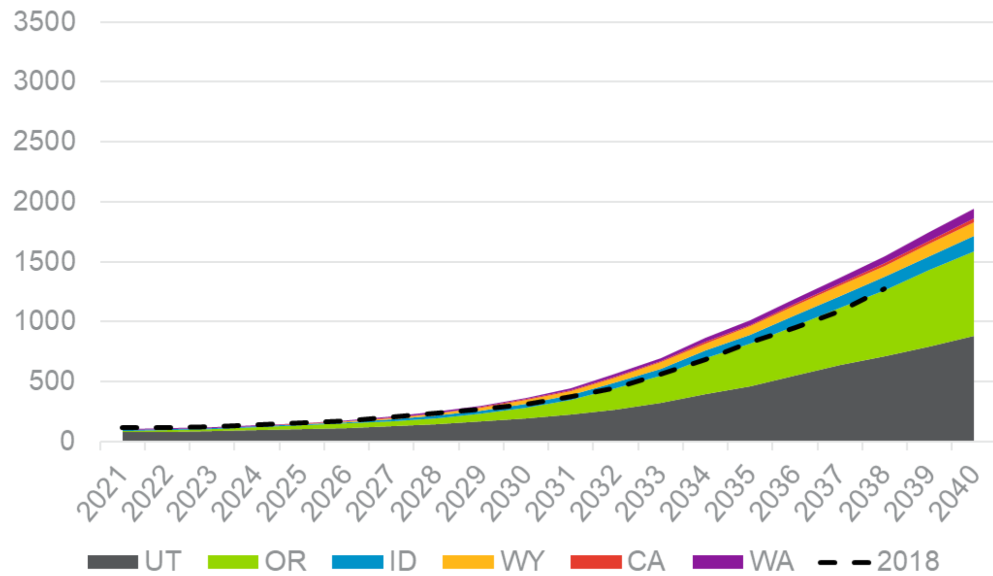
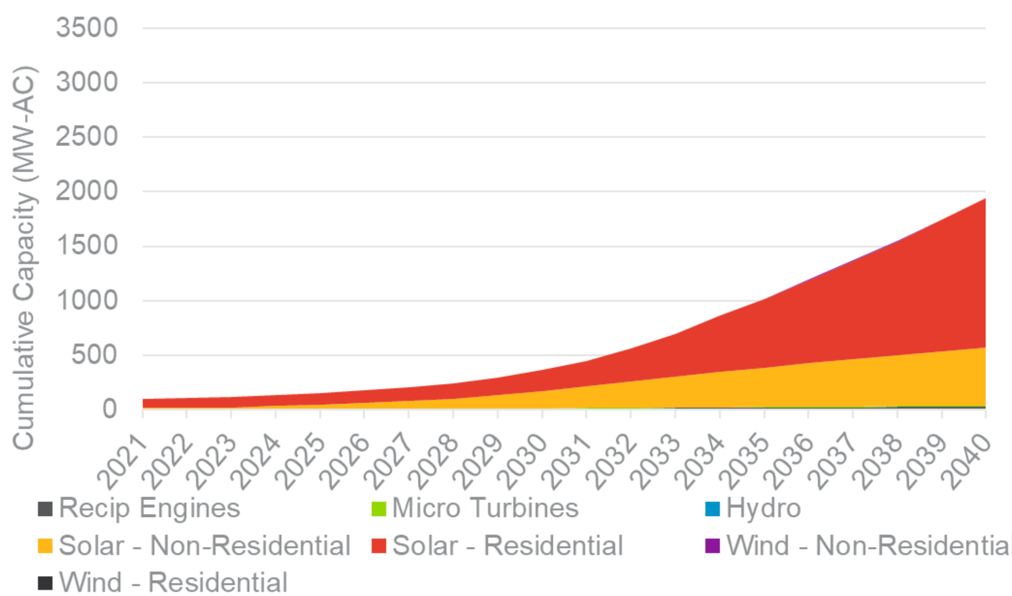


Figure 4 Cumulative Market Penetration Results by Technology (MW AC), 2021 – 2040, Base Case



The main factors that impacted the adoption results from 2018 to 2020 include: growth in customer count, retail rates, system cost and policy. In general, the rates used in this study changed relative to the 2018 study as PacifiCorp's ability to calculate more accurate offset rates has increased. For example, changes to California's net billing framework are captured in the offset rates. The technology cost and performance forecasts have not changed substantially since 2018. Solar PV policies in key states have not fluctuated as much as in previous studies, but policy changes in CA, UT and WA had a marginal impact on expected near-term and long-term adoption. These changes between the 2018 and 2020 analysis are detailed in

Table 1.

Table 1. Adoption Change from Electric Rate, System Cost and Policy Changes from 2018 to 2020

State	Estimated Adoption Change	Key Adoption Drivers
CA	**2038** – Market decreased from 48 MW to 22 MW	• Rates: Decrease (residential significantly, commercial and industrial marginally) • Solar PV Cost: Declines in the later years are more sustained • Policy: Change to net billing framework (captured in the offset rates) • Customer Count: increased 3%
ID	**2038** – Market remained consistent	• Rates: Decrease (residential, commercial, industrial) • Solar PV Cost: Declines in the later years are more sustained • Policy: No change • Customer Count: increased 10%
OR	**2038** – Market increased from 435 MW to 554 MW, with adoption shifting to later years which seems reasonable given incentive declines offset by cost declines in future years	• Rates: Decrease (commercial, industrial) • Solar PV Cost: Declines in the later years are more sustained • Policy: No change from Energy Trust incentives previously included. • Customer Count: increased 7.5%
UT	**2038** – Market increased from 560 MW to 646 MW. Key drivers include customer count increase, manual adjustment for 2021, and increase in commercial offset rates.	• Rates: Decrease (Residential, Industrial), Increase (Commercial); NEM reduction to around 90% of full rates • Solar PV Cost: Declines in the later years are more sustained • Policy: Incentive for residential solar PV declines to $400 in 2024 and $0 beyond; • The report reflects the regulatory modifications to the PG program in Utah, as included in Schedule 136 (Utah Docket 14-035-114) • Customer Count: increased 12%
WA	**2038** – Market increased from 60 MW to 76 MW	• Rates: Decrease (commercial, industrial) • Solar PV Cost: Declines in the later years are more sustained • Policy: Solar and wind FiT reduced rate for an 8-year period • Customer Count: increased 5.5%
WY	**2038** – Market decreased from 114 MW to 96 MW	• Rate: Small changes only • Solar PV Cost: Declines in the later years are more sustained • Policy: None • Customer Count: increased 2%

The impact of these factors, in aggregate, on PG adoption are shown in Figure 5. In the short-term, factors impacting adoption have a dampening effect on the market, yet more sustained declines in solar PV system costs in later years result in increased adoption over time. In 2036, the latest year in all three studies, cumulative adoption in the base case is around 1,200 MW in the 2020 study, around 1,000 MW in the 2018 study and around 1,200 in 2016. The consistency in cumulative adoption across all three studies indicates that the long-term adoption factors have not experienced significant, unexpected changes. In 2038, the latest year in the latest two studies, cumulative adoption in the base case is around 1,500 MW in the 2020 study and around 1,300 MW in the 2018 study, primarily driven by growth in PacifiCorp's customer count and changes to offset rates.

Figure 5 Cumulative Market Penetration Results by Scenario (MW AC), 2020 and 2018 Studies, 2021-2038

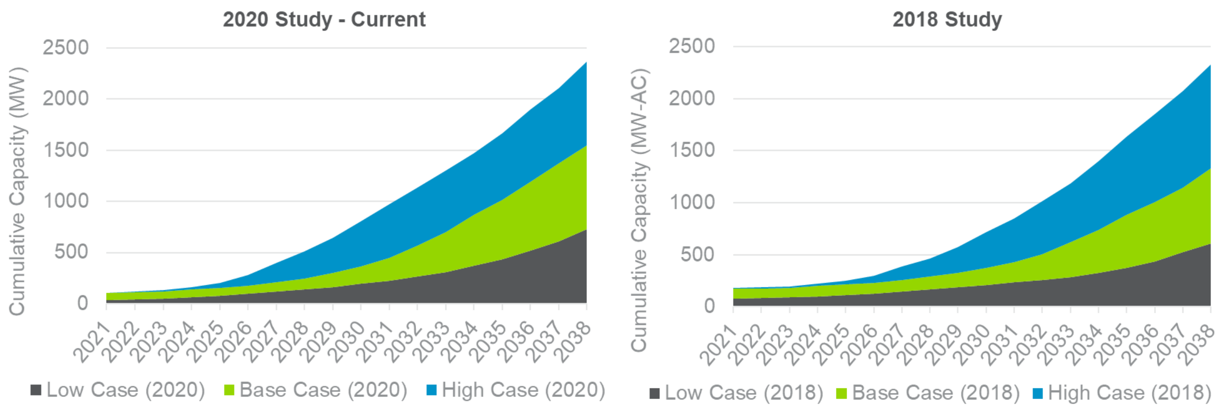
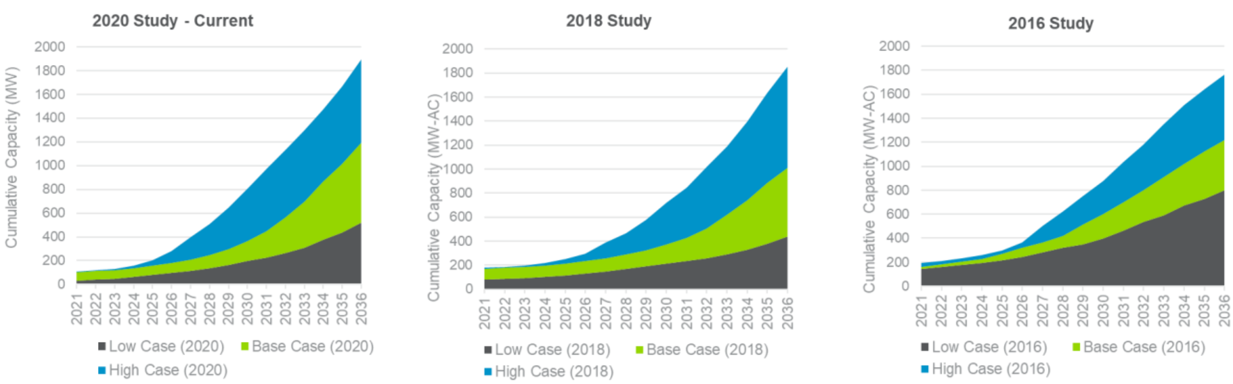


Figure 6 Cumulative Market Penetration Results by Scenario (MW AC), 2020, 2018 and 2016 Studies, 2021-2036



Report Organization

The report is organized as follows:

- Private Generation Market Penetration Methodology
- Results
- APPENDIX A: Customer Data
- APPENDIX B: System Capacity Assumptions
- APPENDIX C: Detailed Numeric Results

PRIVATE GENERATION MARKET PENETRATION METHODOLOGY

This section provides a high-level overview of the study methodology.

1.1 Methodology

In assessing the technical and market potential of each private generation (PG) resource and opportunity in PacifiCorp's service area, the study considered many key factors, including:

- Technology maturity, costs, and future cost projections
- Industry practices, current and expected
- Net metering policies
- Federal and state tax incentives
- Utility or third-party incentives
- O&M costs
- Historical performance, and expected performance projections
- Hourly PG Generation
- Consumer behavior and market penetration

1.2 Market Penetration Approach

The following five-step process was used to estimate the market penetration of PG resources in each scenario:

1. **Assess a Technology's Technical Potential:** Technical potential is the amount of a technology that can be physically installed without considering economics or other barriers to customer adoption. For example, technical potential assumes that photovoltaic systems are installed on all suitable residential roofs.
2. **Calculate Simple Payback Period for Each Year of Analysis:** From past work in projecting the penetration of new technologies, Navigant has found that Simple Payback Period is a key indicator of customer uptake. Navigant used all relevant federal, state, and utility incentives in its calculation of paybacks, incorporating their projected reduction and/or discontinuation over time, where appropriate.
3. **Project Ultimate Adoption Using Payback Acceptance Curves:** Payback Acceptance Curves estimate the percentage of a market that will ultimately adopt a technology, but do not factor in how long adoption will take.
4. **Project Market Penetration Using Market Penetration Curves:** Market penetration curves factor in market and technology characteristics, projecting the adoption timeline.
5. **Project Market Penetration under Different Scenarios.** In addition to the base case scenario, high and low case scenarios were created by varying cost, performance, and retail rate projections.[9]

[9] In the case of Utah, the Base and High cases for 2019 and 2020 solar PV installations were adjusted to reflect the capacity cap included within Schedule 136 (Utah Docket 14-035-114)

These five steps are explained in detail in the following sections.

1.3 Assess Technical Potential

Each technology considered has its own characteristics and data sources that influence the technical potential assessment; the amount of a technology that can be physically installed within PacifiCorp's service territory without considering economics or other barriers to customer adoption. For this Navigant used the number of customers, system size, and access factors by technology. Navigant escalated technical potentials at the same rate PacifiCorp projects its sales will change over time. This also does not account for the electrical system's ability to integrate private generation.

1.4 Simple Payback

For each customer class (i.e., residential, commercial, irrigation and industrial), technology, and state, Navigant calculated the simple payback period using the following formula:

Simple Payback Period *= (Net Initial Costs) / (Net Annual Savings)*

Net Initial Costs *= Installed Cost – Federal Incentives – Capacity-Based Incentives*(1 – Tax Rate)*[10]

Net Annual Savings *= Annual Energy Bills Savings + (Performance Based Incentives – O&M Costs – Fuel Costs) * (1 – Tax Rate)*[10]

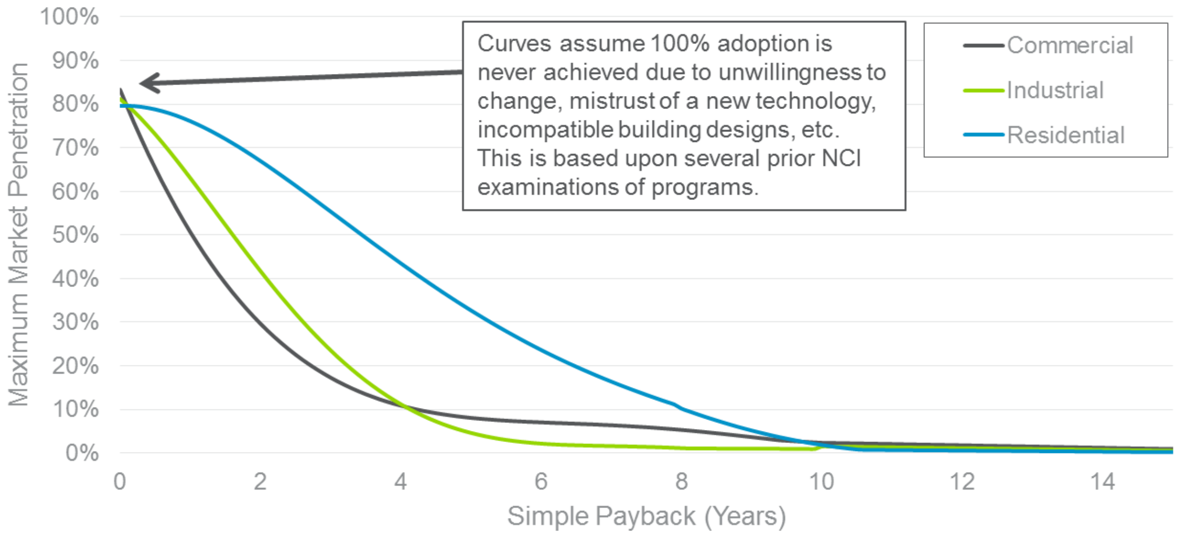
- *Federal tax credits can be taken against a system's full value if other (i.e. utility or state supplied) capacity-based or performance-based incentives are considered taxable.*
- *Navigant's Market Penetration model calculates first year simple payback assuming new installations for each year of analysis.*
- *For electric bills savings, Navigant conducted an 8,760-hourly analysis to consider actual rate schedules, actual output profiles, and demand charges. System performance assumptions are listed in Section 1.3 above. Solar performance and wind performance profiles were calculated for representative locations within each state based on the National Renewable Energy Laboratory (NREL) System Advisory Model (SAM). Building load profiles were provided by PacifiCorp and were scaled to match the average electricity usage for each customer class based on billing data.*

[10] Applies to all non-federal incentives regardless if it's coming from the state or another state-based entity.

1.5 Payback Acceptance Curves

For private generation technologies, Navigant used the following payback acceptance curves to model market penetration of PG sources from the retail customer's perspective.

Figure 7 Payback Acceptance Curves



Source: Navigant Consulting based upon work for various utilities, federal government organizations, and state/local organizations. The curves were developed from customer surveys, mining of historical program data, and industry interviews.

These payback curves are based upon work for various utilities, federal government organizations, and state local organizations. They were developed from customer surveys, mining of historical program data, and industry interviews.[11] Given a calculated payback period, the curve predicts the level of maximum market penetration. For example, if the technical potential is 100 MW, the 3-year commercial payback predicts that 15% of this technical potential, or 15 MW, will ultimately be achieved over the long term.

1.6 Market Penetration Curves

To determine the future PG market penetration within PacifiCorp's territory, Navigant modeled the growth of PG technologies from 2020 thru 2040. The model is a Fisher-Pry based technology adoption model that calculates the market growth of PG technologies. It uses a lowest-cost approach to consumers to develop expected market growth curves based on maximum achievable market penetration and market saturation time, as defined below.[12]

- **Market Penetration** – The percentage of a market that purchases or adopts a specific product or technology. The Fisher-Pry model estimates the achievable market penetration based on characteristics of the technology and industry. Market penetration curves (sometimes called S-

[11] Payback acceptance curves are based on a broad set of data from across the United States and may not predict customer behavior in a specific market (e.g. Utah customers may install solar at different paybacks than indicated by the payback acceptance curves due to market specific reasons).

[12] Michelfelder and Morrin, "Overview of New Product Diffusion Sales Forecasting Models" provides a summary of product diffusion models, including Fisher-Pry. Available: law.unh.edu/assets/images/uploads/pages/ipmanagement-new-product-diffusion-sales-forecasting-models.pdf

curves) are well established tools for estimating diffusion or penetration of technologies into the market. Navigant applies the market penetration curve to the payback acceptance curve shown in Figure 7 Payback Acceptance Curves.

- **Market Saturation Time** – The duration in years for a technology to increase market penetration from around 10% to 80%.

The Fisher-Pry model estimates market saturation time based on 12 different market input factors; those with the most substantial impact include:

- **Payback Period** – Years required for the cumulative cost savings to equal or surpass the incremental first cost of equipment.
- **Market Risk** – Risk associated with uncertainty and instability in the marketplace, which can be due to uncertainty regarding cost, industry viability, or even customer awareness, confidence, or brand reputation. An example of a high market risk environment is a jurisdiction lacking long-term, stable guarantees for incentives.
- **Technology Risk** – Measures how well-proven and the availability of the technology. For example, technologies that are completely new to the industry have a higher risk, whereas technologies that are only new to a specific market (or application) and have been proven elsewhere have lower risk.
- **Government Regulation** – Measure of government involvement in the market. A government-stated goal is an example of low government involvement, whereas a government mandated minimum efficiency requirement is an example of high involvement, having a significant impact on the market.

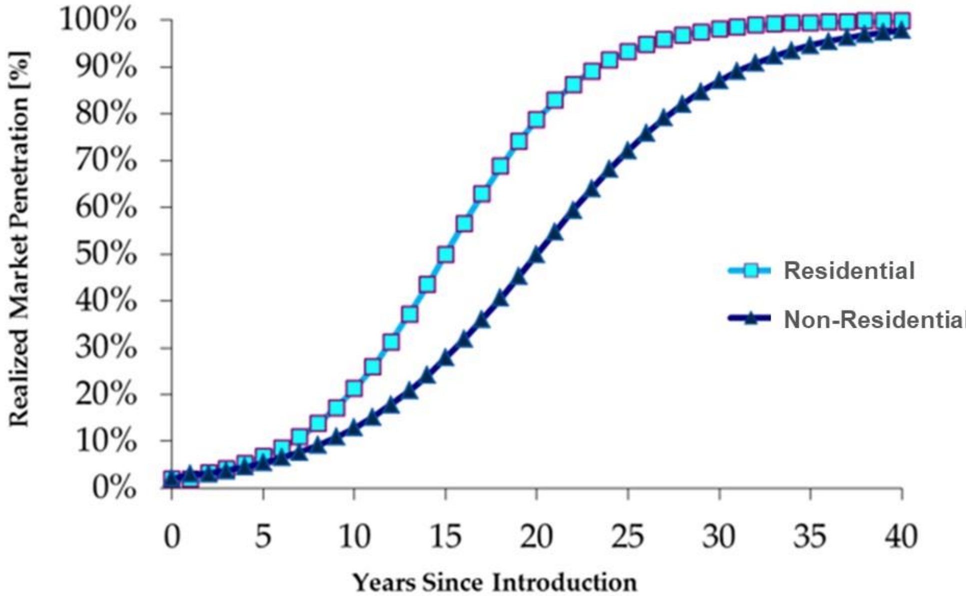
The model uses these factors to determine market growth instead of relying on individual assumptions about annual market growth for each technology or various supply and/or demand curves that may sometimes be used in market penetration modeling. With this approach, the model does not account for other more qualitative limiting market factors, such as the ability to train quality installers or manufacture equipment at a sufficient rate to meet the growth rates. Corporate sustainability, and other non-economic growth factors, are also not modeled.

The Fisher-Pry market growth curves have been developed and refined over time based on empirical adoption data for a wide range of technologies.[13] The model is an imitative model that uses equations developed from historical penetration rates of real products for over two decades. It has been validated in this industry via comparison to historical data for solar photovoltaics, a key focus of this study.

Navigant Consulting has used gathered market data on the adoption of technologies over the past 120 years and fit the data using Fisher-Pry curves. A key parameter when using market penetration curves is the assumed year of introduction. For the market penetration curves used in this study, Navigant assumed that the first-year introduction occurred when the simple payback period was less than 25 years (per the pay-back acceptance curves used, this is the highest pay-back period that has any adoption) or when state or local incentives were first introduced.
When the above payback period, market risk, technology risk, and government regulation factors above are analyzed, our general Fisher-Pry based method gives rise to the following market penetration curves used in this study:

[13] Fisher, J. C. and R. H. Pry, "A Simple Substitution Model of Technological Change", Technological Forecasting and Social Change, 3 (March 1971), 75-88.

Figure 8 **Market Penetration Curves** [14]



Source: Navigant Consulting, November 2008 as taken from Fisher, J.C. and R.H. Pry, A Simple Substitution Model of Technological Change, *Technological Forecasting and Social Change*, Vol 3, Pages 75 – 99, 1971.

The model is designed to analyze the adoption of a single technology entering a market and assumes that the PG market penetration analyzed for each technology is additive because the underlying resources limiting installations (sun, wind, water, high thermal loads) are generally mutually exclusive, and because current levels of market penetration are relatively low (plenty of customers exist for each technology).

1.7 Key Assumptions

The following section details the key technology-specific and base, low and high scenario assumptions.

1.7.1 Technology Assumptions

The following tables summarize cost and performance assumptions for each technology. System size assumptions are provided in APPENDIX B.

1.7.1.1 Reciprocating Engines

A reciprocating engine uses one or more reciprocating pistons to convert pressure into rotating motion. In a combined heat and power (CHP) application, a small CHP source will burn a fuel (natural gas) to produce both electricity and heat. In many applications, the heat is transferred to water, and this hot water is then used to heat a building. In this study we assume the reciprocating engine generates electricity by using natural gas as the fuel.

[14] Realized market penetration is applied to the maximum market penetration (Figure **8**) for each technology, customer payback, and point in time. For example, a residential customer with a five-year payback would have a maximum market penetration of around 35 percent, as indicated by the residential payback acceptance curve (Figure 7). A technology that was introduced 10 years ago will have realized about 20 percent of its maximum market penetration (Figure **8**), having a market penetration of about seven percent of the technical potential.

Navigant sized the system to meet the minimum customer load, assuming the reciprocating engine system would function to meet the customer's base load. Based on system size and product availability, reciprocating engines were assumed a reasonable technology for commercial and industrial customers. Assumptions on system capacity sizes in each state are detailed in APPENDIX B. Table 2 Reciprocating Engine Assumptions provides the cost and performance assumptions used in the analysis and the source for each.

Table 2 Reciprocating Engine Assumptions[15]

PG Resource Costs	Units	2021 Baseline	Sources
Installed Cost – 100kW	$/kW	$2,970	EPA, Catalog of CHP Technologies, March 2015, pg. 2-15
Change in Annual Installed Cost	%	0.4%	ICF International Inc., Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment, pg. 92
Variable O&M	$/MWh	$20	ICF International Inc., Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment, pg. 92
Change in Annual O&M Cost	%	-1.0%	Navigant Assumption
Fuel Cost	$/MWh	PacifiCorp Gas Forecast	PacifiCorp Forecast
PG Performance Assumptions			
Electric Heat Rate (HHV)	Btu/kWh	12,637	EPA, Catalog of CHP Technologies, March 2015, pg. 2-10

1.7.1.2 Micro-turbines

Micro-turbines use natural gas to start a combustor, which drives a turbine. The turbine in turn drives an AC generator and compressor, and the waste heat is exhausted to the user. The device therefore produces electrical power from the generator, and waste heat to the user. In this study we assume the micro-turbine generates electricity by using natural gas as the fuel.

The system was sized to meet the minimum customer load, assuming the reciprocating engine system would function to meet the customer's base load. Based on system size and product availability, reciprocating engines were assumed a reasonable technology for commercial and industrial customers. Assumptions on system capacity sizes in each state are detailed in APPENDIX B. Table 3 Micro-turbines Assumptions provides the cost and performance assumptions used in the analysis and the source for each.

[15] EPA, Catalog of CHP Technologies: www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies.pdf; ICF, Combined Heat and Power Policy Analysis, www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002.pdf

Table 3 Micro-turbines Assumptions[16]

PG Resource Costs	Units	2021 Baseline	Sources
Installed Cost – 30kW	$/kW	$2,685	EPA, Catalog of CHP Technologies, March 2015, pg. 5-7
Change in Annual Installed Cost	%	-0.3%	ICF International Inc., Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment, pg. 97
Variable O&M	$/MWh	$23	ICF International Inc., Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment, pg. 97
Change in Annual O&M Cost	%	-1.0%	Navigant Assumption
Fuel Cost	$/MWh	PacifiCorp Gas Forecast	PacifiCorp Forecast
PG Performance Assumptions			
Electric Heat Rate (HHV)	Btu/kWh	15,535	EPA, Catalog of CHP Technologies, March 2015, pg. 5-6

1.7.1.3 Small Hydro

Small hydro is the development of hydroelectric power on a scale serving a small community or industrial plant. The detailed national small hydro studies conducted by the Department of Energy (DOE) from 2004 to 2013,[17] formed the basis of Navigant's small hydro technical potential estimate. In the Pacific Northwest Basin, which covers WA, OR, ID, and WY, a detailed stream-by-stream analysis was performed in 2013, and DOE provided these data to Navigant directly. For these states, Navigant combined detailed GIS PacifiCorp service territory data with detailed GIS data on each stream / water source. Using this method, Navigant could sum the technical potentials of only those streams located in PacifiCorp's service territory. For the other two states, Utah and California, Navigant relied on an older 2006 national analysis, and multiplied the given state figures by the area served by PacifiCorp within that state. Table 4 provides the cost and performance assumptions used in the analysis and the source for each.

[16] EPA, Catalog of CHP Technologies: www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies.pdf; ICF, Combined Heat and Power Policy Analysis, www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002.pdf

[17] Navigant used the same methodology and sources as in the 2014 study.

Table 4 Small Hydro Assumptions[18]

PG Resource Costs	Units	2021 Baseline	Sources
Installed Cost	$/kW	$4,000	Double average plant costs in "Quantifying the Value of Hydropower in the Electric Grid: Plant Cost Elements." Electric Power Research Institute, November 2011; this accounts for permitting/project costs
Change in Annual Installed Cost	%	0.00%	Mature technology, consistent with other mature technologies in the IRP.
Fixed O&M	$/kW-yr.	$52	Renewable Energy Technologies: Cost Analysis Series. "Hydropower." International Renewable Energy Agency, June 2012.
Change in Annual O&M Cost	%	-1.0%	Navigant Assumption
PG Performance Assumptions			
Capacity Factor	%	50% ±5%	Average capacity factor variance will be reflected in the low and high penetration scenarios.

1.7.1.4 Solar Photovoltaics

Solar photovoltaic (solar) systems convert sunlight to electricity. Navigant applied a 15% discount factor to account DC to AC conversion[19]. System size was then multiplied by the number of customers and the roof access factor. Assumptions on system capacity sizes in each state are detailed in APPENDIX B and access factors remained consistent with the 2014, 2016 and 2018 studies. Table 5 Solar Assumptions provides the cost and performance assumptions used in the analysis and the source for each.

[18] Note: No change from 2014 study.

[19] Navigant used a 15% discount factor to account for DC to AC conversion in PV systems. This value is consistent with industry standards and current system design.

Table 5 Solar Assumptions

PG Resource Costs	Units	2021 Baseline	Sources
Installed Cost – Res	$/kW DC	UT: ~$2,500 Other: $2,750	Navigant Forecast validated by NREL, U.S. Photovoltaic Prices and Cost Breakdowns: Q1 2017 Benchmarks for Residential, Commercial and Utility-Scale Systems
Installed Cost – Non-Res	$/kW DC	All Markets: ~$1,900	
Average Change in Annual Installed Cost (2015-2034)	%	-2.8% (Res) -2.5% (Non-Res)	
Fixed O&M – Res	$/kW-yr.	$25	National Renewable Energy Laboratory, U.S. Residential Photovoltaic (PV) System Prices, Q4 2017 Benchmarks: Cash Purchase, Fair Market Value, and Prepaid Lease Transaction Prices, Oct. 2014; National Renewable Energy Laboratory, Distributed Generation Renewable Energy Estimate of Costs, Accessed February 1, 2016
Fixed O&M – Non-Res	$/kW-yr.	$23	
Change in Annual O&M Cost	%	-1.0%	Navigant Assumption
DC to AC Derate Factor	#	0.85	Industry Standard

As shown in Figure 9 and
Figure 10, the rapid decline in solar costs over the past decade has driven private solar adoption across the country for all customer classes. In the past, these cost declines were primarily due to reduction in the cost of equipment (e.g. panels, inverters and balance of system components) driven by economies of scale and improvements in efficiency. Solar costs are expected to continue to decline over the next decade as system efficiencies continue to increase, although these declines are expected to occur at a slower rate than what occurred in recent years. In the long term, Navigant expects price reductions to decline as the industry matures and efficiency gains become harder to achieve.

Navigant's national solar cost forecast includes a low, base and high forecast. For this project, Navigant developed a PacifiCorp forecast which is the average between the national base and high forecast. Navigant decided to use this forecast for California, Idaho, Oregon, Washington and Wyoming, as all those states currently have small solar markets in PacifiCorp territory, resulting in less competition and economies of scale to drive down local solar costs. For Utah, Navigant used the base cost forecast, as Utah has a larger and more mature private solar market.

Figure 9. Non-Residential Solar System Costs, 2021-2040

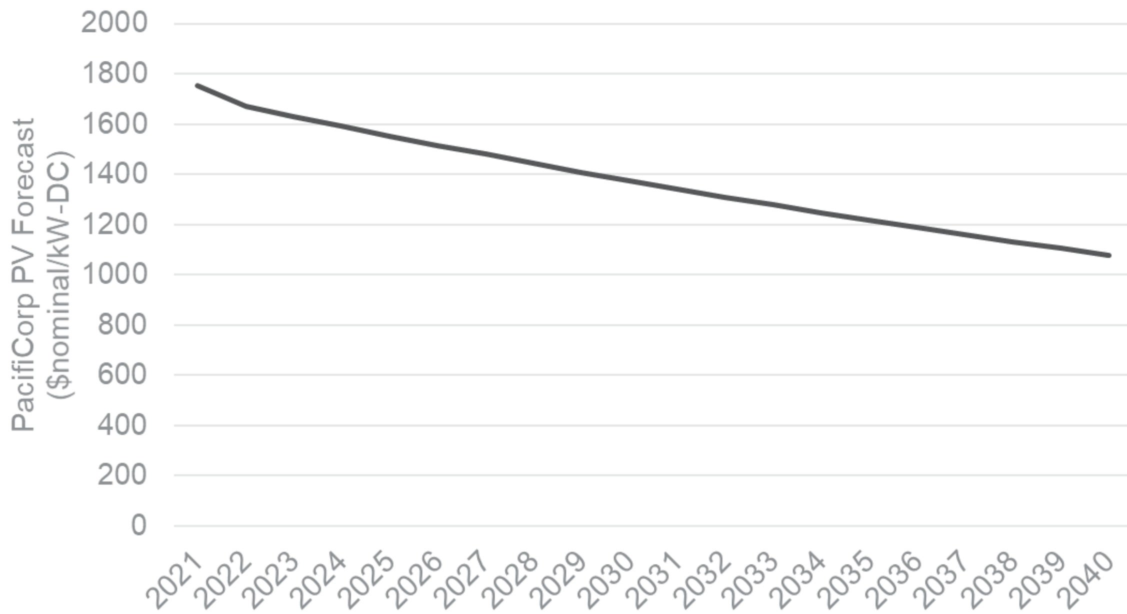
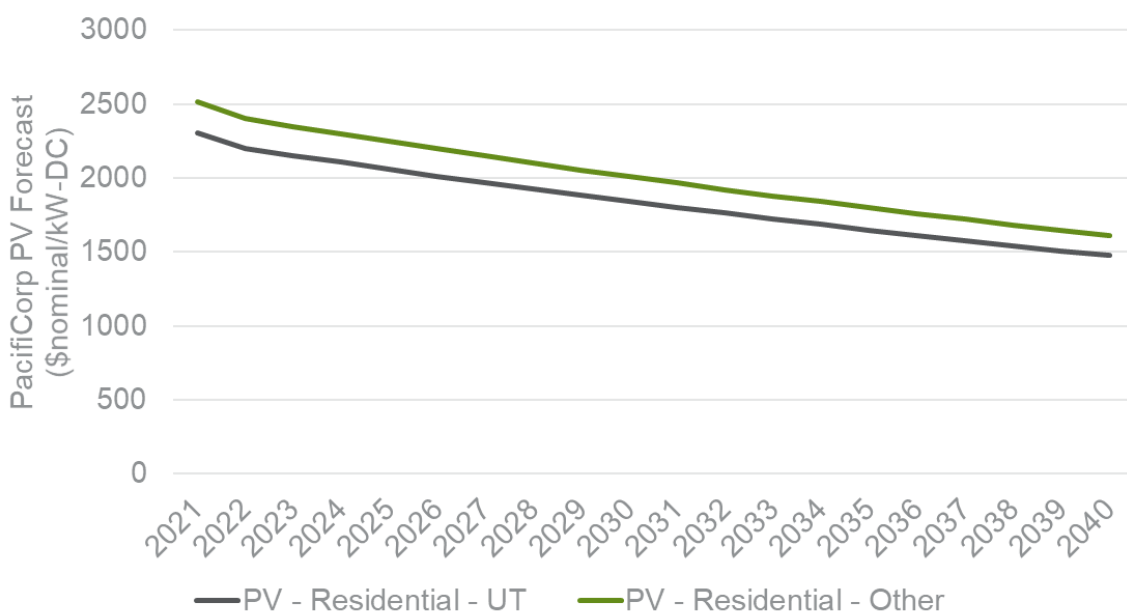


Figure 10 Residential Solar System Costs, 2021-2040



The solar capacity factors (Table 5) were calculated using NREL's System Advisory Model for each state territory.

Table 6 Solar Capacity Factors[20]

Performance Assumptions		
		(kW-DC/kWh AC)
Capacity Factor	UT	16.3%
	WY	16.8%
	WA	14.0%
	CA	16.6%
	ID	16.0%
	OR	12.4%

1.7.1.5 Small Wind

Wind power is the use of air flow through wind turbines to mechanically power generators for electricity. Navigant sized the wind systems at 80% of customer load to reduce the chance that the wind system will produce more than the customer's electric load in a given year. System size was then multiplied by the number of customers and the access factor. The same access factors used in the 2014, 2016 and 2018 studies were used for this study.

The following cost and performance assumptions were used in the analysis.

Table 7 Wind Assumptions

PG Resource Costs	Units	2021 Baseline	Sources
Installed Cost – Res (2.5-10kW)	$/kW	$7,200	Department of Energy, 2014 Distributed Wind Market Report, August 2015
Installed Cost – Com (11-100kW)	$/kW	$6,000	
Change in Annual Installed Cost	%	0.0%	Mature technology, consistent with other mature technologies in the IRP.
Fixed O&M	$/kW-yr.	$40	Department of Energy, 2014 Distributed Wind Market Report, August 2015
Change in Annual O&M Cost	%	-1.0%	Navigant Assumption
PG Performance Assumptions			
Capacity Factor	%	20%	Small scale wind hub heights are lower, with shorter turbine blades, relative to 30% capacity factor large scale turbines.

[20] Navigant used a DC to AC solar PV derate factor of 85%.

1.7.2 Scenario Assumptions

Navigant used the market penetration model to analyze three scenarios, capturing the impact of major changes that could affect market penetration. For the low and high penetration cases, Navigant varied technology costs, system performance, and electricity rate assumptions.

Table 8 Scenario Variable Modifications

Scenarios				
Cases	Technology Costs	Performance	Electricity Rates	Other
Base Case	• See technology and cost section	• As modeled	• Increase at inflation rate, assumed at 2.0%	• Assumes the net metering cap is achieved. Solar PV adoption forecast was adjusted in 2019 and 2020 to reflect this. • Adoption in all other years is based on customer economics.
Low Attractiveness	• PV: Years 1-10: Same as Base Case • Years 11+: Rate of decline is 25% lower than base case • Other: Mature technologies. Same as base case	• PV: Same as Base Case • Other: 5% worse	• Increases at 1.6%, 0.4%/year lower than the Base Case	• Assumes adoptions in based on customer economics for all years.
High Attractiveness	• PV: Years 1-10: Same as Base Case • Years 11+: rate of decline is 50% higher than base case • Other: Mature technologies. Same as base case	• Reciprocating Engines: 0.5% better (mature) • Micro-turbines: 2% better • Hydro: 5% better (reflecting wide performance distribution uncertainty) • PV/Wind: 1% better (relatively mature)	• Increases at 2.4%, 0.4%/year higher than the Base Case	• Assumes the net metering cap is achieved. Solar PV adoption forecast was adjusted in 2019 and 2020 to reflect this. • Adoption in all other years is based on customer economics.

Technology cost reduction is the variable with the largest impact on market penetration over the next 20 years. Average technology performance assumptions are relatively constant across states and sites. Changes in electricity rates are modeled conservatively, reflecting the long-term stability of electricity rates in the United States. Navigant expects short-term volatility for all variables but when averaged over the 20-year IRP period, long-term trends show less variation.

1.7.3 Incentives

Federal and state incentives are a very important PG market penetration driver, as they can reduce a customer's payback period significantly.

1.7.3.1 Federal

The Federal Business Energy Investment Tax Credit (ITC) allows the owner of the system to claim a tax credit for a certain percentage of the installed PG system price.[21] The ITC, originally set to expire in 2016 for residential solar systems and reduce to 10% for commercial solar systems, was extended for solar PV systems in December 2015 through the end of 2021, with step downs occurring in 2020 through 2022. The table below details how the ITC applies to the technologies evaluated in this study, however, this schedule may change in the future.

[21] Business Energy Investment Tax Credit, http://energy.gov/savings/business-energy-investment-tax-credit-itc.

Table 9 Federal Tax Incentives

Technology	2019	2020	2021	2022	2023	>2023
Recip. Engines	**10%**	**10%**	**10%**	**0%**	**0%**	**0%**
Micro Turbines	**10%**	**10%**	**10%**	**0%**	**0%**	**0%**
Small Hydro	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**
PV - Com	**30%**	**26%**	**22%**	**10%**	**10%**	**10%**
PV - Res	**30%**	**26%**	**22%**	**0%**	**0%**	**0%**
Wind - Com	**12%**	**0%**	**0%**	**0%**	**0%**	**0%**
Wind - Res	**30%**	**26%**	**22%**	**22%**	**0%**	**0%**

1.7.3.2 State

State incentives drive the local market and are an important aspect promoting PG market penetration. Currently, all states evaluated have full retail rate net energy metering (NEM) in place for all customer classes considered in this analysis. The study assumes that NEM policy remains constant, although future uncertainty exists surrounding NEM policy. Longer-term uncertainty also exists regarding other state incentives. Utah and Idaho also have local state residential personal tax deduction for solar and wind projects, while Oregon has a performance based incentive for residential and commercial solar PV. Currently, state incentives do not exist in California[22], Washington or Wyoming.

The report continues to incorporate the PG program outlined in Schedule 136[23], as first introduced in the 2018 study. The value of generated energy takes into consideration the reduced compensation for exported energy included in the tariff as well as the capacity cap (see section 1.8.4 for more detail).

The following tables detail the assumptions made regarding local state incentives.

[22] In 2007, California launched the California Solar Initiative, however, incentives no longer remain in most utility territories, http://csi-trigger.com/.

[23] Utah Docket 14-035-114

Table 10 Oregon Incentives

Technology	2019	2020	2021	2022	2023	>2023
Recip. Engines	**0**	**0**	**0**	**0**	**0**	**0**
Micro Turbines	**0**	**0**	**0**	**0**	**0**	**0**
Small Hydro	**0**	**0**	**0**	**0**	**0**	**0**
PV – Com ($/W)	**$0.50-$0.20/W**	**$0.50-$0.20/W**	**$0.50-$0.20/W**	**$0.50-$0.20/W**	**$0.50-$0.20/W**	**$0.50-$0.20/W**
PV – Res ($/W)	**$0.55/W**	**$0.55/W**	**$0.55/W**	**$0.55/W**	**$0.55/W**	**$0.55/W**
Wind – Com ($/kWh)	**0**	**0**	**0**	**0**	**0**	**0**
Wind – Res ($)	**0**	**0**	**0**	**0**	**0**	**0**

* Energy Trust of Oregon Solar Incentive (capped at $1.5M/year for residential).

Table 11 Utah Incentives

Technology	2019	2020	2021	2022	2023	2023	>2024
Recip. Engines (%)	**10**	**10**	**10**	**10**	**10**	**10**	**10**
Micro Turbines (%)	**10**	**10**	**10**	**10**	**10**	**10**	**10**
Small Hydro (%)	**10**	**10**	**10**	**10**	**10**	**10**	**10**
PV – Com (%)	**10**	**10**	**10**	**10**	**10**	**10**	**10**
PV – Res ($)*	**$1,600**	**$1,600**	**$1,600**	**$1,200**	**$800**	**$400**	**$0**
Wind – Com (%)	**10**	**10**	**10**	**10**	**10**	**10**	**10**
Wind – Res ($)*	**$1,200**	**$800**	**$400**	**$0**	**$0**	**$0**	**$0**

*Renewable Energy Systems Tax Credit, Program Cap: Residential cap = $2,000; commercial systems <660kW, no limit

Table 12 Washington Incentives

Technology	2019	2020	2021	2022	2023	>2023
Recip. Engines	**0**	**0**	**0**	**0**	**0**	**0**
Micro Turbines	**0**	**0**	**0**	**0**	**0**	**0**
Small Hydro	**0**	**0**	**0**	**0**	**0**	**0**
PV – Com ($/kWh)*	$0.04 (+$0.04)	$0.02 (+$0.03)	$0.02 (+$0.02)	0	0	0
PV – Res ($/kWh)*	$0.14 (+$0.04)	$0.12 (+$0.03)	$0.10 (+$0.02)	0	0	0
Wind – Com ($/kWh)*	$0.04 (+$0.04)	$0.02 (+$0.03)	$0.02 (+$0.02)	0	0	0
Wind – Res ($/kWh)*	$0.14 (+$0.04)	$0.12 (+$0.03)	$0.10 (+$0.02)	0	0	0

* Feed-in Tariff: $/kWh for all kWh generated through mid-2020; annually capped at $5,000/year, http://programs.dsireusa.org/system/program/detail/5698

Table 13 Idaho Incentives

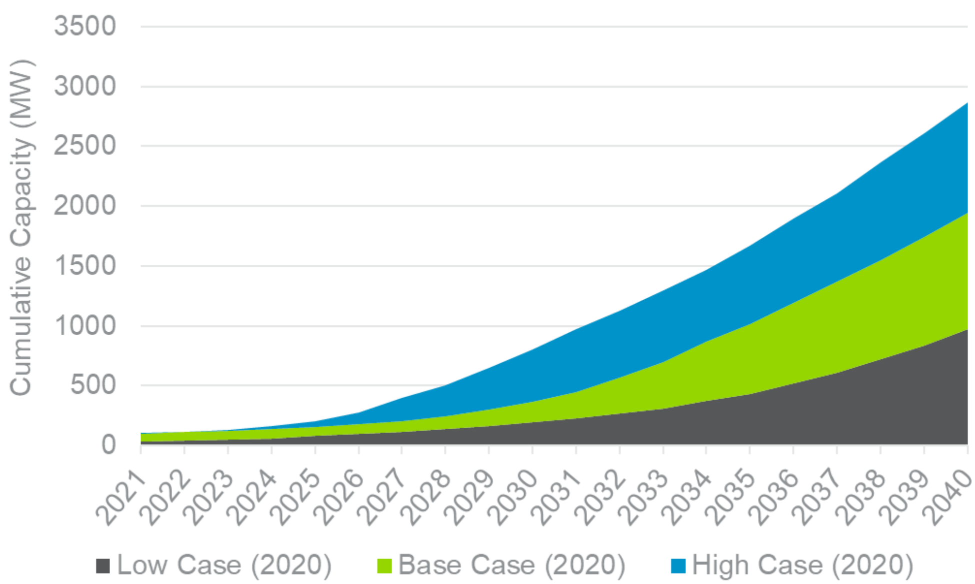
Technology	2019	2020	2021	2022	2023	>2023
Recip. Engines	**0**	**0**	**0**	**0**	**0**	**0**
Micro Turbines	**0**	**0**	**0**	**0**	**0**	**0**
Small Hydro	**0**	**0**	**0**	**0**	**0**	**0**
PV - Com	**0**	**0**	**0**	**0**	**0**	**0**
PV – Res (%)*	**40,20,20,20**	**40,20,20,20**	**40,20,20,20**	**40,20,20,20**	**40,20,20,20**	**40,20,20,20**
Wind – Com	**0**	**0**	**0**	**0**	**0**	**0**
Wind – Res (%)*	**40,20,20,20**	**40,20,20,20**	**40,20,20,20**	**40,20,20,20**	**40,20,20,20**	**40,20,20,20**

* Residential Alternative Energy Income Tax Deduction: 40% in the first year and 20% for the next three years, http://programs.dsireusa.org/system/program/detail/137.

RESULTS

Navigant estimates approximately 1.9 GW of PG capacity will be installed in PacifiCorp's territory from 2021-2040 in the base case scenario. As shown in Figure 11, the low and high scenarios project a cumulative installed capacity of 1.0 GW and 2.9 GW by 2040, respectively. The main drivers between the different scenarios include variation in technology costs, system performance, and electricity rate assumptions.

Figure 11. Cumulative Market Penetration Results (MW AC), 2021 – 2040



1.8 PacifiCorp Territories

The following sections report the results by state, providing high, base and low scenario installation projections. Results for each scenario are also broken out by technology. The solar sector exhibits the highest adoption across all states. Generally non-residential solar adoption is less sensitive to high and low scenario adjustments when compared to the residential sector. This is because the residential customer payback is more sensitive to scenario changes (e.g. technology costs, performance, electricity rates) when compared to non-residential sectors.

1.8.1 California

PacifiCorp's customers in northern California are projected to install about 31 MW of capacity over the next two decades in the base case, averaging about 1.5 MW, annually. California does not currently have any state incentives promoting the installation of PG and the ratcheting down of the Federal ITC from 2020 to 2022 has a negative impact on annual capacity installations after 2020. The main driver of PG in California is its high electricity rates relative to other states. However, cumulative residential PG adoption in California decreased significantly compared to the 2018 study due to a 47% decline in the residential offset rates used in the 2020 study (changes to the net billing framework were incorporated in the offset rates). Over time, the increase in PG installation capacity is driven by escalating electricity rates (benchmarked to inflation) and declining technology costs. Both residential and non-residential solar installations are responsible for the majority of PG growth over the horizon of this study.

While the low and high scenarios follow similar market trends as the base case, the cumulative installations over the planning horizon differ significantly, as shown in Figure 12. The 31 MW from the base case decreases by 54% to 14 MW in the low case and increases by 71% to 53 MW in the high case. Compared to the 2018 study, California is expected to have less residential solar PV adoption in the long-run due a notable reduction in offset rates in California.

Figure 12. Cumulative Capacity Installations by Scenario (MW AC), California

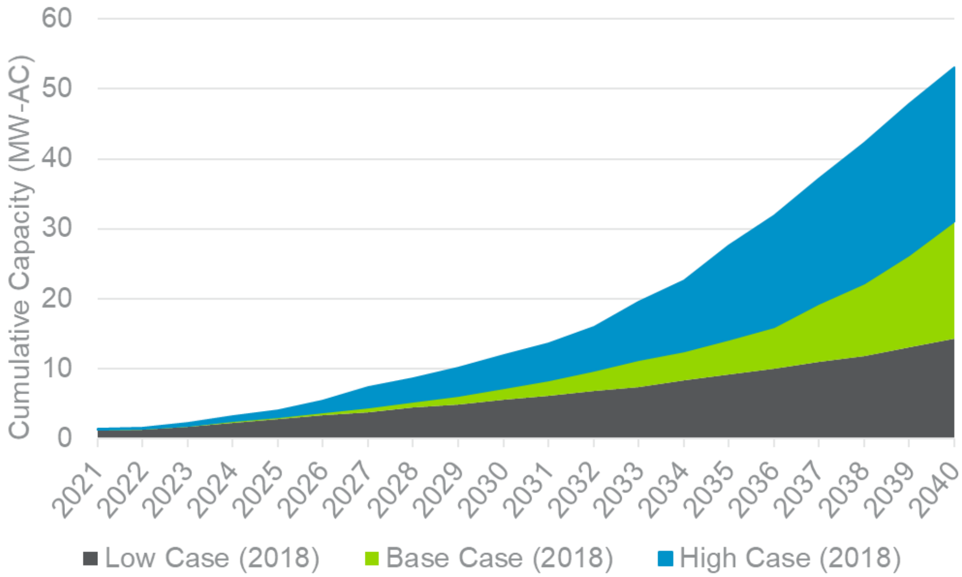


Figure 13. Cumulative Capacity Installations by Technology (MW AC), California Base Case

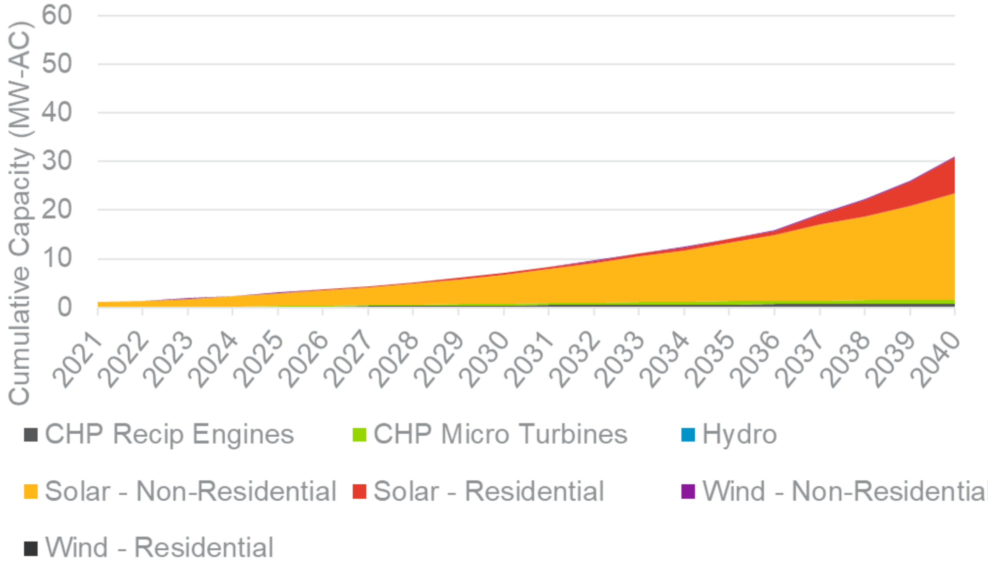


Figure 14. Cumulative Capacity Installations by Technology (MW AC), California High Case

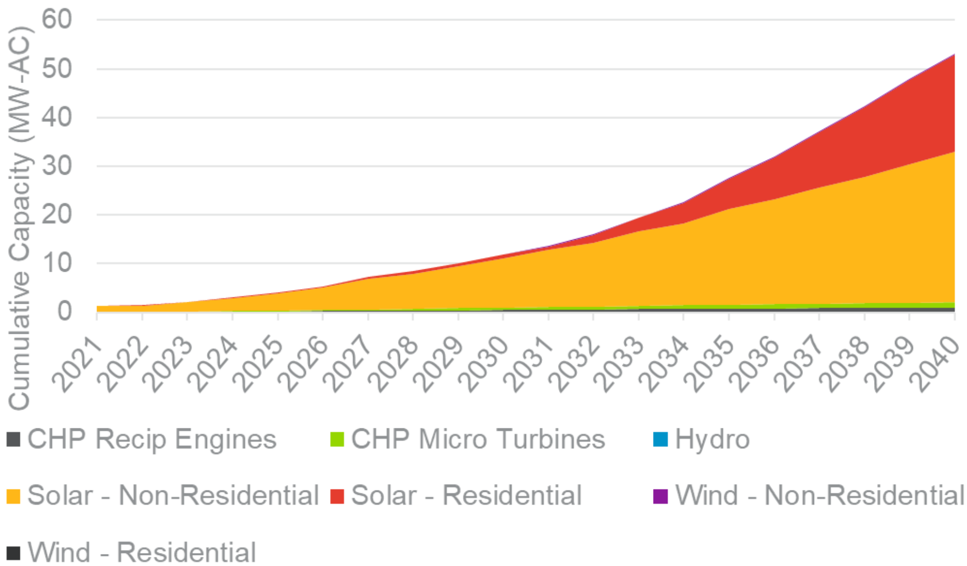
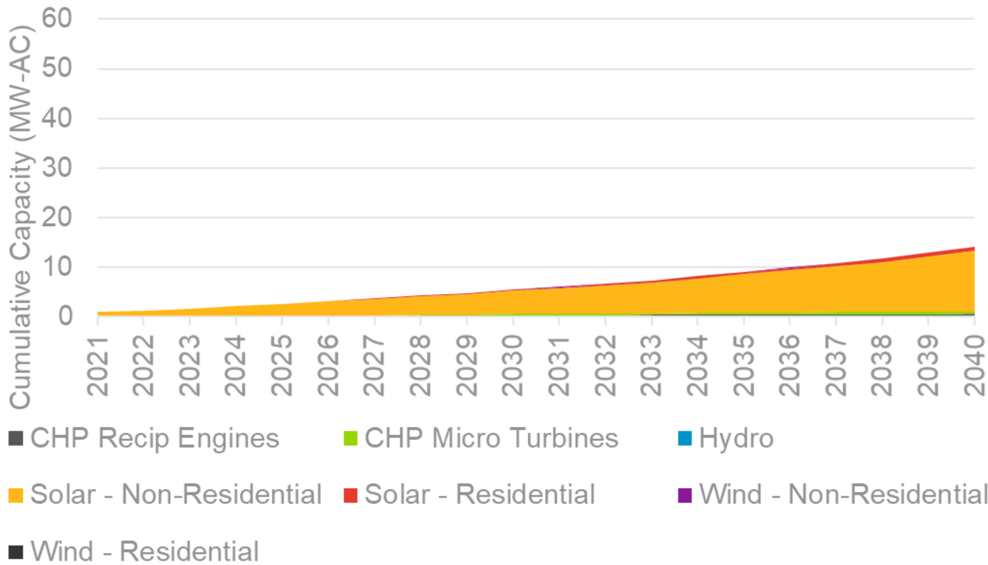


Figure 15. Cumulative Capacity Installations by Technology (MW AC), California Low Case



1.8.2 Idaho

PacifiCorp's Idaho customers are projected to install about 127 MW of capacity over the next two decades in the base case, averaging about 6 MW annually. Idaho currently has a Residential Alternative Energy Income Tax Deduction for residential solar and wind installations[24], although this incentive seems to have had minimal impact on the market, as non-residential solar installations are responsible for the majority of PG growth in the early years due to a combination of technical potential and escalating electric rates. The ratcheting down of the Federal ITC from 2020 to 2022 has a negative impact on annual capacity installations in the short term and overtime the increase in PG installation capacity is driven by escalating electricity rates (benchmarked to inflation) and declining technology costs. A 10% increase in customer count contributed a positive impact on the cumulative installations over the planning horizon.

While the low and high scenarios follow similar market trends as the base case, the cumulative installations over the planning horizon differ significantly, as shown in Figure 16. The 127 MW from the base case decreases by 37% to 80 MW in the low case and increases by 32% to 168 MW in the high case.

[24] Residential Alternative Energy Income Tax Deduction: 40% in the first year and 20% for the next three years, http://programs.dsireusa.org/system/program/detail/137.

Figure 16. Cumulative Capacity Installations by Scenario (MW AC), Idaho

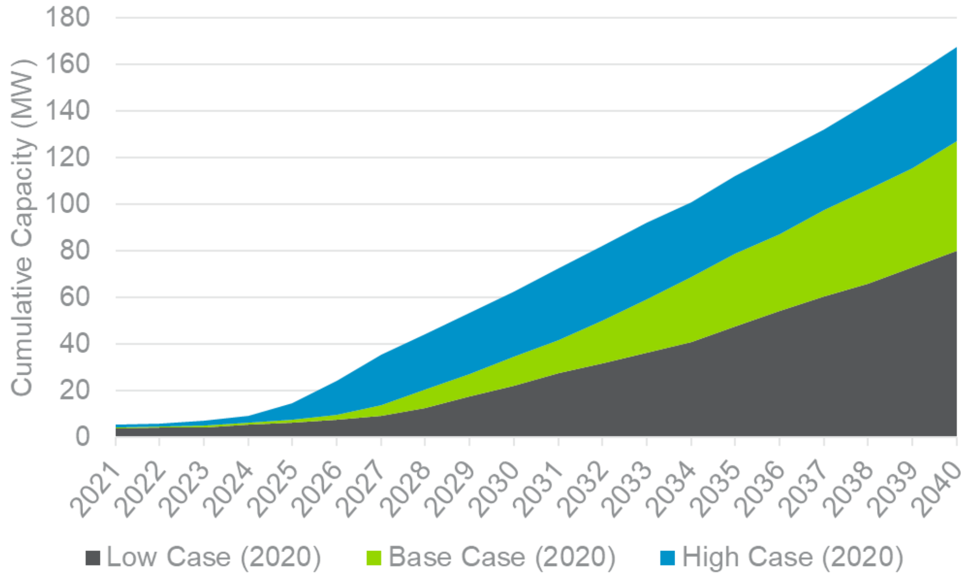


Figure 17. Cumulative Capacity Installations by Technology (MW AC), Idaho Base Case

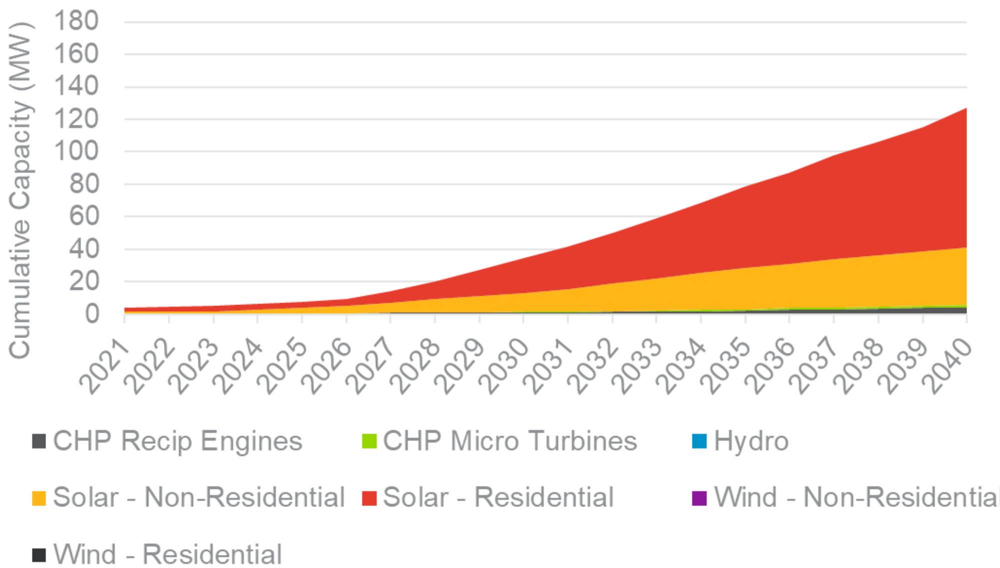


Figure 18. Cumulative Capacity Installations by Technology (MW AC), Idaho High Case

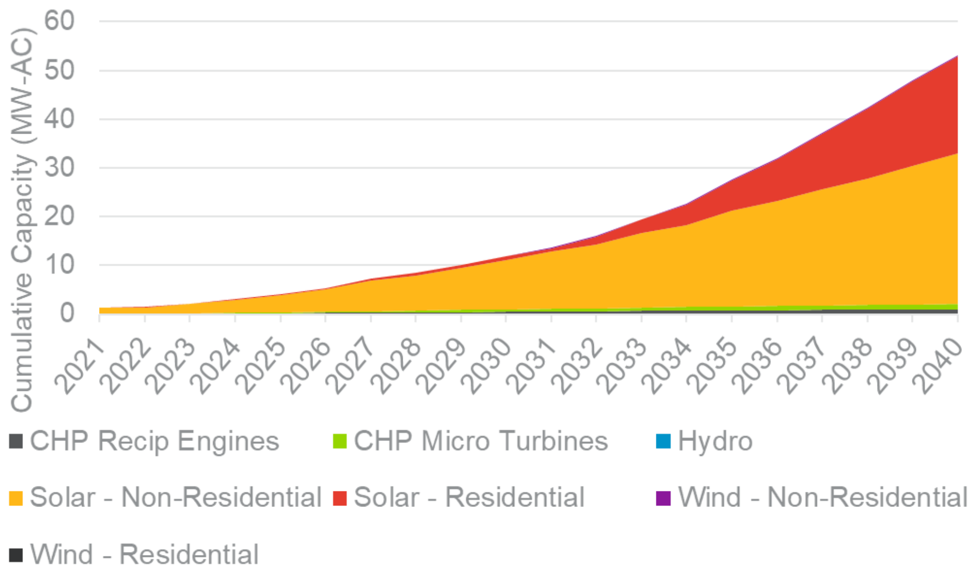
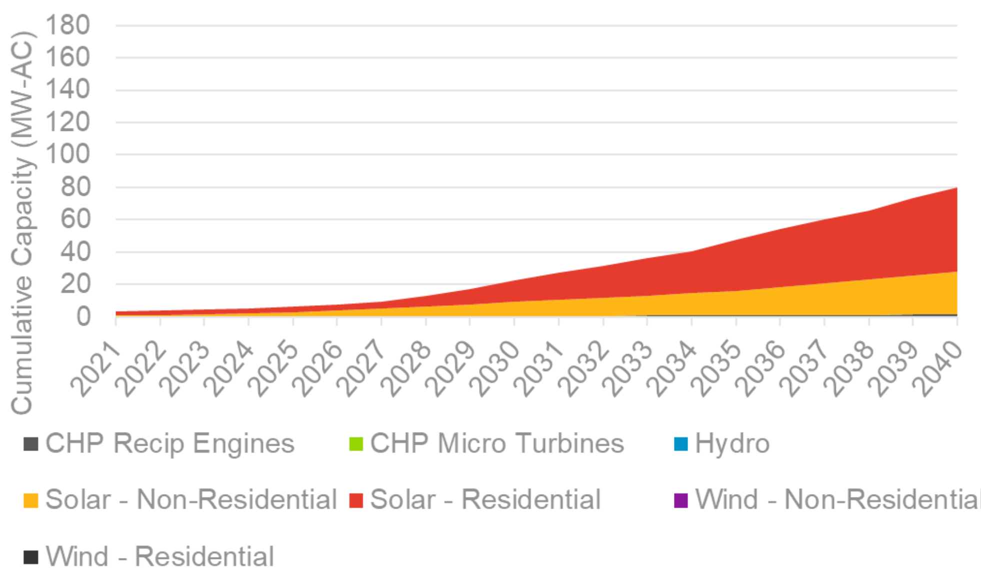


Figure 19. Cumulative Capacity Installations by Technology (MW AC), Idaho Low Case



1.8.3 Oregon

PacifiCorp's Oregon customers are projected to install about 706 MW of PG capacity over the next two decades in the base case, averaging about 34 MW annually. Solar is responsible for the majority of PG growth over the horizon of this study, with small growth from CHP reciprocating engines and non-residential wind. The stronger solar resource in Oregon relative to most of other states in PacifiCorp's territory and the Energy Trust of Oregon's Solar Incentive drive solar market adoption. The ratcheting down of the Federal ITC from 2020 to 2022 results in a relatively flat market in the short term but overtime the increase in solar capacity installation is driven by escalating electricity rates (benchmarked to inflation) and declining technology costs. A 7.5% increase in customer count contributed a positive impact on the cumulative installations over the planning horizon.

While the low and high scenarios follow similar market trends as the base case, the cumulative installations over the planning horizon differ significantly, as shown in Figure 20. The 706 MW from the base case decreases by 49% to 360 MW in the low case and increases by 45% to 1,026 MW in the high case.

Figure 20. Cumulative Capacity Installations by Scenario (MW AC), Oregon

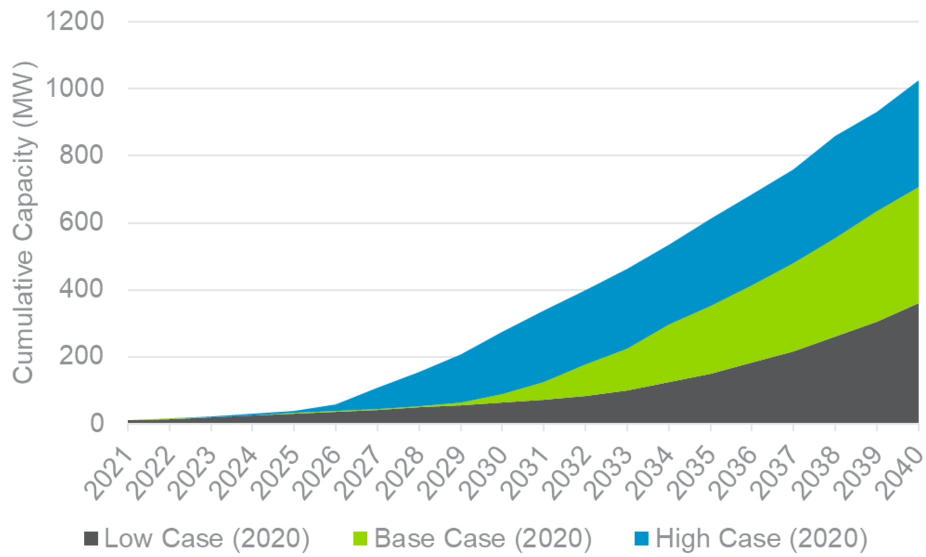


Figure 21. Cumulative Capacity Installations by Technology (MW AC), Oregon Base Case

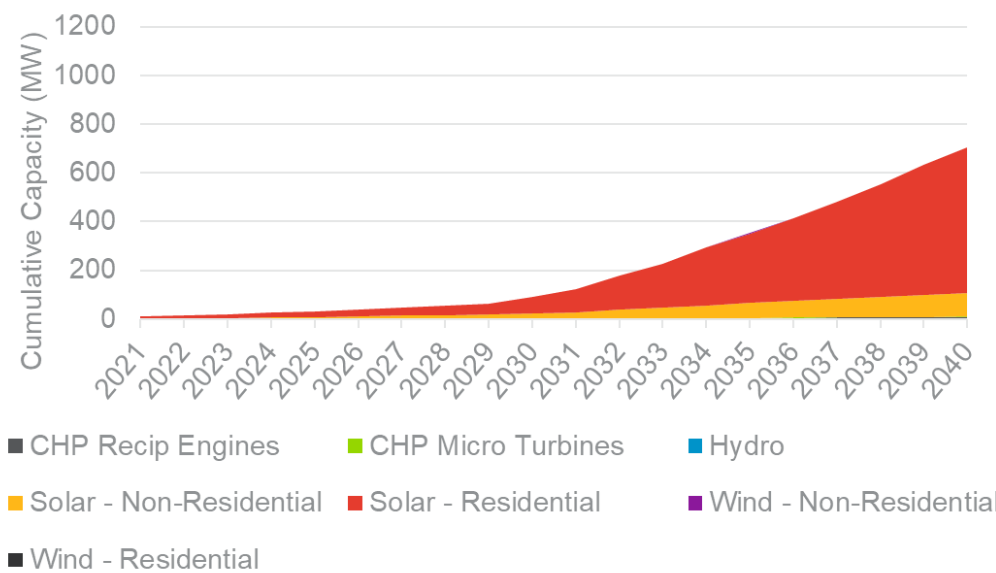


Figure 22. Cumulative Capacity Installations by Technology (MW AC), Oregon High Case

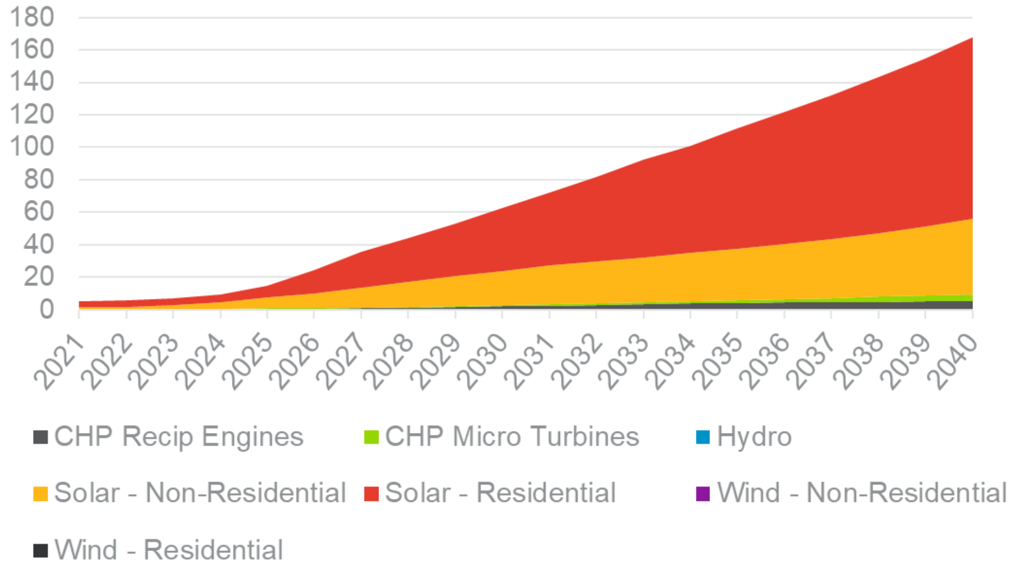
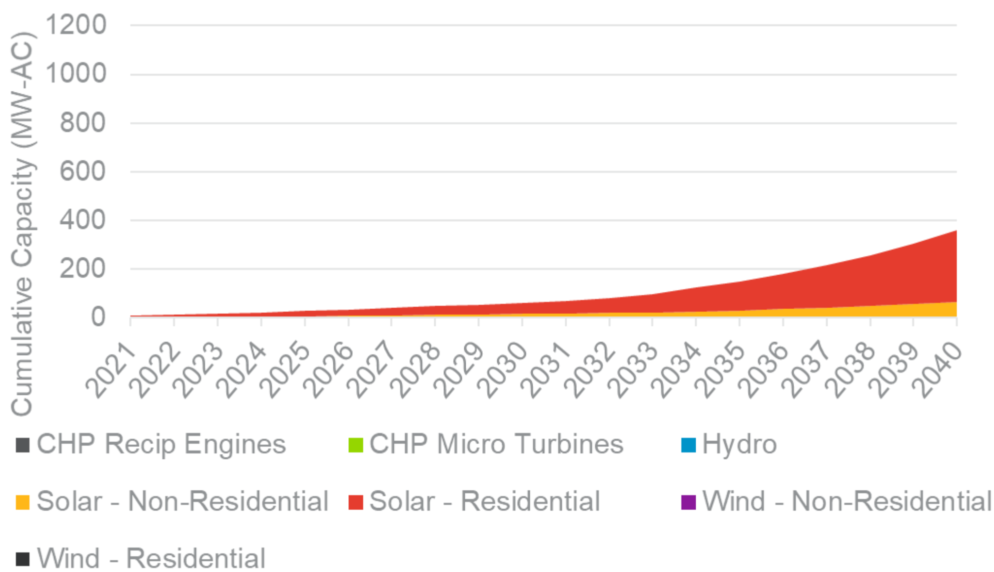


Figure 23 Cumulative Capacity Installations by Technology (MW AC), Oregon Low Case



1.8.4 Utah

PacifiCorp's Utah customers are projected to install about 885 MW of PG capacity over the next two decades in the base case, averaging 42 MW annually. Solar is responsible for most PG installations over the horizon of this study, with reciprocating engines being installed in small numbers in future years. Utah has the strongest solar resource in PacifiCorp's territory and system costs are lower than in other states due to Utah's larger and more mature market. Compared to the 2018 study, commercial offset rates in Utah increased nearly 40%, driving additional PG adoption in the commercial sector.

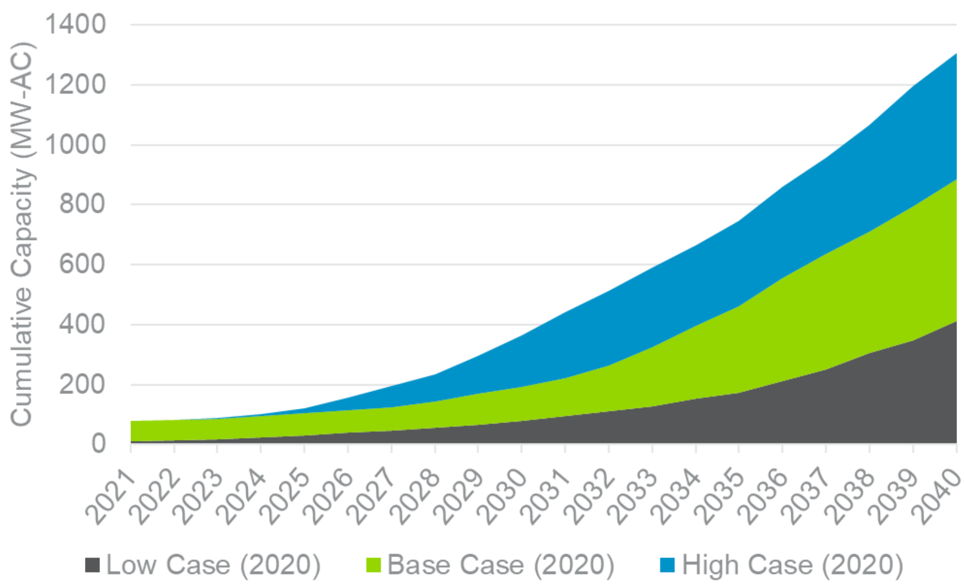
Additionally, a 12% increase in customer count contributed a positive impact on the cumulative installations over the planning horizon.

The projection in the early years is dominated by residential customers adopting solar. The state Renewable Energy Systems Tax Credit applies to all technologies evaluated and has an impact on solar adoption. Solar adoption declines dramatically in 2020 as the ITC ratchets down. In 2025 projected capacity installation increases as solar prices continue to decline and utility rates escalate (benchmarked to inflation).

The report continues to incorporate the regulatory modifications Schedule 13625 brought to the PG program in Utah, as first introduced in the 2018 study. The value of generated energy takes into consideration the recently approved compensation for exported energy included in the tariff. Additionally, the forecast installations for year 2021 in the base and high case reflects the capacity cap included within Schedule 136, while low case reflects the assumptions as outlined in Table 11.

While the low and high scenarios follow similar market trends as the base case, the cumulative installations over the planning horizon differ significantly, as shown in Figure 24. The 885 MW from the base case decreases by 53% to 413 MW in the low case and increases by 48% to 1,308 MW in the high case.

Figure 24. Cumulative Capacity Installations by Scenario (MW AC), Utah



[25] Utah Docket 14-035-114

Figure 25. Cumulative Capacity Installations by Technology (MW AC), Utah Base Case

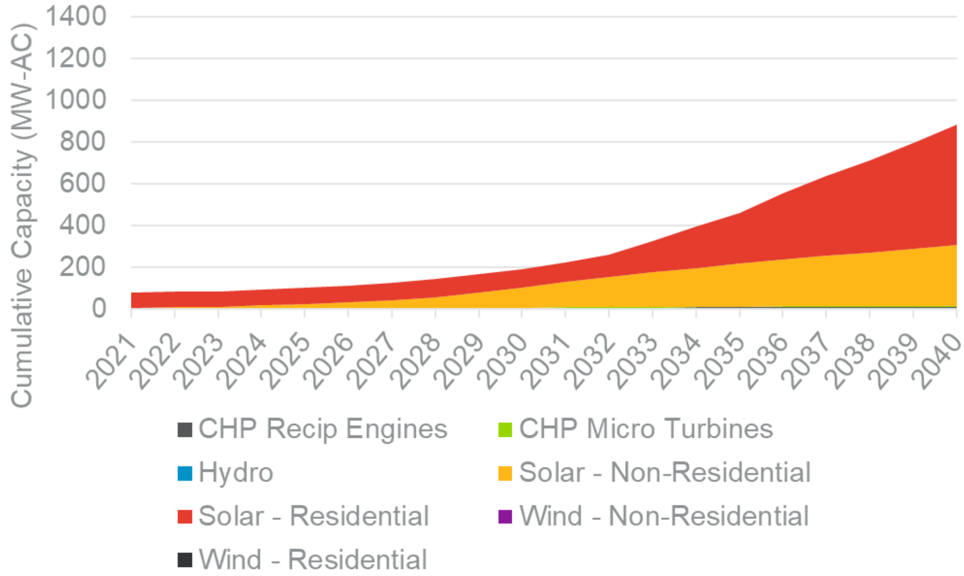


Figure 26. Cumulative Capacity Installations by Technology (MW AC), Utah High Case

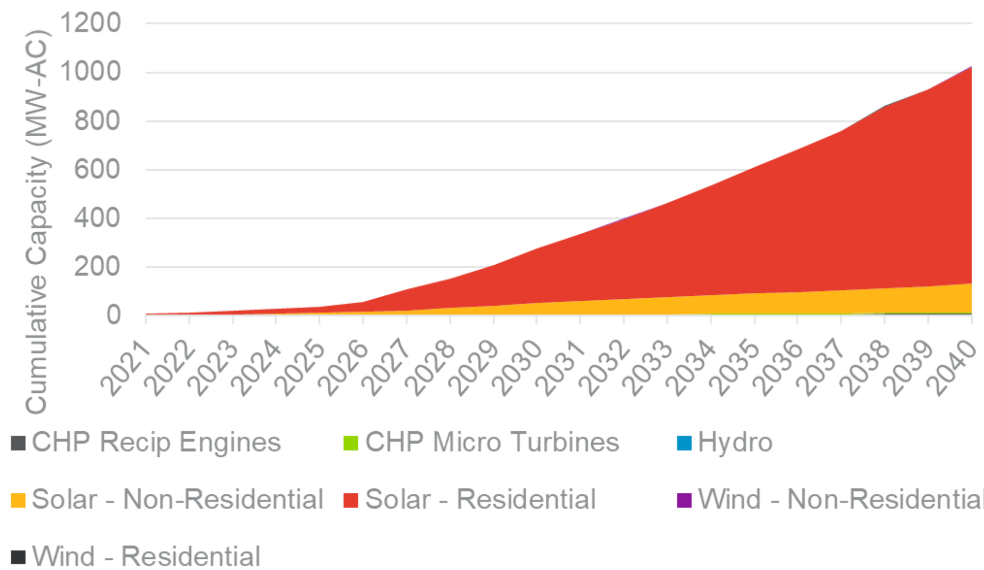
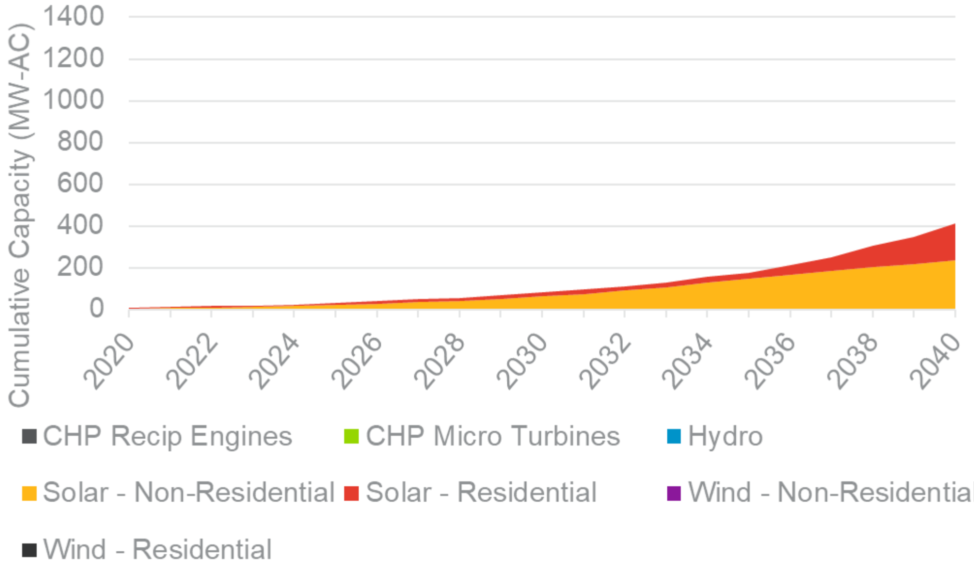


Figure 27. Cumulative Capacity Installations by Technology (MW AC), Utah Low Case



1.8.5 Washington

PacifiCorp's Washington customers are expected to install about 80 MW of PG capacity over the next two decades in the base case, averaging 4 MW annually. Solar is responsible for most PG installations over the horizon of this study, with reciprocating engines being installed in small numbers in future years. Washington does not have a very strong solar resource, yet the lucrative Feed-In-Tariff in Washington, which extends through 2021, should drive the solar market in the near term. The solar market is driven by non-residential solar installations, most likely due to the lower cost of installing larger systems. Solar adoption declines dramatically in 2020 as the ITC ratchets down. In 2025, installation capacity increases as solar prices continue to decline and utility rates escalate (benchmarked to inflation). A 5.5% increase in customer count contributed a positive impact on the cumulative installations over the forecast horizon.

While the low and high scenarios follow similar market trends as the base case, the cumulative installations over the planning horizon differ significantly, as shown in Figure 28. The 80 MW from the base case decreases by 53% to 38 MW in the low case and increases by 72% to 139 MW in the high case.

Figure 28. Cumulative Capacity Installations by Scenario (MW AC), Washington

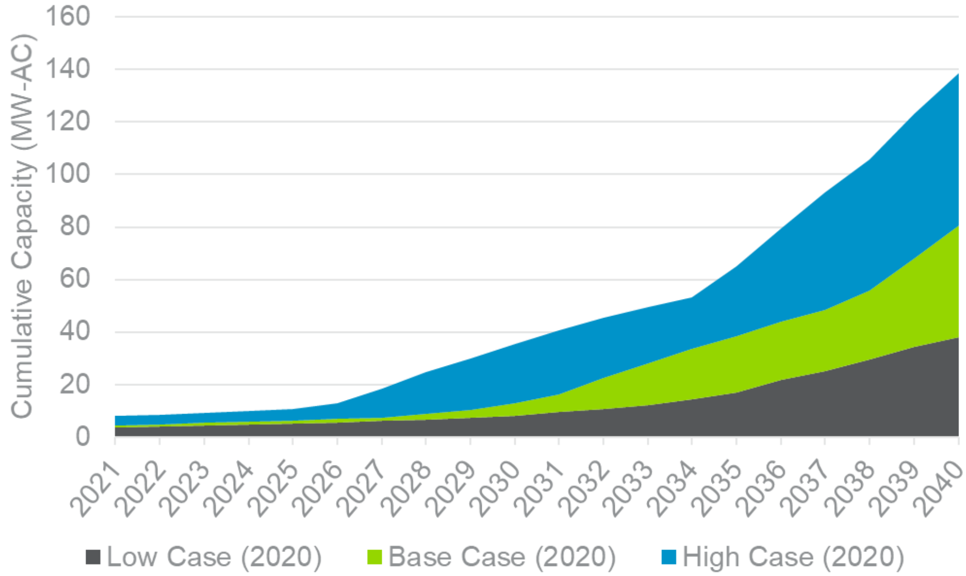


Figure 29. Cumulative Capacity Installations by Technology (MW AC), Washington Base Case

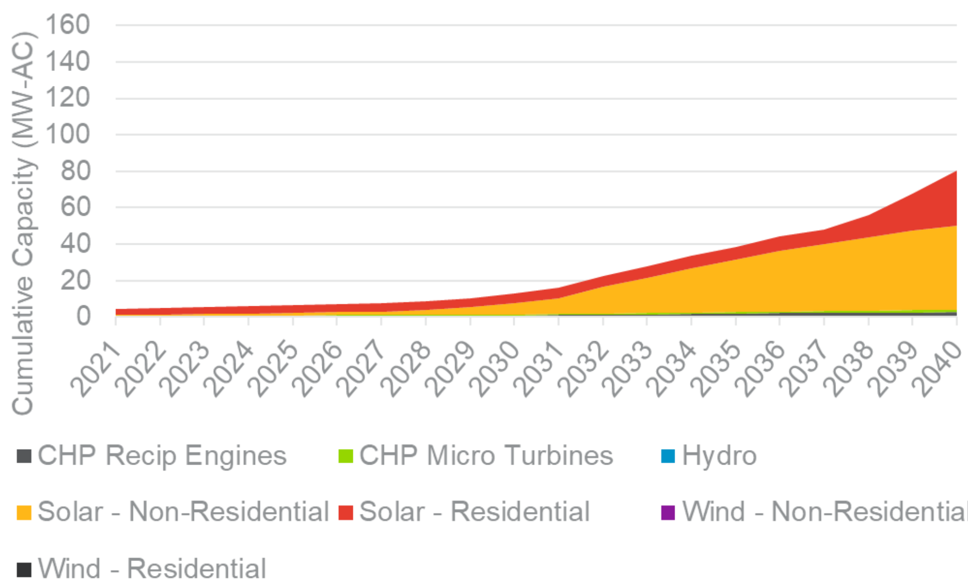


Figure 30. Cumulative Capacity Installations by Technology (MW AC), Washington High Case

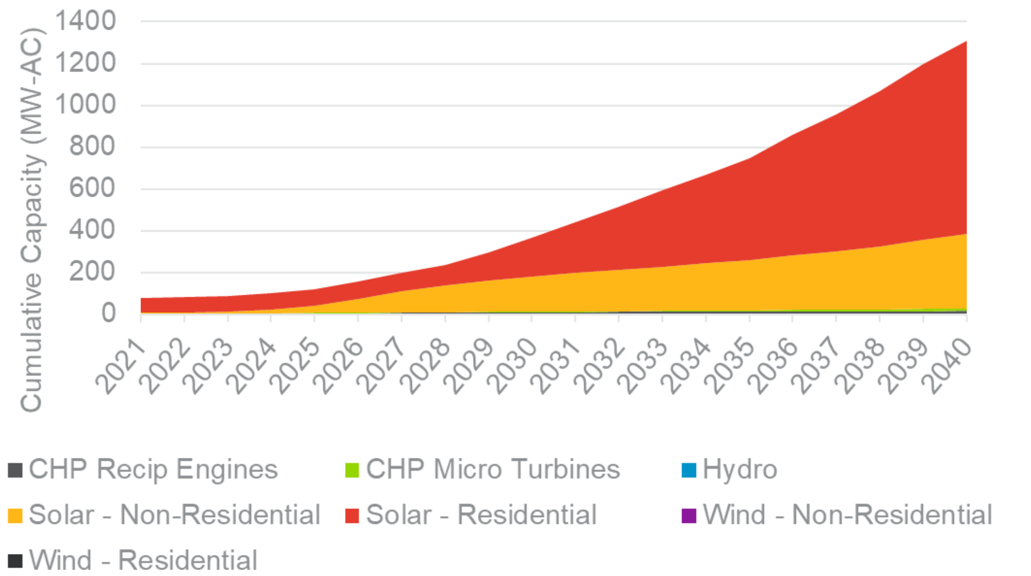
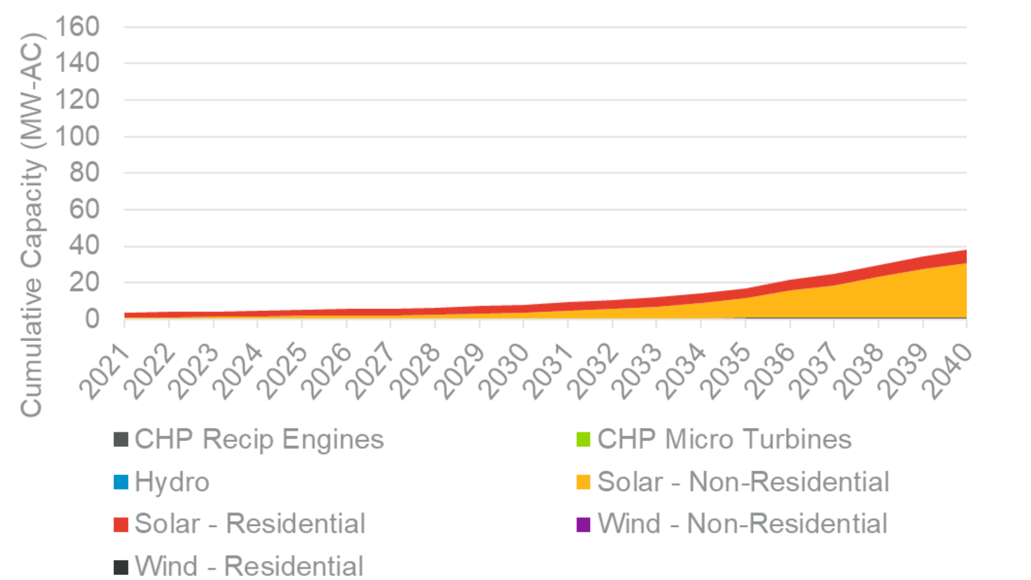


Figure 31. Cumulative Capacity Installations by Technology (MW AC), Washington Low Case



1.8.6 Wyoming

PacifiCorp's Wyoming customers are projected to install about 114 MW of capacity over the next two decades in the base case, averaging about 5.4 MW annually. Solar is responsible for most PG installations over the horizon of this study, with reciprocating engines, and small wind being installed in small numbers in future years. Wyoming does not have any state incentives promoting the installation of PG. Similar to other states, the ratcheting down of the Federal ITC from 2020 to 2022 has a negative impact on annual capacity installations, but in 2023 the market begins to grow at a faster pace, driven by escalating electricity rates (benchmarked to inflation) and declining technology costs. Both residential and non-residential solar installations are responsible for the majority of PG growth over the horizon of this study.

While the low and high scenarios follow similar market trends as the base case, the cumulative installations over the planning horizon differ significantly, as shown in Figure 32. The 114 MW from the base case decreases by 43% to 65 MW in the low case and increases by 50% to 171 MW in the high case.

Figure 32. Cumulative Capacity Installations by Scenario, Wyoming

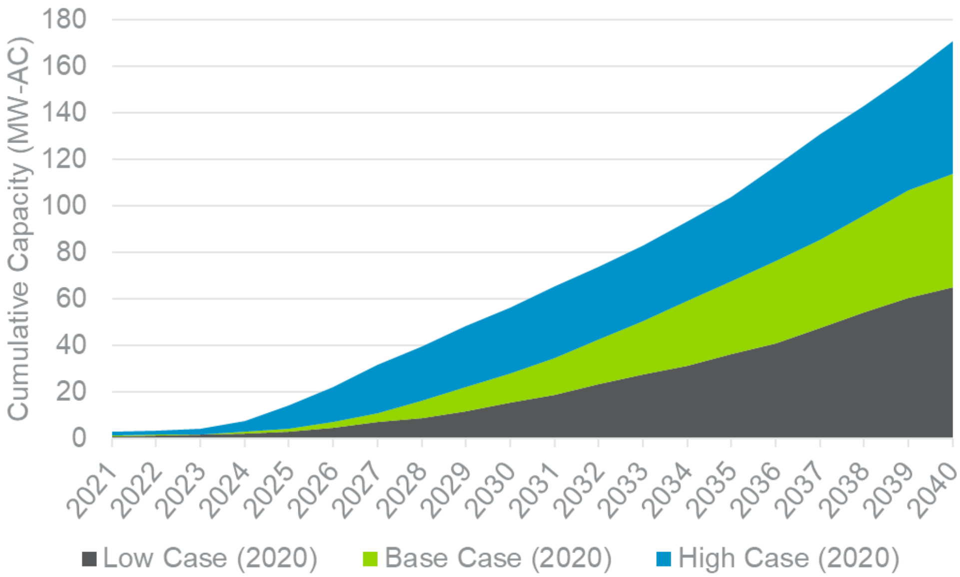


Figure 33. Cumulative Capacity Installations by Technology (MW AC), Wyoming Base Case

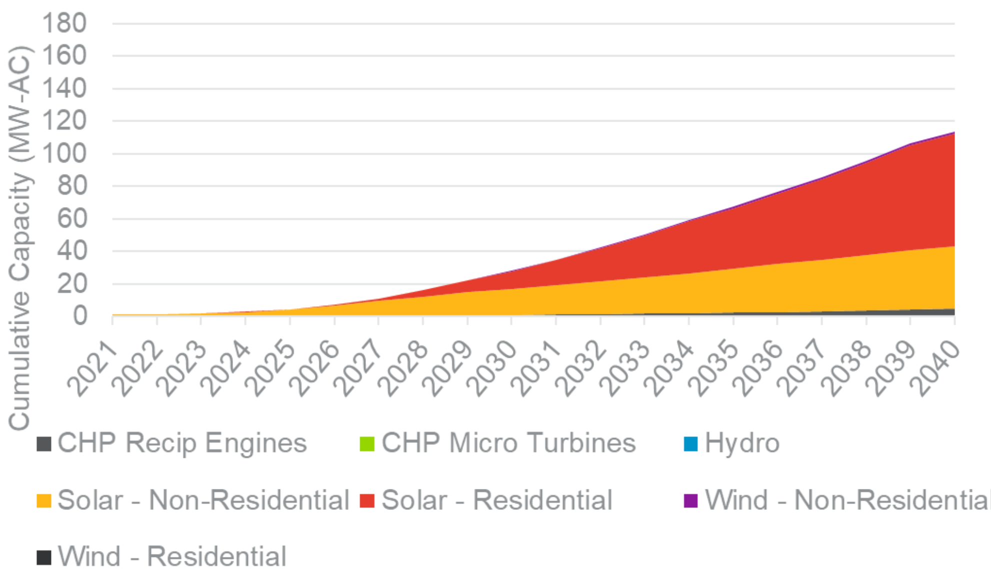


Figure 34. Cumulative Capacity Installations by Technology, Wyoming High Case

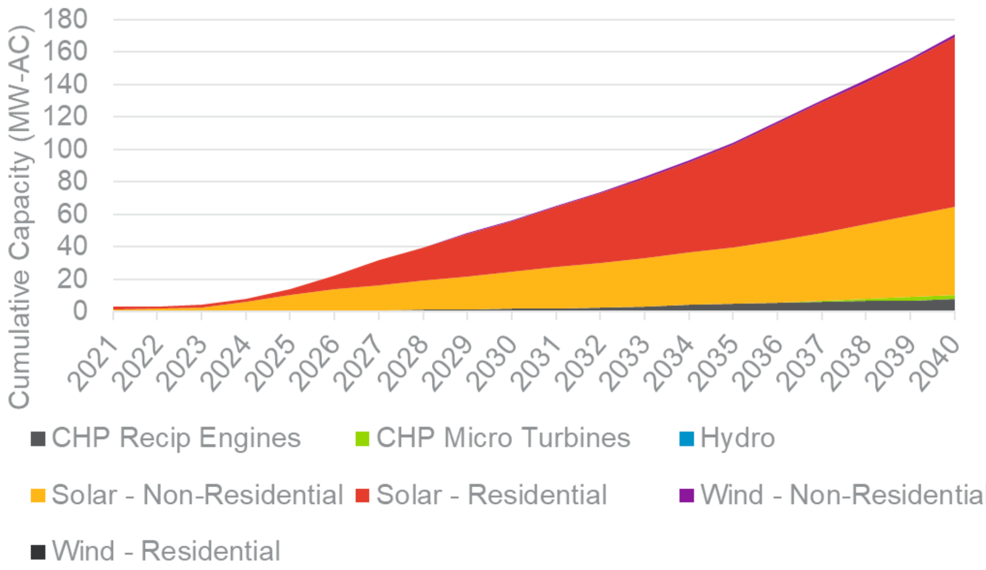
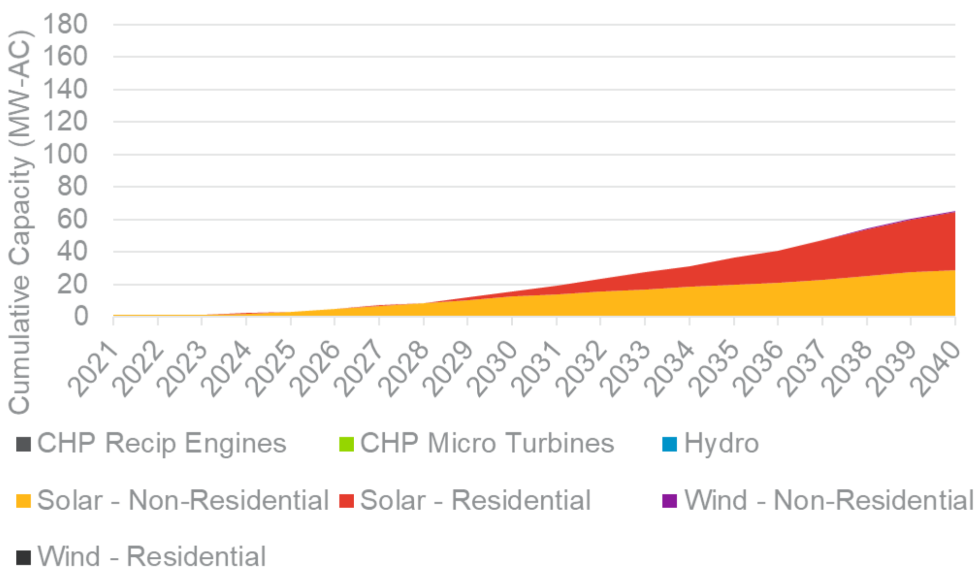


Figure 35. Cumulative Capacity Installations by Technology (MW AC), Wyoming Low Case



APPENDIX A. CUSTOMER DATA

Table 14 California

Rate Class	# Customers	2020 MWh Sales	Avg. Rates ($/kWh)
Residential	36,081	381,625	0.088
Commercial	7,360	244,248	0.149
Industrial	111	58,758	0.136
Irrigation	1,830	87,802	0.136

Table 15 Idaho

Rate Class	# Customers	2020 MWh Sales	Avg. Rates ($/kWh)
Residential	67,442	735,925	0.131
Commercial	9,277	513,544	0.085
Industrial	592	11,828,179	0.068
Irrigation	5,084	640,198	0.068

Table 16 Oregon

Rate Class	# Customers	2020 MWh Sales	Avg. Rates ($/kWh)
Residential	519,457	5,676,002	0.104
Commercial	69,373	5,858,774	0.089
Industrial	1,525	1,693,832	0.076
Irrigation	7,637	333,940	0.076

Table 17 Utah

Rate Class	# Customers	2020 MWh Sales	Avg. Rates ($/kWh)
Residential	852,304	7,267,347	0.103
Commercial	90,773	9,335,173	0.081
Industrial	4,768	8,045,765	0.059
Irrigation	3,438	231,548	0.059

Table 18 Washington

Rate Class	# Customers	2020 MWh Sales	Avg. Rates ($/kWh)
Residential	110,627	1,591,155	0.101
Commercial	16,446	1,596,374	0.079
Industrial	477	805,295	0.069
Irrigation	5,020	159,179	0.069

Table 19 Wyoming

Rate Class	# Customers	2020 MWh Sales	Avg. Rates ($/kWh)
Residential	116,338	959,613	0.116
Commercial	23,057	1,401,596	0.085
Industrial	1,991	6,940,902	0.062
Irrigation	792	24,978	0.062

APPENDIX B. SYSTEM CAPACITY ASSUMPTIONS

Table 20 Access Factors (%)

Technology	CA	ID	OR	UT	WA	WY
Recip. Engines	N/A	N/A	N/A	N/A	N/A	N/A
Micro Turbines	N/A	N/A	N/A	N/A	N/A	N/A
Small Hydro	N/A	N/A	N/A	N/A	N/A	N/A
PV - Com	42%	42%	42%	42%	42%	42%
PV - Res	35%	35%	35%	35%	35%	35%
Wind - Com	5%	5%	8%	16%	8%	51%
Wind - Res	5%	5%	8%	16%	8%	51%

Table 21 California (kW AC)

Technology	Commercial	Irrigation	Residential	Industrial
Recip. Engines	2	N/A	N/A	28
Micro Turbines	2	N/A	N/A	28
Small Hydro	500	N/A	N/A	500
PV - Com	18	29	N/A	212
PV - Res	N/A	N/A	6	N/A
Wind - Com	10	16	N/A	113
Wind - Res	N/A	N/A	3	N/A

Table 22 Idaho (kW AC)

Technology	Commercial	Irrigation	Residential	Industrial
Recip. Engines	4	N/A	N/A	185
Micro Turbines	4	N/A	N/A	185
Small Hydro	500	N/A	N/A	500
PV - Com	31	68	N/A	250
PV - Res	N/A	N/A	6	N/A
Wind - Com	29	62	N/A	1515
Wind - Res	N/A	N/A	6	N/A

Table 23 Oregon (kW AC)

Technology	Commercial	Irrigation	Residential	Industrial
Recip. Engines	6	N/A	N/A	110
Micro Turbines	6	N/A	N/A	110
Small Hydro	500	N/A	N/A	500
PV - Com	25	32	N/A	100
PV - Res	N/A	N/A	6	N/A
Wind - Com	30	17	N/A	584
Wind - Res	N/A	N/A	4	N/A

Table 24 Utah (kW AC)

Technology	Commercial	Irrigation	Residential	Industrial
Recip. Engines	7	N/A	N/A	150
Micro Turbines	7	N/A	N/A	150
Small Hydro	500	N/A	N/A	500
PV - Com	58	39	N/A	130
PV - Res	N/A	N/A	5	N/A
Wind - Com	56	N/A	N/A	938
Wind - Res	N/A	N/A	5	N/A

Table 25 Washington (kW AC)

Technology	Commercial	Irrigation	Residential	Industrial
Recip. Engines	6	N/A	N/A	88
Micro Turbines	6	N/A	N/A	88
Small Hydro	500	N/A	N/A	500
PV - Com	65	21	N/A	250
PV - Res	N/A	N/A	10	N/A
Wind - Com	41	13	N/A	655
Wind - Res	N/A	N/A	6	N/A

Table 26 Wyoming (kW AC)

Technology	Commercial	Irrigation	Residential	Industrial
Recip. Engines	150	N/A	N/A	150
Micro Turbines	150	N/A	N/A	150
Small Hydro	500	N/A	N/A	500
PV - Com	25	17	N/A	150
PV - Res	N/A	N/A	5	N/A
Wind - Com	23	11	N/A	1192
Wind - Res	N/A	N/A	3	N/A

APPENDIX C. WASHINGTON HIGH-EFFICIENCY COGENERATION LEVELIZED COSTS

Section 480.109.100 of the Washington Administrative Code[26] 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. To supplement the analysis in the main body of this report addressing reliability and feasibility, this appendix, analyzes the levelized cost of energy (LCOE) of these resources, for use in cost-effectiveness analysis.

Key assumptions for the analysis are presented in Table 27 and Table 28. It is worth noting that the LCOE calculation is for the electrical generation component only and the cost of the heat recapture and recovery was taken out of the total installed system cost. PacifiCorp provided the natural gas pricing and the weighted average cost of capital (WACC) assumptions.

C.1 Key Assumptions

Table 27 Reciprocating Engines LCOE – Key Assumptions[27]

DG Resource Costs	Units	2021	2030	2040	Notes
Installed System Cost	$/W	$2.69/W	$2.79/W	$2.91/W	• EPA, Catalog of CHP Technologies, March 2015, pg. 2-15 • Assumed cost for electrical generation only, system cost was reduced by 10% to exclude heating generation costs.
Asset Life	Years	25	25	25	
Capacity Factor	%	85%	85%	85%	Navigant Assumption
Variable O&M	$/MWh	$20	$20	$20	ICF International Inc., Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment, pg. 92
Fuel Cost	$/MMBtu	PacifiCorp Gas Forecast	PacifiCorp Gas Forecast	PacifiCorp Gas Forecast	Provided by PacifiCorp
WACC	%	6.57%	6.57%	6.57%	Provided by PacifiCorp

[26] http://apps.leg.wa.gov/WAC/default.aspx?cite=480-109-100

[27] EPA, Catalog of CHP Technologies: www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies.pdf; ICF, Combined Heat and Power Policy Analysis, www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002.pdf

Table 28 Micro-turbines LCOE – Key Assumptions[28]

DG Resource Costs	Units	2019 2021	2028 2030	2038 2040	Notes
Installed System Cost	$/W	$2.55/W	$2.55/W	$2.54/W	• EPA, Catalog of CHP Technologies, March 2015, pg. 2-15 • Assumed cost for electrical generation only, system cost was reduced by 5% to exclude heating generation costs.
Asset Life	Years	25	25	25	Assumption
Capacity Factor	%	85%	85%	85%	Assumption
Variable O&M	$/MWh	$20	$20	$20	ICF International Inc., Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment, pg. 92
Fuel Cost	$/MMBtu	PacifiCorp Gas Forecast	PacifiCorp Gas Forecast	PacifiCorp Gas Forecast	Provided by PacifiCorp
WACC	%	6.57%	6.57%	6.57%	Provided by PacifiCorp

C.2 Results

The results of the LCOE analysis are presented in Table 29, with levelized costs estimated to range from ~$93/MWh to ~$119/MWh over the forecast period, varying by year and technology.

Table 29 LCOE Results – Electric Component Only

Technology	Units	2021	2030	2040
Reciprocating Engines	$/MWh	93.4	106.3	118.7
Microturbines	$/MWh	93.8	104.4	114.6

[28] EPA, Catalog of CHP Technologies: www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies.pdf; ICF, Combined Heat and Power Policy Analysis, www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002.pdf

APPENDIX D. DETAILED NUMERIC RESULTS

D.1 Utah

Table 30. Utah – Incremental Annual Market Penetration (MW AC) – Base Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.5	0.6	0.5	0.6	0.6	0.7	0.7	0.6	0.5	0.6	0.5	0.5	1.0	0.4	0.7	0.9	0.3	0.6	0.5	0.2
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.2	0.0	0.1	0.1	0.2	0.2	0.2	0.1	0.1	0.2	0.1	0.1	0.4	0.2	0.3	0.4	0.2	0.2	0.3	0.1
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	32.2	1.7	1.7	2.0	1.7	2.0	2.2	2.4	2.0	1.8	1.8	18.7	39.8	48.8	44.2	71.3	66.3	59.0	65.6	73.1
PV	Commercial	3.2	1.2	1.2	4.9	5.4	5.8	7.9	14.2	22.8	20.5	25.3	19.5	17.9	17.6	16.4	16.0	14.4	12.2	15.0	13.6
PV	Industrial	0.3	0.1	0.1	0.5	0.8	0.8	0.8	0.8	0.9	0.8	1.3	1.8	3.2	4.1	3.2	2.5	2.7	2.1	2.3	1.8
PV	Irrigation	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 31. Utah – Incremental Annual Market Penetration (MWh) – Base Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	3781	4150	3761	4127	4115	5267	5466	4207	3372	4339	3932	3703	7133	3204	4938	6867	2409	4248	4040	1344
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	1441	349	980	1023	1125	1547	1368	804	792	1199	1087	1024	2784	1328	2104	2610	1192	1640	2566	444
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	67855	3514	3501	4123	3566	4249	4570	5115	4247	3833	3876	39333	83838	102798	93138	150280	139691	124172	138081	153905
PV	Commercial	6687	2598	2588	10226	11306	12118	16587	30004	48111	43142	53214	41140	37728	37106	34613	33767	30332	25665	31694	28595
PV	Industrial	615	181	181	1101	1675	1619	1724	1642	1842	1636	2660	3750	6807	8636	6800	5256	5734	4339	4746	3873
PV	Irrigation	23	23	23	43	121	130	123	146	174	286	289	310	315	291	306	331	333	353	369	324
Wind	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 32. Utah – Incremental Annual Market Penetration (MW AC) – Low Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Reciprocating Engine	Industrial	0.4	0.4	0.2	0.1	0.0	0.3	0.2	0.1	0.2	0.2	0.1	0.2	0.2	0.1	0.2	0.3	0.1	0.1	0.2	0.1
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	1.3	1.4	1.4	1.6	1.4	1.6	1.8	2.0	1.6	1.5	1.5	1.7	1.5	1.9	2.0	19.0	20.9	35.0	28.2	45.6
PV	Commercial	3.2	1.2	1.2	3.3	6.0	5.6	5.1	5.4	8.3	11.3	11.3	14.9	15.2	22.4	16.5	17.0	16.2	16.2	11.2	15.9
PV	Industrial	0.1	0.1	0.1	0.3	0.8	0.7	0.7	0.6	0.6	0.6	0.5	0.7	0.5	0.6	0.9	1.6	2.0	3.0	3.1	2.3
PV	Irrigation	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 33. Utah – Incremental Annual Market Penetration (MWh) – Low Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	3248	2843	1697	530	220	2201	1333	723	1406	1349	1069	1247	1710	912	1161	2001	407	487	1260	491
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	1143	38	36	54	80	359	126	84	53	39	39	56	39	66	68	85	66	74	75	78
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	2824	2873	2862	3370	2915	3474	3736	4181	3472	3134	3168	3662	3259	4036	4160	39949	44112	73716	59475	96128
PV	Commercial	6665	2526	2517	6868	12589	11895	10757	11460	17383	23782	23754	31474	31985	47088	34668	35859	34158	34159	23559	33550
PV	Industrial	210	160	159	637	1616	1557	1458	1355	1331	1334	1070	1405	1157	1299	1948	3325	4292	6263	6484	4787
PV	Irrigation	22	23	23	27	107	128	121	114	94	91	69	194	196	215	226	244	246	261	212	284
Wind	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 34. Utah – Incremental Annual Market Penetration (MW AC) – High Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.5	0.6	0.6	0.7	0.8	0.8	1.0	0.9	0.8	0.9	0.8	0.8	0.7	0.7	0.8	0.6	0.5	0.5	0.6	0.3
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Micro Turbine	Industrial	0.2	0.1	0.2	0.2	0.3	0.3	0.4	0.3	0.3	0.3	0.3	0.3	0.9	0.6	1.3	1.7	1.0	0.9	1.2	0.3
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	32.2	2.2	2.2	2.6	2.2	2.6	2.8	11.8	39.6	46.8	60.7	56.3	62.6	56.9	63.4	91.9	79.8	89.0	97.8	79.2
PV	Commercial	1.3	1.3	2.2	7.9	15.6	30.9	33.7	23.3	17.0	15.2	13.0	12.8	11.6	13.1	11.8	16.9	15.0	17.7	27.7	26.4
PV	Industrial	0.5	0.1	0.3	1.1	1.0	1.0	1.5	2.4	3.7	3.0	3.3	2.5	1.7	2.0	1.6	2.0	1.8	2.1	2.0	3.1
PV	Irrigation	0.0	0.0	0.0	0.1	0.1	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.3	0.6	0.6	0.8	0.6
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 35. Utah – Incremental Annual Market Penetration (MWh) – High Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	3865	4664	4117	5163	6141	6035	7114	6519	5959	6458	6040	5820	5055	5014	5610	4536	3855	3744	4551	2447
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	1657	628	1579	1809	1915	2491	2691	2329	2426	2592	2502	2485	6542	4426	9622	12824	7164	7057	9102	1882
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	67855	4600	4582	5396	4668	5561	5981	24880	83475	98667	127926	118638	131777	119847	133595	193610	168113	187490	206101	166741
PV	Commercial	2736	2784	4544	16582	32930	65103	70999	49148	35809	31996	27364	26955	24525	27593	24906	35582	31687	37387	58408	55545
PV	Industrial	967	211	627	2259	2175	2160	3224	4985	7820	6362	6893	5174	3646	4259	3411	4206	3755	4507	4286	6625
PV	Irrigation	24	25	25	159	180	331	454	314	314	271	315	289	289	321	459	694	1260	1316	1704	1313
Wind	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

D.2 Oregon

Table 36. Oregon – Incremental Annual Market Penetration (MW AC) – Base Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.1	0.0	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.2	0.2	0.4	0.4	0.7	1.0	0.8	0.5	0.7
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.2	0.2	0.2	0.2	0.1	0.4	0.3	0.3
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	3.7	3.7	3.8	3.8	3.9	3.8	4.5	5.5	6.4	24.1	29.0	44.3	38.1	60.4	46.6	52.7	57.7	65.6	73.5	64.8
PV	Commercial	1.3	0.3	0.3	1.9	2.0	1.8	2.1	2.0	2.2	1.7	4.7	8.5	8.5	8.3	7.7	5.8	6.0	4.5	4.3	4.1
PV	Industrial	0.1	0.0	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.6	0.8	0.8	0.8	0.7	0.5
PV	Irrigation	0.1	0.0	0.1	0.1	0.1	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.5	1.0	1.3	1.3	1.2	1.1	0.8
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 37. Oregon – Incremental Annual Market Penetration (MWh) – Base Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	480	203	649	733	1388	1414	1734	1783	1861	1954	1997	1835	1732	2867	3233	5016	7467	5739	3918	5101
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	503	1704	1531	1388	1365	1252	1063	2930	2446	2489
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

PV	Residential	5956	5981	6072	6119	6199	6113	7143	8775	10307	38613	46499	71061	61170	96910	74791	84455	92527	105180	154919	136517
PV	Commercial	2023	484	490	3101	3148	2824	3394	3153	3560	2790	7468	13620	13597	13363	12355	9222	9695	7294	8952	8691
PV	Industrial	89	27	57	135	123	212	309	328	293	307	263	283	280	501	981	1311	1286	1232	1461	1048
PV	Irrigation	143	43	92	217	197	341	496	527	471	493	423	454	449	805	1575	2106	2067	1979	2347	1684
Wind	Residential	2	37	1	0	0	-3	1	1	0	1	1	1	23	27	22	28	22	41	24	25
Wind	Commercial	0	0	0	0	0	-1	0	0	0	0	0	180	191	242	216	227	187	235	171	143
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	9	9

Table 38. Oregon – Incremental Annual Market Penetration (MW AC) – Low Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	3.7	3.7	3.8	3.8	3.9	3.8	4.1	4.7	5.0	5.1	5.2	9.3	14.8	22.8	22.3	26.0	29.4	33.6	37.8	49.0
PV	Commercial	1.2	0.3	0.2	1.3	1.9	1.7	2.1	1.4	1.6	1.7	1.3	1.4	1.7	2.2	3.8	5.1	5.0	7.5	7.5	5.3

PV	Industrial	0.1	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.1	0.1	0.1	0.2	0.1	0.1	0.2	0.1	0.4
PV	Irrigation	0.1	0.0	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.2	0.6
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 39. Oregon – Incremental Annual Market Penetration (MWh) – Low Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	263	7	214	474	555	583	717	758	801	781	799	825	792	1300	1325	1635	1334	1373	1380	1382
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	5925	5947	6042	6095	6180	6113	6501	7604	7988	8210	8418	14862	23770	36615	35738	41771	47201	53931	79676	103168
PV	Commercial	1898	430	392	2145	3044	2779	3296	2170	2546	2657	2104	2290	2702	3547	6047	8159	8063	11993	15756	11174
PV	Industrial	84	25	29	131	119	102	177	239	202	211	251	225	179	237	247	218	211	276	310	774
PV	Irrigation	136	40	46	210	191	163	284	384	324	339	403	362	288	381	397	351	339	443	498	1244

Wind	Residential	1	2	1	0	0	-1	0	0	0	0	0	1	0	0	0	3	26	22	16	16
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	91	156
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 40. Oregon – Incremental Annual Market Penetration (MW AC) – High Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.1	0.0	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.5	0.7	1.0	1.0	0.7	0.7	0.6	0.5	0.5	0.4	0.3
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.4	0.4	0.4	0.3	0.4	0.4	1.3	1.2	1.1
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	3.9	3.8	3.8	3.8	4.3	17.1	44.2	36.9	44.4	55.8	53.8	51.5	56.4	64.2	71.9	64.7	67.8	94.1	60.9	85.6
PV	Commercial	1.4	0.3	1.4	3.0	2.9	2.3	5.8	8.8	7.9	9.2	6.5	4.9	5.0	4.6	3.7	4.1	4.2	5.3	6.7	6.3
PV	Industrial	0.1	0.0	0.1	0.2	0.3	0.2	0.3	0.2	0.2	0.4	0.7	0.9	0.7	0.6	0.6	0.5	0.4	0.4	0.4	0.4
PV	Irrigation	0.1	0.0	0.1	0.3	0.4	0.4	0.4	0.3	0.3	0.7	1.2	1.5	1.1	1.0	0.9	0.8	0.6	0.7	0.6	0.7
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 41. Oregon – Incremental Annual Market Penetration (MWh) – High Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	885	156	1239	1441	1713	1706	2076	2126	2172	4073	5486	7251	7113	5515	5083	4681	3869	3484	3068	2208
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	1266	1453	1380	1413	1383	2619	3053	2728	2555	2651	3275	9370	9300	8504
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	6248	6031	6118	6154	6834	27400	70853	59229	71179	89439	86306	82512	90454	102880	115322	103709	108653	150872	128240	180351
PV	Commercial	2173	549	2200	4848	4576	3760	9351	14155	12737	14705	10467	7796	8061	7355	5958	6557	6763	8543	14175	13246
PV	Industrial	104	30	120	326	445	392	412	321	278	661	1158	1453	1108	1027	906	811	565	671	771	863
PV	Irrigation	166	47	193	523	715	630	662	516	447	1063	1860	2335	1781	1650	1456	1303	907	1078	1239	1387
Wind	Residential	9	41	2	1	0	-3	1	1	0	3	31	27	36	40	41	42	33	43	25	26
Wind	Commercial	1	1	1	0	0	-1	0	0	202	205	228	250	260	274	244	253	206	254	183	184
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	4	16	14	15	15	11	10

D.3 Washington

Table 42. Washington – Incremental Annual Market Penetration (MW AC) – Base Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.1	0.0	0.1	0.1	0.1	0.1	0.0	0.0	0.1	0.1	0.1	0.2	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.1
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	1.4	0.2	0.2	0.3	0.2	0.3	0.3	0.3	0.2	0.3	0.3	0.4	0.3	0.4	0.4	0.4	0.4	3.9	8.4	9.9
PV	Commercial	0.1	0.1	0.1	0.2	0.1	0.2	0.2	1.0	1.0	1.8	2.5	5.7	4.6	4.4	3.2	3.7	2.5	2.4	2.7	1.8
PV	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.4	0.5	0.6	0.6	0.5	0.5	0.3
PV	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.3	0.4	0.5	0.5	0.5	0.4	0.3
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 43. Washington – Incremental Annual Market Penetration (MWh) – Base Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	1109	216	775	670	516	445	371	350	516	757	748	1134	2090	1457	1426	1441	1284	1261	1178	626
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	459	-4	209	306	263	360	285	251	267	232	265	204	873	682	578	828	471	608	616	281
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	2551	396	349	458	341	461	468	582	451	520	530	651	504	669	675	805	639	7117	17701	20867
PV	Commercial	251	267	235	309	230	311	316	1722	1779	3220	4457	10392	8255	7968	5773	6730	4521	4327	5633	3814
PV	Industrial	23	24	21	28	21	28	29	36	222	239	213	229	223	659	915	1070	1009	943	971	691
PV	Irrigation	20	21	19	24	18	25	25	31	193	208	185	199	193	572	795	929	876	819	843	600
Wind	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 44. Washington – Incremental Annual Market Penetration (MW AC) – Low Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040

Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.1	0.1	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.1	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	1.2	0.2	0.1	0.2	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3
PV	Commercial	0.1	0.1	0.1	0.2	0.1	0.2	0.2	0.2	0.5	0.7	0.9	0.8	0.7	2.0	2.1	3.9	2.8	4.1	4.0	2.8
PV	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.3
PV	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 45. Washington – Incremental Annual Adoption (MWh) – Low Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Reciprocating Engine	Industrial	906	-15	155	398	201	351	205	191	144	141	241	258	335	148	367	285	251	275	279	53
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	406	261	303	420	9
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	2174	302	267	350	261	352	358	445	344	397	405	497	385	511	516	615	489	571	676	675
PV	Commercial	242	258	227	299	222	300	305	379	874	1237	1575	1403	1324	3658	3864	7136	5063	7370	8389	5876
PV	Industrial	22	23	21	27	20	27	28	35	27	31	163	183	178	158	201	180	171	185	437	561
PV	Irrigation	19	20	18	24	18	24	24	30	23	27	141	159	154	137	174	156	148	160	379	487
Wind	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 46. Washington – Incremental Annual Market Penetration (MW AC) – High Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.2	0.0	0.1	0.1	0.2	0.2	0.2	0.3	0.2	0.3	0.2	0.2	0.1	0.1	0.2	0.1	0.1	0.1	0.1	0.1
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.3	0.4	0.4	0.3	0.3	0.1
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	3.2	0.3	0.3	0.4	0.3	0.4	0.4	0.5	0.4	0.4	0.4	0.5	0.4	0.6	8.6	11.3	10.0	8.7	12.5	10.9
PV	Commercial	0.1	0.2	0.1	0.2	0.4	1.4	4.3	5.4	4.2	3.9	3.4	3.1	2.5	2.0	2.0	2.3	2.4	3.1	4.0	3.7
PV	Industrial	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.1	0.2	0.4	0.5	0.6	0.5	0.4	0.4	0.3	0.3	0.2	0.3	0.3
PV	Irrigation	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.1	0.2	0.3	0.5	0.6	0.4	0.4	0.3	0.2	0.3	0.2	0.2	0.3
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 47. Washington – Incremental Annual Market Penetration (MWh) – High Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	1556	65	845	818	1324	1315	1529	2215	1423	1988	1253	1734	978	983	1236	855	665	688	664	415
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	569	122	466	430	390	611	805	711	676	680	676	594	663	1093	2205	2926	2766	2558	2209	1034

Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	5703	579	511	671	500	675	686	853	660	761	777	953	738	1154	15564	20409	18063	15823	26389	22939
PV	Commercial	261	278	245	322	685	2544	7702	9685	7537	7033	6207	5546	4445	3642	3609	4147	4330	5610	8368	7769
PV	Industrial	24	26	23	30	22	215	324	212	391	717	943	1158	844	777	671	515	522	449	559	642
PV	Irrigation	21	22	20	26	19	187	281	184	340	622	819	1006	733	675	583	447	453	390	486	557
Wind	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	36	65	66	51	43
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

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Table 48. Idaho – Incremental Annual Market Penetration (MW AC) – Base Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.3	0.2	0.4	0.5	0.3	0.3	0.3	0.3
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.1
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	2.1	0.3	0.2	0.2	0.3	0.3	2.5	4.3	4.9	5.5	4.7	5.3	5.7	6.3	6.9	5.5	7.9	6.2	6.6	9.6
PV	Commercial	0.2	0.0	0.2	0.3	0.3	0.8	1.1	1.3	1.2	1.1	0.9	0.7	0.6	0.7	0.6	0.5	0.6	0.8	0.7	0.9
PV	Industrial	0.1	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.7	0.7	0.7	0.6	0.4	0.5	0.3	0.3	0.3
PV	Irrigation	0.2	0.0	0.0	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.9	1.7	1.7	1.6	1.5	1.1	1.2	0.8	0.8	0.8
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 49. Idaho – Incremental Annual Market Penetration (MWh) – Base Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	597	121	603	760	871	972	952	1096	970	1074	910	1018	1959	1514	3027	3599	2485	2437	2327	2178
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	49	405	479	432	523	533	566	642	602	569	729	1454	1133	1156	1167	823
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	4289	586	446	507	580	659	5206	8859	10087	11334	9763	10872	11699	13096	14310	11364	16377	12867	13902	20219
PV	Commercial	476	97	323	636	572	1655	2286	2650	2531	2329	1954	1406	1218	1409	1146	1012	1317	1641	1560	1826
PV	Industrial	203	29	27	352	329	345	312	373	324	332	722	1399	1398	1366	1251	910	972	708	670	645
PV	Irrigation	501	72	68	869	810	850	770	919	798	820	1779	3449	3447	3369	3085	2245	2397	1746	1653	1590
Wind	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 50. Idaho – Incremental Annual Market Penetration (MW AC) – Low Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.1	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	1.1	0.2	0.2	0.2	0.2	0.3	0.3	2.3	3.6	3.3	3.8	2.9	3.1	3.4	5.1	4.1	4.2	2.8	4.8	5.2

PV	Commercial	0.2	0.0	0.1	0.3	0.3	0.3	0.7	0.7	0.7	1.0	1.0	0.7	0.9	0.6	0.6	0.8	0.5	0.5	0.5	0.5
PV	Industrial	0.1	0.0	0.0	0.1	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.3	0.4	0.4	0.6	0.6	0.4
PV	Irrigation	0.2	0.0	0.0	0.3	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.7	1.0	1.0	1.4	1.4	1.0
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 51. Idaho – Incremental Annual Market Penetration (MWh) – Low Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	373	14	288	324	381	413	400	583	473	717	594	590	856	566	704	707	504	670	663	130
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	2215	483	368	418	478	544	669	4718	7358	6812	7801	6059	6334	6981	10630	8426	8772	5729	10190	10859
PV	Commercial	393	92	220	620	557	661	1397	1467	1454	2105	2021	1433	1859	1322	1267	1610	1089	1074	1062	1034
PV	Industrial	159	26	20	254	318	334	302	270	217	271	210	223	271	357	612	821	816	1207	1225	855
PV	Irrigation	391	64	49	627	783	824	746	665	536	668	519	549	669	881	1509	2023	2011	2975	3021	2108

Wind	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 52. Idaho – Incremental Annual Market Penetration (MW AC) – High Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.1	0.0	0.1	0.1	0.1	0.1	0.2	0.3	0.3	0.5	0.4	0.5	0.5	0.4	0.3	0.4	0.2	0.2	0.2	0.1
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.4	0.8	0.6	0.5
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	2.0	0.3	0.3	0.3	2.3	6.9	8.2	5.1	5.5	6.0	6.5	7.2	7.6	6.0	8.8	6.9	7.0	7.4	7.7	8.0
PV	Commercial	0.2	0.1	0.3	0.9	1.9	1.8	1.2	0.9	0.7	0.6	0.5	0.6	0.6	0.9	0.8	1.4	1.2	1.5	1.7	2.1
PV	Industrial	0.1	0.0	0.1	0.2	0.2	0.2	0.5	0.7	0.6	0.6	0.6	0.4	0.4	0.4	0.3	0.3	0.3	0.4	0.4	0.6
PV	Irrigation	0.3	0.0	0.3	0.5	0.6	0.5	1.2	1.8	1.6	1.5	1.6	0.9	1.0	0.9	0.7	0.7	0.8	1.0	0.9	1.5
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 53. Idaho – Incremental Annual Market Penetration (MWh) – High Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	653	231	790	869	1063	1107	1500	2013	2510	3447	2765	3633	3438	3244	2268	2689	1736	1587	1826	868
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	290	27	332	392	464	585	614	650	997	1374	1467	1404	1413	1301	1139	2424	3005	5680	4440	3991
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	4028	721	550	624	4847	14231	16830	10542	11250	12341	13421	14783	15603	12392	18081	14292	14401	15335	16307	16814
PV	Commercial	500	103	586	1933	3991	3771	2417	1778	1478	1154	1038	1181	1335	1758	1639	2800	2480	3014	3666	4333
PV	Industrial	217	33	242	451	475	456	985	1483	1333	1274	1322	769	811	733	580	626	666	829	789	1286
PV	Irrigation	536	82	596	1113	1172	1125	2428	3656	3285	3142	3259	1896	2000	1808	1430	1543	1642	2045	1945	3171
Wind	Residential	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

D.5 California

Table 54. California – Incremental Annual Market Penetration (MW AC) – Base Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.0	0.1	0.1	0.0	0.1	0.0	0.1	0.1	0.0
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.1	0.1	0.1	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	1.0	1.4	1.8	2.2
PV	Commercial	0.3	0.1	0.3	0.3	0.4	0.3	0.4	0.5	0.5	0.6	0.7	0.8	0.9	0.6	1.2	0.8	1.5	1.0	1.1	2.1
PV	Industrial	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.1	0.3	0.3	0.2	0.4	0.2
PV	Irrigation	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.2	0.1	0.2	0.2	0.2	0.2	0.3	0.2	0.4	0.4	0.3	0.6	0.4
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 55. California – Incremental Annual Market Penetration (MWh) – Base Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	196	19	226	268	299	339	369	269	383	397	401	203	373	394	127	397	81	383	396	60
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	160	63	196	232	320	305	331	360	362	375	378	393	373	394	395	129	378	407	420	63
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	48	4	4	11	55	51	51	110	186	192	167	206	173	152	188	384	2149	2977	3774	4653
PV	Commercial	600	131	557	721	773	734	823	984	1071	1278	1419	1742	1942	1318	2573	1737	3212	2104	2230	4349
PV	Industrial	131	38	146	127	137	157	142	221	188	224	247	308	343	427	278	566	631	419	805	509
PV	Irrigation	196	56	219	190	204	235	211	330	281	335	369	460	513	638	415	845	943	626	1202	760
Wind	Residential	0	2	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1
Wind	Commercial	7	8	11	13	13	15	15	17	15	15	14	16	12	17	22	23	30	38	21	11
Wind	Industrial	0	1	1	1	1	1	2	2	2	2	2	2	1	2	3	3	3	2	2	1
Wind	Irrigation	1	3	3	4	4	5	5	5	5	5	5	4	5	4	4	4	4	3	4	4

Table 56. California – Incremental Annual Market Penetration (MW AC) – Low Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040

Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1
PV	Commercial	0.3	0.1	0.3	0.3	0.3	0.3	0.3	0.4	0.2	0.4	0.3	0.3	0.3	0.7	0.4	0.5	0.5	0.6	0.6	0.7
PV	Industrial	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.1
PV	Irrigation	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.1	0.1	0.2	0.3	0.2
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 57. California – Incremental Annual Market Penetration (MWh) – Low Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Reciprocating Engine	Industrial	127	67	150	202	223	250	200	276	274	281	159	275	113	255	255	90	242	60	254	264
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	120	61	145	192	189	210	223	238	234	239	237	244	227	240	239	256	242	60	254	264
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	45	4	4	4	34	49	44	39	31	56	129	136	104	142	146	122	152	127	129	131
PV	Commercial	575	129	569	664	545	610	667	791	529	933	587	691	671	1409	935	1087	1084	1246	1329	1433
PV	Industrial	129	29	132	144	109	138	121	138	94	153	98	190	119	145	269	198	195	226	426	280
PV	Irrigation	193	44	197	215	163	206	181	207	141	228	147	283	178	217	401	296	291	338	636	419
Wind	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1
Wind	Commercial	3	7	9	10	10	13	12	13	13	12	12	12	10	10	9	10	8	8	3	4
Wind	Industrial	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Wind	Irrigation	1	2	2	2	3	3	4	4	4	5	4	4	3	4	3	3	3	3	1	1

Table 58. California – Incremental Annual Market Penetration (MW AC) – High Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.1	0.1	0.1	0.1	0.0	0.1	0.1	0.1	0.0	0.1	0.0	0.1	0.1
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.1	0.1	0.1
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.8	1.2	1.6	1.9	2.4	2.7	2.9	3.1	2.7
PV	Commercial	0.3	0.1	0.4	0.6	0.6	0.7	1.2	0.5	0.9	1.1	1.2	0.8	1.5	1.0	1.9	1.2	1.2	1.4	1.5	1.6
PV	Industrial	0.1	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.1	0.3	0.3	0.2	0.4	0.3	0.5	0.3	0.3	0.3
PV	Irrigation	0.1	0.0	0.1	0.2	0.1	0.2	0.3	0.2	0.3	0.3	0.2	0.4	0.4	0.3	0.6	0.4	0.7	0.4	0.5	0.5
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 59. California – Incremental Annual Market Penetration (MWh) – High Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	206	100	263	313	351	400	299	450	454	472	478	238	446	471	472	151	451	101	471	485
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	186	96	237	351	333	378	413	450	454	472	478	498	472	499	500	531	106	512	527	541

Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	56	5	4	69	107	290	274	201	169	174	177	1700	2540	3339	4151	5068	5872	6169	6581	5585
PV	Commercial	633	153	905	1187	1204	1553	2594	1148	1965	2308	2553	1689	3150	2068	4045	2665	2668	3000	3163	3371
PV	Industrial	136	38	170	227	199	323	451	344	379	448	272	560	621	412	807	537	994	644	680	726
PV	Irrigation	203	56	254	340	298	483	674	513	567	670	407	837	928	616	1207	802	1485	962	1016	1084
Wind	Residential	0	2	0	0	0	0	0	0	0	1	1	1	1	2	2	2	2	2	1	1
Wind	Commercial	8	10	12	14	15	17	18	17	18	16	32	26	47	41	40	40	37	36	18	16
Wind	Industrial	1	1	1	1	2	2	2	2	2	2	4	4	3	3	3	3	3	3	1	2
Wind	Irrigation	2	3	4	5	5	5	6	6	6	5	6	6	4	7	8	11	13	14	7	10

D.6 Wyoming

Table 60. Wyoming – Incremental Annual Market Penetration (MW AC) – Base Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.6	0.6	0.5
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	0.1	0.0	0.0	0.0	0.0	0.0	1.1	2.7	3.0	3.7	4.5	5.4	5.5	6.1	5.2	5.9	6.3	7.1	7.8	4.6
PV	Commercial	0.4	0.2	0.3	0.6	1.2	2.3	2.3	2.3	2.0	1.5	1.6	1.2	1.0	1.0	1.1	1.3	1.1	1.8	1.7	1.3
PV	Industrial	0.2	0.0	0.0	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.6	1.2	1.3	1.3	1.3	1.1	0.8	0.7	0.5
PV	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 61. Wyoming – Incremental Annual Market Penetration (MWh) – Base Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	0	0	0	0	0	0	239	2154	2107	2234	2276	2274	2119	2024	2043	2107	3050	4193	4258	4091
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

PV	Residential	111	100	49	61	46	74	2282	5938	6430	8058	9750	11658	11910	13200	11352	12767	13611	15308	16380	9765
PV	Commercial	781	350	568	1329	2609	4953	5013	4935	4418	3238	3368	2525	2123	2239	2339	2792	2328	3824	3478	2794
PV	Industrial	325	83	41	583	712	671	682	717	713	650	634	1272	2499	2916	2865	2719	2332	1706	1506	1105
PV	Irrigation	15	4	2	26	32	30	31	33	32	30	29	58	114	132	130	124	106	77	68	50
Wind	Residential	1	7	0	0	0	0	0	0	0	0	4	3	4	5	5	5	5	5	3	2
Wind	Commercial	-2	1	0	0	0	0	0	0	0	222	234	257	268	284	293	305	248	309	133	157
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 62. Wyoming – Incremental Annual Market Penetration (MW AC) – Low Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.3	0.3
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	1.1	1.6	2.0	2.5	2.9	2.3	3.8	3.0	4.7	4.7	3.6	3.1
PV	Commercial	0.3	0.2	0.2	0.6	0.5	1.3	1.8	1.3	1.8	1.8	1.2	1.7	1.1	1.1	1.1	1.1	1.2	0.9	0.9	0.2

PV	Industrial	0.1	0.0	0.1	0.1	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.4	0.6	0.8	1.2	0.7
PV	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 63. Wyoming – Incremental Annual Market Penetration (MWh) – Low Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1257	2149	2170
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	58	93	46	57	43	58	182	245	2296	3461	4373	5386	6299	5049	8266	6593	10274	10192	7667	6594
PV	Commercial	755	332	364	1294	1084	2871	3881	2885	3989	3979	2662	3619	2341	2389	2287	2319	2558	2051	1983	464
PV	Industrial	155	74	110	249	692	650	664	511	406	525	511	447	528	471	487	779	1272	1720	2425	1433
PV	Irrigation	7	3	5	11	31	30	30	23	18	24	23	20	24	21	22	35	58	78	110	65
Wind	Residential	0	4	0	0	0	0	0	0	0	0	0	0	0	2	3	3	3	2	2	1

Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	141	213	221	184	148
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 64. Wyoming – Incremental Annual Market Penetration (MW AC) – High Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.5	0.6	0.7	0.6	0.6	0.6	0.5	0.5	1.0
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.7	0.6	0.5	0.5
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	0.8	0.1	0.0	0.1	2.2	4.4	7.0	5.2	6.3	4.5	6.4	5.7	6.0	6.8	7.5	8.4	8.8	7.1	7.5	8.8
PV	Commercial	0.7	0.2	0.8	2.9	3.5	2.7	1.9	1.4	1.0	1.2	1.0	1.0	1.4	1.9	1.8	3.1	2.7	3.3	3.9	3.6
PV	Industrial	0.2	0.0	0.2	0.5	0.5	0.4	0.4	0.7	1.2	1.5	1.2	1.1	0.9	0.8	0.6	0.7	0.6	0.7	0.8	0.5
PV	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 65. Wyoming – Incremental Annual Market Penetration (MWh) – High Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	0	0	0	237	1784	1997	2071	2419	2524	2436	2383	4072	4680	5489	4456	4607	4454	3956	3949	7331
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1816	5383	4325	3802	3545
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	1678	192	95	118	4683	9609	15199	11165	13664	9692	13912	12282	13006	14753	16223	18222	19133	15327	15832	18617
PV	Commercial	1422	387	1635	6285	7626	5907	4126	3053	2185	2634	2208	2135	2966	4073	3798	6636	5742	7061	8142	7678
PV	Industrial	346	97	443	987	1012	902	916	1531	2673	3329	2519	2332	1936	1731	1275	1525	1214	1450	1702	954
PV	Irrigation	16	4	20	45	46	41	42	70	121	151	114	106	88	79	58	69	55	66	77	43
Wind	Residential	2	9	0	0	0	0	0	0	1	6	6	6	4	6	5	6	5	5	3	2
Wind	Commercial	-3	2	0	0	-1	0	114	265	269	302	284	348	352	320	274	333	320	276	215	198
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3	4

PacifiCorp: Private Generation Resource Assessment for long term planning

Updated Analysis Including ITC Changes

Jan 22, 2021

Introduction

Updated ITC Schedule

- Guidehouse prepared a Long-term Private Generation Resource Assessment on behalf of PacifiCorp.
- The purpose of this study is to support PacifiCorp's 2021 Integrated Resource Plan (IRP) by projecting the level of private generation resources PacifiCorp's customers might install over the next twenty years under base, low, and high penetration scenarios.
- This study built on Guidehouse's previous assessment which supported PacifiCorp's 2015, 2017, 2019, and 2021 IRP, incorporating updated load forecasts, market data, technology cost and performance projections.
- The study includes projections for PacifiCorp's six state territories: UT, OR, ID, WY, CA, WA.
- Navigant evaluated five private generation resources in detail in this report: Photovoltaic Solar, Small Scale Wind, Small Scale Hydro, Combined Heat and Power Reciprocating Engines, Combined Heat and Power Micro-turbines
- The Federal Investment Tax Credit (ITC) rules were changed in December 2020 as part of the US coronavirus relief package. We have updated the analysis to include the impacts of the new ITC rules. No other changes were made to the analysis inputs.

Federal Incentives

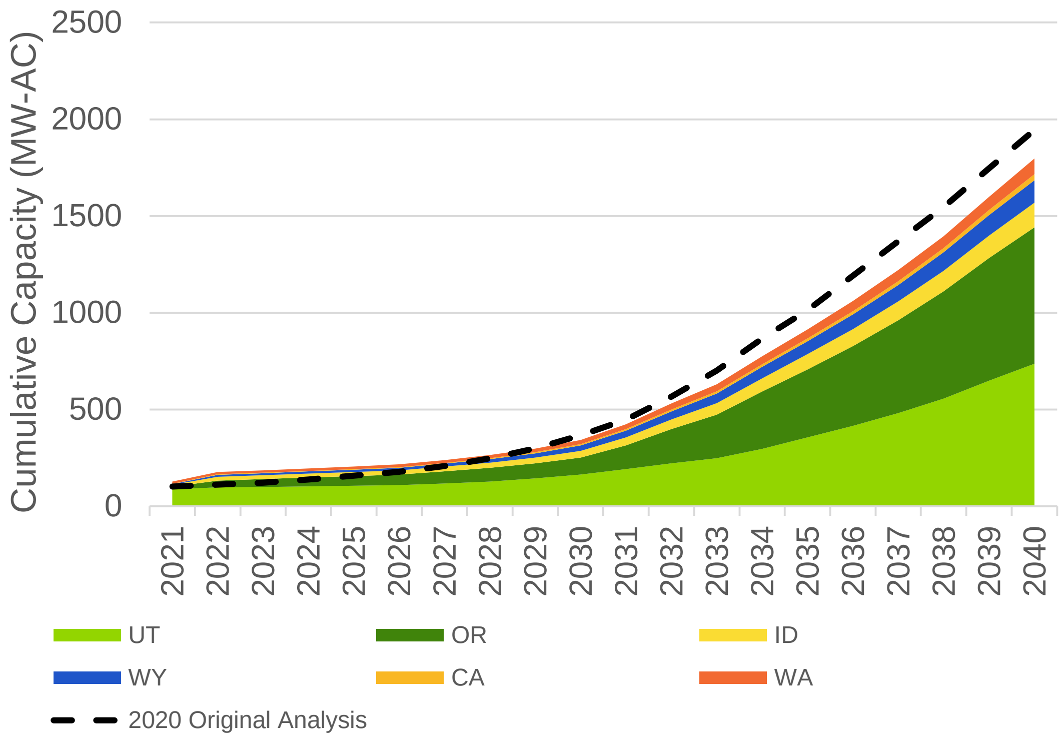
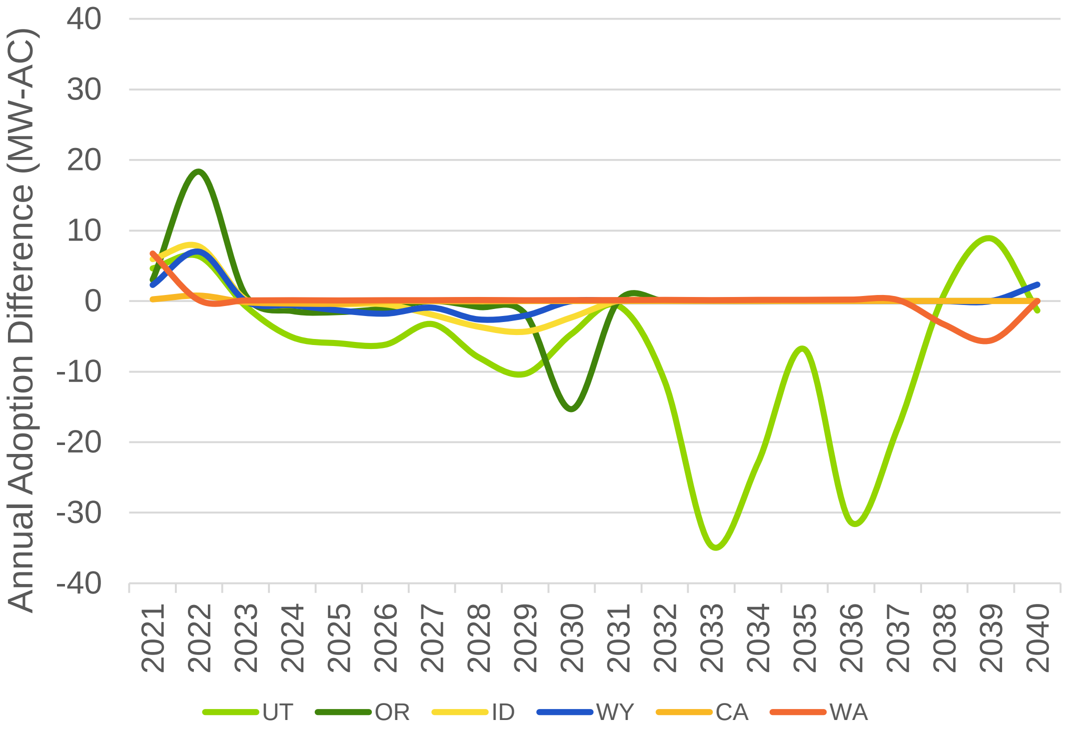
Updated ITC Schedule

Technology	2019	2020	2021	2022	2023	>2023
Recip. Engines	10%	10%	10%	0%	0%	0%
Micro Turbines	10%	10%	10%	0%	0%	0%
Small Hydro	0%	0%	0%	0%	0%	0%
PV - Com	30%	26%	26%	26%	22%	10%
PV - Res	30%	26%	26%	26%	22%	0%
Wind - Com	12%	0%	0%	0%	0%	0%
Wind - Res	30%	26%	26%	26%	22%	0%

Federal Investment Tax credit, http://energy.gov/savings/business-energy-investment-tax-credit-itc

Private Generation – Base Case

Updated ITC Schedule

Cumulative Capacity Installations, 2021-2040, Base Case	Annual Adoption Difference – Updated 2020 Analysis vs. Original 2020 Analysis
	

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APPENDIX M – RENEWABLE RESOURCES ASSESSMENT

A study on renewable resources and energy storage was commissioned to support PacifiCorp's 2021 Integrated Resource Plan (IRP). The 2020 Renewable Resources Assessment, prepared by Burns & McDonnell Engineering Company, Inc. (BMcD) 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. BMcD evaluated energy storage options of Pumped Hydro Energy Storage, Compressed Air Energy Storage, Lithium Ion Battery, Flow Battery, as well as wind and solar and combinations of these resource types.

This report compiles the assumptions and methodologies used by BMcD 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.

2020 Renewable Resources Assessment

PacifiCorp

2020 Renewable Resources Assessment
Project No. 125017

Revision 1
August 2020

2020 Renewable Resources Assessment

prepared for

PacifiCorp
2020 Renewable Resources Assessment
Salt Lake City, Utah

Project No. 125017

Revision 1
August 2020

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

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1.0 INTRODUCTION

PacifiCorp (Owner) retained Burns & McDonnell Engineering Company (BMcD) to evaluate various renewable energy resources in support of the development of the Owner's 2020 Integrated Resource Plan (IRP) and associated resource acquisition portfolios and/or products. The 2020 Renewable Resources Assessment (Assessment) is screening-level in nature and includes a comparison of technical capabilities, capital costs, and O&M costs that are representative of renewable energy and storage technologies listed below.

It is the understanding of BMcD 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 in order to refine design, major equipment selection, value engineering, and specific project scope adjustments.

1.1 Evaluated Technologies

- Single Axis Tracking Solar
- Onshore Wind
- Energy Storage
  - Pumped Hydro Energy Storage (PHES)
  - Compressed Air Energy Storage (CAES)
  - Lithium Ion Battery
  - Flow Battery
- Solar + Energy Storage
- Wind + Energy Storage

1.2 Assessment Approach

This report accompanies the Renewable Resources Assessment spreadsheet files (Summary Tables) provided by BMcD. The Summary Tables are broken out into three separate files for Solar, Wind, and Energy Storage options. The costs are expressed in mid-2020 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 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.

1.3 Statement of Limitations

Estimates and projections prepared by BMcD relating to performance, construction costs, and operating and maintenance costs are based on experience, qualifications, and judgment as a professional consultant. BMcD 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.

2.0 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 cost and O&M estimates are stated in mid-2020 US dollars (USD). Escalation is excluded.
- Estimates assume an Engineer, Procure, Construct (EPC) fixed price contract for project execution.
- 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.
- All performance estimates assume new and clean equipment. Operating degradation is excluded.
- Electrical scope is assumed to end at the high side of the generator step up transformer (GSU) unless otherwise specified in the summary table (most notably for CAES and PHES).
- Demolition costs were included for technology options with a shorter life cycle (Li-Ion, Solar, and Wind). Costs were developed based on Burns & McDonnell experience as well as published information. 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.

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. This 2020 study has based costs on recent bids that have accounted for the additional costs associated with current tariffs when available. While these costs are intended to represent a snapshot of 2020 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 appendices.

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 monthly, or even seasonal, 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 is able to 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. EPC Project Indirect Costs

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

- Construction/startup technical service
- Engineering and construction management
- Freight
- Startup spare parts
- EPC fees & contingency

2.3 Owner Costs

Allowances for Owner's costs are included in the pricing estimates. The cost buckets for Owner's costs varies slightly by technology but is broken out in the summary tables in Appendix A: Summary Tables.

2.4 Cost Estimate Exclusions

The following costs are excluded from all estimates:

- Financing fees

- Interest during construction (IDC)
- Escalation
- Performance and payment bond
- Sales tax
- Property taxes and insurance
- Off-site infrastructure
- Utility demand costs
- Salvage values

2.5 Operating and Maintenance Assumptions

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

- O&M costs are based on a greenfield facility with new and clean equipment.
- O&M costs are in mid-2020 USD.
- Property taxes allowance included for solar and onshore wind options.
- Land lease allowance included for PV and onshore wind options.
- Li-Ion battery O&M includes costs for additional cells to be added over time.

3.0 SOLAR PHOTOVOLTAIC

This Assessment includes 100 MW, and 200 MW single axis tracking photovoltaic (PV) options evaluated at two locations within the PacifiCorp services area.

3.1 PV General Description

The conversion of solar radiation to useful energy in the form of electricity is a mature concept with extensive commercial experience that is continually developing into a diverse mix of technological designs. PV cells consist of a base material (most commonly silicon), which is manufactured into thin slices and then layered with positively (i.e. Phosphorus) and negatively (i.e. Boron) charged materials. At the junction of these oppositely charged materials, a "depletion" layer forms. When sunlight strikes the cell, the separation of charged particles generates an electric field that forces current to flow from the negative material to the positive material. This flow of current is captured via wiring connected to an electrode array on one side of the cell and an aluminum back-plate on the other. Approximately 15% of the solar energy incident on the solar cell can be converted to electrical energy by a typical silicon solar cell. As the cell ages, the conversion efficiency degrades at a rate of approximately 2% in the first year and 0.5% per year thereafter. At the end of a typical 30-year period, the conversion efficiency of the cell will still be approximately 80% of its initial efficiency.

3.2 PV Performance

BMcD pulled Typical Meteorological Year (TMY) weather data for each site to determine expected hourly irradiance. BMcD then ran simulations of each PV option using PVSYST software. The resultant capacity factors for single axis tracking systems are shown in the Summary Tables. Inverter loading ratios (ILR) for each base plant nominal output at the point of electrical interconnect are indicated in Table 3-1.

Table 3-1: Inverter Loading Ratios in Assessment

Nominal Output	Single-Axis Tracking (SAT) DC/AC Ratio
100 MW	1.30
200 MW	1.30

There are different panel technologies which may exhibit different performance characteristics depending on the site. This assessment assumes poly-crystalline panels. The alternative, thin film technologies, are typically cheaper per panel, but they are also less energy dense, so it’s likely that more panels would be required to achieve the same output. In addition, the two technologies respond differently to shaded conditions. The two technologies are also impacted differently by current solar tariffs which has also impacted availability of the two.

Appendix B: Solar PVSYST Model Output (5MW) shows the PVSYST model output for a 4.2 MW block with the input assumptions, losses, and output summary. Appendix C: Solar Output Summary shows an additional output summary page unique for each solar option size and location. TMY data for each site as well as PVSYST 8760 outputs are provided to accompany this report outside of the formal report appendices.

3.3 PV Cost Estimates

Cost estimates were developed using in-house information based on BMcD project experience as an EPC contractor as well as an Owner's Engineer for EPC solar projects. Cost estimates assume an EPC project plus typical Owner's costs. A typical solar project cash flow is included in Appendix F: Generation Cash Flows.

PV cost estimates for the single axis tracking systems are included in the Summary Tables. Costs are based on the DC/AC ratios in Table 4-1 above, and $/kW costs, based on the nominal AC output, are shown in Appendix A: Summary Tables. The project scope assumes a high voltage interconnection for both the 100 and 200 MW options. Owner's costs include a switchyard allowance for the larger scale options, but no transmission upgrade costs or high voltage transmission interconnect line costs are included.

PV installed costs have steadily declined for years. The main drivers of cost decreases include substantial module price reductions, lower inverter prices, and higher module efficiency. However, recent US tariffs have had an impact on PV panels and steel imports. Pricing in the summary table is based on actual competitive EPC market quotes since these tariffs have been in place to take into account this impact. The panel tariffs only impact crystalline solar modules, however the availability of CdTe is limited for the next couple years, so it is prudent to assume similar cost increases for thin film panels until the impacts of the tariff are clearer.

Demolition costs for PV are included in the IRP Inputs and are meant to reflect the end of life decommissioning efforts. PV recycling in the U.S. is led by the Solar Energy Industries Association (SEIA), which has developed a national PV recycling program. This program works with several recycling companies along with regulators in order to abide by the Federal Resource Conservation and Recovery Act (RCRA), which is the governing legislation for the disposal of PV equipment. SEIA advises system owners to consider reuse and refurbishment when possible. However, when demolition and recycling is required, PV panels contain several materials that can be recovered. By weight, 80% of the panel consists of glass and aluminum. Other valuable materials include copper, silver, and semiconductor materials. Similar to the Li-Ion storage industry, many PV sites have not yet reached their end of useful life and therefore the recycling and materials resale market is still in its infancy.

The 2020 Assessment excludes land costs from capital and Owner costs. It is assumed that all PV projects will be on leased land with allowances provided in the O&M costs.

3.4 PV O&M Cost Estimate

O&M costs for the PV options are shown in the Summary Tables. O&M costs are derived from BMcD project experience and vendor information. The 2020 Assessment includes allowances for land lease and property tax costs.

The following assumptions and clarifications apply to PV O&M:

- O&M costs assume that the system is remotely operated and that all O&M activities are performed through a third-party contract. Therefore, all O&M costs are modeled as fixed costs, shown in terms of $MM per year.
- Land lease and property tax allowances are included based on in house data from previous projects.
- Equipment O&M costs are included to account for inverter maintenance and other routine equipment inspections.
- BOP costs are included to account for monitoring & security and site maintenance (vegetation, fencing, etc.).
- Panel cleaning and snow removal are not included in O&M costs.
- The capital replacement allowance is a sinking fund for inverter replacements, assuming they will be replaced once during the project life. It is a 15-year levelized cost based on the current inverter capital cost.

3.5 PV Plus Storage

The PV plus storage options combine the PV technology discussed in section 3.0 with the lithium ion batteries described in section 9.0. The battery storage size is set at approximately 50% of the total nominal output of the base solar options, with four hours of storage duration.

The storage system is assumed to be electrically coupled to the PV system on the AC side, meaning the PV and storage systems have separate inverters. However, there are use cases such as PV clipping that may be better served by a DC-DC connection. In a DC coupled system, the storage side would have a DC-DC voltage converter and connect to the PV system upstream of the DC-AC inverters. For a clipping application, a DC-DC connection allows the storage system to capture the DC output from the PV modules that may have otherwise been clipped by the inverters. Further study beyond the scope of this assessment would be required to determine the best electrical design for a particular application or site, but at this level of study, the capital costs provided are expected to be suitable for either AC or DC coupled systems.

Capital costs are show as add-on costs, broken out as project and owner's costs. These represent the additional capital above the PV base cost, intended to capture modest savings to account for shared system costs such as transformer(s) and switchgear. In addition, overlapping owner costs are eliminated or reduced. Finally, a line for O&M add-on costs is also included which can be added with the base PV O&M costs to determine overall facility O&M.

As with the Li-Ion battery options, the co-located storage option assumes an operation profile of one cycle per day, which is used for calculating the O&M costs.

4.0 ON-SHORE WIND

4.1 Wind Energy General Description

Wind turbines convert the kinetic energy of wind into mechanical energy, which can be used to generate electrical energy that is supplied to the grid. Wind turbine energy conversion is a mature technology and is generally grouped into two types of configurations:

- Vertical-axis wind turbines, with the axis of rotation perpendicular to the ground.
- Horizontal-axis wind turbines, with the axis of rotation parallel to the ground.

Over 95 percent of turbines over 100 kW are horizontal-axis. Subsystems for either configuration typically include the following: a blade/rotor assembly to convert the energy in the wind to rotational shaft energy; a drive train, usually including a gearbox and a generator; a tower that supports the rotor and drive train; and other equipment, including controls, electrical cables, ground support equipment and interconnection equipment.

Wind turbine capacity is directly related to wind speed and equipment size, particularly to the rotor/blade diameter. The power generated by a turbine is proportional to the cube of the prevailing wind, that is, if the wind speed doubles, the available power will increase by a factor of eight. Because of this relationship, proper siting of turbines at locations with the highest possible average wind speeds is vital.

Appendix D: Wind Performance Information includes NREL wind resource maps for Idaho, Oregon, Utah, Washington, and Wyoming with the locations of interest marked as provided by Owner.

4.2 Wind Performance

This Assessment includes 200 MW onshore wind generating facilities in Idaho, Oregon, Utah, Washington, and Wyoming service areas. BMcD relied on publicly available data and proprietary computational programs to complete the net capacity factor characterization. Generic project locations were selected within the area specified by Owner.

The Vestas V150-4.0 wind turbine model were assumed for this analysis. The respective nameplate capacity, rotor diameter, and a hub height are provided in the Table 4-1. The maximum tip height of this package is under 500 feet, which means there are less likely to be conflicts with the Federal Aviation Administration (FAA) altitudes available for general aircraft. A generic power curve at standard atmospheric conditions for each of the sites was assumed for the V150-4.0. Note that this turbine is intended only to be representative of a typical International Electrotechnical Commission wind turbine.

Because this analysis assumes generic site locations, the turbine selection is not optimized for a specific location or condition. Actual turbine selection requires further site-specific analysis.

Table 4-1: Summary of Wind Turbine Model Information

	Vestas V150-4.0
Name Plate Capacity, MW	4.0
Rotor Diameter, meters	150
Hub Height, meters	105

Using the NREL wind resource maps, the mean annual hub height wind speed at each potential project location was estimated and then extrapolated using the wind profile power law for the appropriate hub height to determine a representative wind speed. Using a Rayleigh distribution and power curve for the turbine technology described above, a gross annual capacity factor (GCF) was subsequently estimated for each site for both turbine types.

Annual losses for a wind energy facility were estimated at approximately 17 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 (NCF) for each potential site. Ideally, a utility-scale generation project should have an NCF of 30 percent or better. The NCF estimates for the PacifiCorp service areas are shown in the Summary Tables and represent an average of the two evaluated technologies.

4.3 Wind Cost Estimate

The wind energy cost estimate is shown in the Summary Tables. A typical cash flow for a wind project is included in Appendix F: Generation Cash Flows. Cost estimates assume an EPC project plus typical Owner's costs. Costs are based on a 200 MW plant with 4.0 MW turbines (50 total turbines) and 105-meter hub heights.

- Equipment and construction costs are broken down into subcategories per PacifiCorp's request. These breakouts represent the general scale of a 200 MW wind project but are not intended to indicate the expected scope for a specific site.
- The EPC scope includes a GSU transformer for interconnection at 161 kV.

- Land costs are excluded from the EPC and Owner's cost. For the 2020 Study, it is assumed that land is leased, and those costs are incorporated into the O&M estimate. Cost estimates also exclude escalation, interest during construction, financing fees, off-site infrastructure, and transmission.

Demolition costs shown on the IRP Input Table are meant to represent the efforts to return the project site back to native conditions (i.e. re-grading the site to achieve suitable drainage and seeding disturbed areas consistent with surrounding areas). This includes the decommissioning and demolition of all wind turbines as well as the associated infrastructure (i.e. buildings, turbine foundations, access roads, transmission lines, etc.). Also included is the transportation cost associated with moving the turbines off-site to recycling or landfill locations. Demolishing turbine blades can be a difficult as they are made of tough resin and fiberglass. One method of decommissioning is to cut the blades up into 3 or more parts to make them easier to transport to landfills. Another method involves grinding the blades into small pellets that can used for decking, pallets, and piping. Along with PV and li-ion storage, wind turbines contain valuable components such as steel, copper, and other metals that ideally can be resold as part of the recycling process.

4.4 Wind Energy O&M Estimates

O&M costs in the Summary Tables are derived from in-house information based on BMcD project experience and vendor information. Wind O&M costs are modeled as fixed O&M, including all typical operating expenses including:

- Labor costs
- Turbine O&M
- BOP O&M and other fixed costs (G&A, insurance, environmental costs, etc.)
- Property taxes
- Land lease payments

A summary of the suggested planned maintenance activities for a utility-scale wind energy facility are presented in Table 4-2 below. These represent the minimum activities that Burns & McDonnell suggests to be performed on a recurring basis and represent a minimum standard of performance if high availability and/or extended useful life are required. For the avoidance of doubt, the frequencies noted in Table 4-2 represent a minimum recurrence interval; trending results, condition-based monitoring data, supplier recommendations, or other similar items may necessitate more frequent planned maintenance.

Table 4-2: Minimum Wind Farm Planned Maintenance Activities

Component	Activity	Min. Frequency
General	Visual inspection of exterior components (e.g., nacelle, tower, blades)	Semi-annual
	Tower weld inspections	3-year rotation
	External paint touch-up	As required
	Fastener inspections and re-torque	3-year rotation
	Condition monitoring system set-point review	Annual
	Supplier-recommended semi-annual maintenance	Semi-annual
	Monitoring via SCADA	24/7
Nacelle	Visual inspection of internal components	Per supplier manuals
	Functional tests of major components	Per supplier manuals
	Gearbox borescope inspections	3-year rotation
	Gearbox oil sampling and trending	Annual
	Gearbox oil and filter replacement	Per supplier manuals
	Bearing grease sampling and trending (e.g., main bearing, yaw bearings, blade bearings)	Per supplier manuals
	Lubrication flush and filter replacement	Per supplier manuals
	Inspection of emergency equipment	Annual
Foundations	Visual inspection of exterior components (including bolts, nuts, washers, concrete, and surroundings)	Semi-annual
	Re-application of anti-corrosion protective coating	As required
BOP	Visual inspection of infrastructure (e.g., roads, collection routes, gen-tie routes, substation)	Annual
	Visual inspection of electrical equipment (e.g., transformers, breakers)	Semi-annual
	Maintain drainage away from foundations / structures	As required
	Transformer oil testing and trending	Annual
	Infrared scanning on all transformers	Annual
	De-energized substation maintenance	3 years
	Revenue meter test / calibration	Semi-annual
	Visual inspection of met towers (including tower, instruments, and guys)	Annual
	Met tower instrument calibration	Bi-annual

An allowance for capital replacement costs is not included within the annual O&M estimate in the Summary Table. A capital expenditures budget for a wind farm is generally a reserve that is funded over the life of the project that is dedicated to major component failures. An adequate capital expenditures budget is important for the long-term viability of the project, as major component failures are expected to occur, particularly as the facility ages.

If a capital replacement allowance is desired for planning purposes, Table 4-3 shows indicative budget expectations as a percentage of the total operating cost. As with operating expenses, however, these costs can vary with the type, size, or age of the facility, and project-specific considerations may justify deviations in the budgeted amounts.

Table 4-3: Summary of Indicative Capital Expenditures Budget by Year

Operational Years	Capital Expenditure Budget
0 – 2	None (warranty)
3 – 5	3% – 5%
6 – 10	5% – 10%
11 – 20	10% – 15%
21 – 30	15% – 20%
31 – 40	20% – 25%

4.5 Wind Energy Production Tax Credit

Tax credits such as the production tax credit (PTC) and investment tax credit (ITC) are not factored into the cost or O&M estimates in this Assessment, but an overview of the PTC is included below for reference.

To incentivize wind energy development, the PTC for wind was first included in the Energy Policy Act of 1992. It began as a $15/MWh production credit and has since been adjusted for inflation, currently worth approximately $25/MWh.

The PTC is awarded annually for the first 10 years of a wind facility's operation. Unlike the ITC that is common in the solar industry, there is no upfront incentive to offset capital costs. The PTC value is calculated by multiplying the $/MWh credit times the total energy sold during a given tax year. At the end of the tax year, the total value of the PTC is applied to reduce or eliminate taxes that the owners would normally owe. If the PTC value is greater than the annual tax bill, the excess credits can potentially go unused unless the owner has a suitable tax equity partner.

Since 1992, the changing PTC expiration/phaseout schedules have directly impacted market fluctuations, driving wind industry expansions and contractions. The PTC is currently available for projects that begin construction by the end of 2020, but with a phaseout schedule that began in 2017. Projects that started construction in 2015 and 2016 will receive the full value of the PTC, but those that start(ed) construction in later years received reduced credits:

- 2017: 80% of the full PTC value
- 2018: 60% of the full PTC value
- 2019: 40% of the full PTC value
- 2020: 40% of the full PTC value (extended through Dec 31st, 2020)

To avoid receiving a reduction in the PTC, a “Safe Harbor” clause allowed for developers to avoid the reduction through an upfront investment in wind turbines by the end of 2016. The Safe Harbor clause allowed for wind projects to be considered as having begun construction by the end of the year if a minimum of 5% of the project’s total capital cost was incurred before January 1st, 2017.

Many wind farms were planned for construction and operation when it was assumed they would receive 100% of the PTC. However, with the reduction in the PTC, some of these projects are no longer financially viable for developers to operate. This may result in renegotiated or canceled PPAs, or transfers to utilities for operation.

4.6 Wind Plus Storage

The wind plus storage options combine the wind technology discussed in section 4.0 with the lithium ion batteries described in section 9.0. The battery storage size is set at approximately 50% of the total nominal output of the base solar options, with four hours of storage duration. The storage system is assumed to be electrically coupled to the wind system on the AC side, meaning the storage system has its own inverter.

Capital costs are shown as add-on costs, broken out as project and owner’s costs. These represent the additional capital above the wind base cost, intended to capture modest savings to account for shared system costs such as transformer(s) and switchgear. In addition, overlapping owner costs are eliminated or reduced. Finally, a line for O&M add-on costs is also included which can be added to the base wind O&M costs to determine overall facility O&M. As with the Li-Ion battery options, the co-located storage option assumes an operation profile of one cycle per day, which is used for calculating the O&M costs.

5.0 PUMPED HYDRO ENERGY STORAGE

5.1 General Description

Pumped-hydro Energy Storage (PHES) offers a way of storing off peak generation that can be dispatched during peak demand hours. This is accomplished using a reversable pump-turbine generator-motor where water is pumped from a lower reservoir to an upper reservoir using surplus off-peak electrical power. Energy is then recaptured by releasing the water back through the turbine to the lower reservoir during peak demand. To utilize PHES, locations need to be identified that have suitable geography near high-voltage transmission lines.

PHES provides the ability to optimize the system for satisfying monthly or even seasonal energy needs and PHES can provide spinning reserve capacity with its rapid ramp-up capability. Energy stored off-peak and delivered on-peak can help reduce on-peak prices and is therefore beneficial to consumers. PHES is well suited for markets where there is a high spread in day-time and night-time energy costs, such that water can be pumped at a low cost and used to generate energy when costs are considerably higher.

PHES also has the ability to reduce cycling of existing generation plants. Additionally, PHES has a direct benefit to renewable resources as it is able to 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.

5.2 PHES Cost Estimate

The PHES cost estimate was based on information provided by developers with limited scope definition. The costs were aligned as closely as possible based on the information provided. The reason information from developers was used versus using a generic site for PHES is due to the significant importance of geographical location for this type of energy storage. The cost estimate is shown in the Summary Tables. PHES can see life cycle benefits as their high capital cost is offset by long lifespan of assets.

6.0 COMPRESSED AIR ENERGY STORAGE

6.1 General Description

Compressed air energy storage (CAES) offers a way of storing off peak generation that can be dispatched during peak demand hours. CAES is a proven, utility-scale energy storage technology that has been in operation globally for over 30 years. CAES has two primary application methods: diabatic and adiabatic. To utilize CAES, the project needs a suitable storage site, either a salt cavern or mined hard-rock cavern. Salt caverns are the most preferred due to the low cavern construction costs, however mined hard-rock caverns are now a viable option in areas that do not have salt formations with the use of hydrostatic compensation to increase energy storage density and reduce the cavern volume required. CAES facilities use off-peak electricity to power a compressor train that compresses air into an underground reservoir at approximately 850 psig. Energy is then recaptured by releasing the compressed air, heating it, and generating power as the heated air travels through an expander.

6.1.1 Diabatic CAES

The difference between diabatic and adiabatic compressed air energy storage is in the method that the air is heated during generation. Diabatic CAES uses natural gas firing during generation via a gas turbine expansion train. Expansion train technology is also currently allowing for 30% H2 co-firing today and there are plans to develop the technology to support 100% H2. Round-trip efficiencies for diabatic CAES plants account for the energy input of the compressors as well as the energy input of the gas turbine. The energy input of the compressors is a design choice that will be made to balance cost and benefit. The round-trip efficiencies represented in this technology assessment are the efficiencies that can be reached at the cost that is shown. The heat input of the gas turbine during generation takes into account the heat rate of the turbine. The total energy output of the CAES plant is divided by the combination of these two figures (compressor energy and natural gas heat input) to calculate the round-trip efficiency. There have been two commercial CAES plants built and operated in the world. The first plant began commercial operations in 1978 and was installed near Huntorf, Germany. This 290 MW facility included major equipment by Brown, Boveri, and Company (BBC). The second is located near McIntosh, Alabama and is currently owned and operated by PowerSouth (originally by Alabama Electric Cooperative). This 110 MW facility began commercial operations in 1991 and employs Dresser Rand (DR) equipment. BMcD served as the Owner's engineer for this project. Diabatic CAES was removed from the evaluated options due to a shift in focus from developers to adiabatic CAES, which offers zero emissions storage.

6.1.2 Adiabatic CAES

A second application of compressed air energy storage is adiabatic, which uses no natural gas firing. Heat is recovered in a Thermal Energy Storage (TES) system while air is being compressed and this energy is released to heat the air during expansion and generation. During compression, air temperatures can reach up to 1000°F. The use of a TES (with oil, molten salt, etc..) to capture and release this heat allows the adiabatic CAES technology to work free of any fuel. This trait can decrease operating and construction costs. The absence of a gas turbine makes the calculation for round-trip efficiency the total energy output of the plant divided by the energy input of the compressors. Again, the size and energy requirements of the compressors is a design choice and the efficiencies represented in the technology assessment table are in conjunction with the costs also represented for each option. This technology is currently in service or in construction at 3 plants in Canada and Australia that total 25 MWh of storage capacity.

6.2 CAES Cost Estimates

The CAES cost estimates are shown in the Summary Tables. The costs were developed using generic Siemens and Hydrostor information that includes the power island, balance of plant and reservoir. Cost estimates assume an EPC project plus typical Owner's costs.

6.3 CAES Emissions Control

A Selective Catalytic Reduction (SCR) system is utilized in the diabatic CAES design along with demineralized water injection in the combustor to achieve NOx emissions of 2 parts per million, volumetric dry (ppmvd). A carbon monoxide (CO) catalyst is also used to control CO emissions to 2 ppmvd at the exit of the stack.

The use of an SCR and a CO catalyst requires additional site infrastructure. An SCR system injects ammonia into the exhaust gas to absorb and react with the exhaust gas to strip out NOx. This requires onsite ammonia storage and provisions for ammonia unloading and transfer. Adiabatic CAES is an emissions-free operation and does not require an emissions control system.

7.0 LIQUID AIR ENERGY STORAGE

7.1 General Description

Liquid air energy storage (LAES) uses electricity to drive a compression/refrigeration system that cools ambient air to approximately -320 °F, at which point it becomes a liquid. Liquefying air is advantageous because it achieves a volume reduction of approximately 700:1, meaning that large quantities of air can be stored in a significantly smaller volume. The liquid air is stored is until it is ready for use. Energy is then recaptured by re-vaporizing the liquid air and generating power as the heated air travels through a series of heat exchangers and expanders. The overall system is optimized by taking advantage of waste heat and “waste cold” in the process to reduce the amount of power required to liquefy the air.

LAES is a relatively new application in the energy storage market, however, the major equipment components and technologies used to liquefy, store, and re-vaporize the air have been widely used in many other industry applications for decades. Highview Power is one of the major LAES technology licensors in the market, having completed a LAES pilot plant in Heathrow, UK in 2011. This operational facility uses 350 kW to liquefy the air and provides 2.5 MWh of energy storage.

One of the major similarities between LAES and CAES is that the LAES technology also offers the ability to take advantage of off-peak power to charge the system that can then be later discharged during peak demand hours as described in Section 6.1.

Another similarity LAES shares with adiabatic CAES is a zero emissions process. When coupled with a renewable energy source to provide power for the system, LAES is considered a completely green technology, meaning that it does not have any emissions associated with the process. The system utilizes motor-driven equipment, as opposed to a gas turbine, for the main air compressors and other auxiliary equipment, so there are no emissions generated from combustion. Additionally, there are no hydrocarbons used in the process at all – only air – so fugitive emissions are also non-existent.

The LAES technology can be broken down into three (3) major systems; system charging (air liquefaction), energy storage (liquid air storage), and system discharge (power generation). Each of these systems are relatively independent of one another and therefore can be designed for different amounts of capacity, depending on the specific application and use case. For example, the charging section of the facility (air liquefaction) could be designed to produce liquid air at a rate sufficient enough to utilize any excess energy generated from renewable sources that otherwise would need to be curtailed due to transmission constraints. However, the discharge system could be designed to generate power at the rate required to meet the demand during peak times; this rate may or may not be the same as the charging rate.

The number of hours of available storage can be easily modified by adding additional liquid air storage tanks.

The following sections describe each of these three systems in more detail.

7.1.1 System Charging – Air Liquefaction

Ambient air is used as the source of air for the process. The air is sent through a series of compressors and heat exchangers to increase the pressure from atmospheric to approximately 850 psig. This initial air compression requires the largest amount of power usage for the entire process; there are other users within the process, but they are significantly smaller the main air compressor.

Contaminants in the air such as carbon dioxide, water, and particulates must be removed prior to the liquefaction process. Carbon dioxide and water will freeze at the cryogenic temperatures and could clog the piping, valves, or equipment. The air flows through a set of molecular-sieve beds that adsorb the water and CO_2 from the air – this technology is very similar to the process used in liquefied natural gas (LNG) facilities. Once saturated, the molecular-sieve is regenerated with dry air and ready to be used again.

A common process used to liquefy air is the Claude cycle. In the Claude cycle, the air acts as the process fluid to be cooled as well as the refrigerant. The high pressure air is let-down across an expander and/or valve to low pressure. This rapid reduction in pressure creates a cooling effect, known the Joule-Thompson (JT) effect, and a portion of the air becomes the liquid air product. Any air that is not liquefied is used as a refrigerant to further cool the system and is recycled to go through the process again. This is a well-known and widely industry-recognized process for liquefying air.

7.1.2 Energy Storage – Liquid Air Storage

Once the air is liquefied, it must be stored until ready for use. A benefit that LAES provides over CAES is that a specialized storage site, such as a salt cavern, is not required. Liquid air is stored in field-erected, insulated, cryogenic, storage tanks. These tanks are very similar to the storage tanks used to store other cryogenic liquids (such as liquid nitrogen or liquefied natural gas) and are widely utilized the in the oil, gas, and chemicals industry. By not depending on the geological formations of the site for storage, LAES facilities can be built in any location in which sufficient space is available.

Although the tanks are very well insulated, there will be some amount of the liquid air that “boils-off” as the system sits stagnant. Fortunately, since the contents of the storage system are only air (nitrogen, oxygen, argon, etc.), this “boil-off” vapor can be vented directly to atmosphere with no additional handling equipment required.

Depending on the amount of storage duration desired (i.e. hours of storage), the volume and quantities of storage tanks can be modified. Additional storage duration requires additional storage volume. When determining the size/capacity of the charging system, it is important to consider how long it will take to fill the storage tanks. If the charging duration is too long, it may be advantageous to increase the charging system capacity.

7.1.3 System Discharge – Power Generation

When ready to use to generate power, the liquid air is pumped from the storage tanks to a heat exchanger in which it is re-vaporized. The warm air then flows through series of heat exchangers and expanders, similar to CAES, in order to generate power via the expander. The rate in which power is generated is determined by the pumping capacity and the expander capacity. The higher discharge rate required, the larger the expander required.

Once the air is fully expanded, it is released back into the atmosphere.

8.0 GRAVITY ENERGY STORAGE

8.1 General Description

Gravity energy storage (GES) offers a technique of storing off peak generation that can be dispatched during peak demand hours. Like Pumped Hydro Storage, GES takes advantage of kinetic and potential energy via mass transfer between different elevations. This developing storage technology presents unique advantages in performance with round-trip efficiencies of approximately 80-90%. GES's largest competing technology is pumped-hydro storage due to similarities in fundamental design. However, GES has little to no site restrictions and can be integrated into any high voltage transmission grid while maintaining an insignificant environmental impact over the storage system's lifespan. Currently, storage capabilities range from 6-14 hours. In addition, gravity storage caries a small land footprint per kWh, thus increasing storage capability per acre.

GES technology is currently in small-scale international operation but is not yet available on a commercial scale. However, due to the growing global demand for large-scale storage options, there is burgeoning interest in the use of GES as a commercial storage solution. CapEx for GES depends on the design of the system and is customizable to balance the economic and performance goals of the project. GES has a large upfront capital cost but does not require as much ongoing CapEx throughout the life of the project due to minimal degradation. The future success of GES systems will depend on their ability to compete with other emerging energy storage methods in the long term.

8.1.1 Vertical Shaft Gravity Energy Storage

Vertical shaft (VS) GES systems consist of a shaft of large diameter, a piston, and other common operational components such as a pump-turbine, generator, etc. The water that fills the large shaft below the piston serves as a medium for energy transfer. The system operates on the simple function of pumping water to hydraulically lift a piston fitted within the large shaft. The steel piston is filled with reinforced rock and concrete materials. A reversible pump-turbine essentially creates a closed-circuit and converts grid power to potential energy by pumping water into the large shaft to raise the piston. During peak demand, the stored potential energy can be converted back into electrical energy by the descending piston that then allows the water under pressure to transfer back through the turbine, and ultimately back onto the grid.

In 2013 a Santa Barbara, California based company, Gravity Power, planned to construct its first commercial GES demonstration in Penzberg, Germany designed with a power shaft depth of 500-m and a 30-m diameter. These parameters produce an equivalence of 160 MWh (40 MW for 4 hours of bulk energy storage and requires a power consumption of 40 MW for a charge time of approximately 5 hours). This project is expected to have a lifetime of at least 50 years. The total cost estimate of this system was estimated at $1,100/kWh or $4,400 kW. Because general planning for a GES can take 2+ years with an additional 3-4 years of construction, this GES project is expected to be operational within the next few years.

8.1.2 Crane-Lift Gravity Energy Storage

A second application of GES employs the elevation of rock or concrete masses by crane to create a tower where potential energy is stored via elevation gain. Electric motors power the lifting of blocks to various levels that then create a tower. The total allowable energy storage is relative to tower height mass of the blocks, and the quantity of the blocks that can fit under the cranes. Energy from the grid is used to lift blocks and during hours of peak demand, energy is returned to the grid when the cranes lower the blocks. The force of gravity pulls the blocks downward, maintaining a constant speed of descent which creates kinetic energy that is converted to electrical energy by turning the electric generator. Since the mass of the blocks affects the CapEx of the cranes, the most cost effective way to increase power and energy capacity for this system is to increase the height of the tower and the velocity at which the blocks descend.

Energy Vault, a Swiss-based company specializing in utility-scale gravity-based energy storage, partnered with Indian energy provider, Tata Power, to deploy a 35-MW system in 2018. Energy Vault has developed a six-arm crane with capability to lift 35T (5,000 concrete blocks) to a height of ~30 stories. The system holds a round-trip efficiency between 80-90%. The storage system's capability maintains ranges of 20-35-80 MWh storage capacity and a 4-8MW of power discharge for 8-16 hours. A 30+ year lifespan is expected for this size GES system. Though this system is small-scale when considering the possible capabilities of its technology, its appeal has propelled Energy Vault and other companies to push the boundaries of crane-lift GES systems. This GES system may be more commonly utilized in the coming years due to large storage capacities, efficiency, low O&M costs, and sparse site restrictions. However, the technology is new, and the concern of its ability to compete with other new storage proposals produced in the long term remains.

8.1.3 Rail Energy Storage

Rail energy storage (RES) similarly takes advantage of potential energy to store and kinetic energy to discharge energy like Pumped Hydro Storage and the other GES technologies, with a simpler approach and less infrastructure. RES does not require water as a working fluid like pumped hydro and does not involve intensive extraction of materials during the construction process. RES has the potential to have lower CapEx and O&M expenses than other current energy storage options in certain topographical areas. RES storage facilities perform at approximately 80% round-trip operating efficiency while continuously delivering energy for up to 8 hours.

This storage solution utilizes rail cars that haul large masses (typically concrete or rock masses) back and forth between storage yards to store excess energy in times of low demand and easily disperse that energy during peak demand. RES uses surplus electrical energy from nearby renewable plants to power the increase in elevation of rail cars during hours of low demand, which creates potential energy. During hours of peak demand, the rail cars descend back downhill via gravity. This process converts the stored potential energy back into kinetic energy through regenerative braking, a technology commonly seen in electric vehicles. Regenerative braking utilizes the motor as a generator and converts lost kinetic energy from deceleration back into electrical that can be returned to the grid.

In April of 2016, Advanced Rail Energy Storage (ARES), a Santa-Barbara, California based energy startup had its first commercial-scale project approved on behalf of the Bureau of Land Management. The small-scale project, called ARES Nevada, planned for development on ~100 acres of public land near Pahrump, Nevada, has a 50-MW power capacity and can produce 12.5 MWh of energy. The estimated cost of the project is $55 million (at approximately $4,400/kWh) with an expected lifespan of 40 years. Though the project was scheduled to be in operation by late 2019 to early 2020, its success is still in question as it has not been in commercial use for an extended period. ARES is currently working on new designs to enable the storage system to perform on much steeper slopes along shorter distances which would allow the technology to be operable in more densely populated regions.

9.0 BATTERY STORAGE TECHNOLOGY

This Assessment includes standalone battery options for both lithium ion (Li-Ion) and flow battery technologies. Li-Ion options included 1 MW output with 30-minute, 1-hour, 4-hour, and 8-hour storage capacities as well as a 50 MW option with 4-hours of storage. A 1 MW, 1-hour, 4-hour, and 8-hour flow cell battery options were also included, along with a 20MW, 8-hour option. Additionally, the solar and wind summary tables include optional costs for adding Li-Ion battery capacity of 50% of the nominal renewable output to the site with 4-hours of storage.

9.1 General Description

Electrochemical energy storage systems utilize chemical reactions within a battery cell to facilitate electron flow, converting electrical energy to chemical energy when charging and generating an electric current when discharged. Electrochemical technology is continually developing as one of the leading energy storage and load following technologies due to its modularity, ease of installation and operation, and relative design maturity. Development of electrochemical batteries has shifted into three categories, commonly termed “flow,” “conventional,” and “high temperature” battery designs. Each battery type has unique features yielding specific advantages compared to one another.

9.1.1 Flow Batteries

Vanadium Redox batteries (VRB) and Zinc-Bromide (ZnBr) batteries are representative of commercially available flow battery technologies, but other technologies, such as iron flow batteries, are also available. Generally, flow batteries have lower round-trip efficiencies than Li-Ion batteries, however their theoretical performance does not degrade. This allows flow batteries to exhibit longer life spans than Li-Ion batteries without augmentation.

Developed in the early 1990’s by the University of New South Wales in Australia, VRBs employ a two tank, two pump system that contains vanadium-based electrolyte solutions on each side. Electrons are passed between the two solutions via an ion-permeable membrane to charge and discharge the battery. VRBs may be attractive for grid-scale applications due to their long lifetime and potential to scale power and energy capacity independently as needed for a given application. However, commercially available VRBs are generally modular in design, so the electrolyte volumes and discharge durations are limited by the form factor. As products and markets develop further, decoupled designs may arrive with greater design flexibility. The vanadium in the electrolyte does not degrade, so it can be reused/recycled after the useful life of the battery.

Zinc-Bromide batteries were developed in the 1970's by Exxon and are often referred to as "hybrid" flow batteries. ZnBr batteries use pumped liquid electrolyte in a single pump, single tank system. During charging, energy is stored by plating electrode surfaces with zinc. Discharging causes the zinc to oxidize and dissolve into the aqueous solution, which releases electrons to do work in the external circuit. The capacity of ZnBr batteries (and other plating style technologies) is dependent on electrode area as well as electrolyte volume. Commercially available units are modular designs with fixed power and energy ratings

9.1.2 Conventional Batteries

A conventional battery contains a cathodic and an anodic electrode and an electrolyte sealed within a cell container that can be connected in series to increase overall facility storage and output. During charging, the electrolyte is ionized such that when discharged, a reduction-oxidation reaction occurs, which forces electrons to migrate from the anode to the cathode thereby generating electric current. Batteries are designated by the electrochemicals utilized within the cell; the most popular conventional batteries are lead acid and Li-Ion type batteries.

Lead acid batteries are the most mature and commercially accessible battery technology, as their design has undergone considerable development since conceptualized in the late 1800s. The Department of Energy (DOE) estimates there is approximately 110 MW of lead acid battery storage currently installed worldwide. Although lead acid batteries require relatively low capital cost, this technology also has inherently high maintenance costs and handling issues associated with toxicity, as well as low energy density (yields higher land and civil work requirements). Lead acid batteries also have a relatively short life cycle at 5 to 10 years, especially when used in high cycling applications.

Li-Ion batteries contain graphite and metal-oxide electrodes and lithium ions dissolved within an organic electrolyte. The movement of lithium ions during cell charge and discharge generates current. Li-Ion technology has seen a resurgence of development in recent years due to its high energy density, low self-discharge, and cycling tolerance. Many Li-Ion manufacturers currently offer 20-year warranties or performance guarantees. Consequently, Li- Ion has gained traction in several markets including the utility and automotive industries.

Li-Ion battery prices are trending downward, and continued development and investment by manufacturers are expected to further reduce production costs. While there is still a wide range of project cost expectations due to market uncertainty, Li-Ion batteries are anticipated to expand their reach in the utility market sector.

9.1.3 High Temperature Batteries

High temperature batteries operate similarly to conventional batteries, but they utilize molten salt electrodes and carry the added advantage that high temperature operation can yield heat for other applications simultaneously. The technology is considered mature with ongoing commercial development at the grid level. The most popular and technically developed high temperature option is the Sodium Sulfur (NaS) battery. Japan-based NGK Insulators, the largest NaS battery manufacturer, installed a 4 MW system in Presidio, Texas in 2010 following operation of systems totaling more than 160 MW since the project's inception in the 1980s.

The NaS battery is typically a hermetically sealed cell that consists of a molten sulfur electrolyte at the cathode and molten sodium electrolyte at the anode, separated by a Beta-alumina ceramic membrane and enclosed in an aluminum casing. The membrane is selectively permeable only to positive sodium ions, which are created from the oxidation of sodium metal and pass through to combine with sulfur resulting in the formation of sodium polysulfides. As power is supplied to the battery in charging, the sodium ions are dissociated from the polysulfides and forced back through the membrane to re-form elemental sodium. The melting points of sodium and sulfur are approximately 98ºC and 113ºC, respectively. To maintain the electrolytes in liquid form and for optimal performance, the NaS battery systems are typically operated and stored at around 300ºC, which results in a higher self-discharge rate of 14 percent to 18 percent. For this reason, these systems are usually designed for use in high-cycling applications and longer discharge durations.

NaS systems are expected to have an operable life of around 15 years and are one of the most developed chemical energy storage technologies. However, unlike other battery types, costs of NaS systems have historically held, making other options more commercially viable at present.

9.2 Battery Emissions Controls

No emission controls are currently required for battery storage facilities. However, Li-Ion batteries can release large amounts of gas during a fire event. While not currently an issue, there is potential for increased scrutiny as more battery systems are placed into service.

9.3 Battery Storage Performance

This assessment includes performance for multiple Li-Ion options as well as one flow battery option. Li-Ion systems can respond in seconds and exhibit excellent ramp rates and round-trip cycle efficiencies. Because the technology is rapidly advancing, there is uncertainty regarding estimates for cycle life, and these estimates vary greatly depending on the application and depth of discharge. The systems in this

Assessment are assumed to perform one full cycle per day, and capacity factors are based on the duration of full discharge for 365 days. OEMs typically have battery products that are designed to suit different use-cases such as high power or high energy applications. The power to energy ratio is commonly shown as a C-ratio (for example, a 1MW / 4 MWh system would use a 0.25C battery product). However, the 8-hour battery option is based on a 0.25C system that is sized for twice the power and discharged for eight hours instead of four. While the technology continues to advance, commercially available, high energy batteries for utility scale applications are generally 0.25C and above.

Flow batteries are a maturing technology that is well suited for longer discharge durations (>4 hours, for example). Flow batteries can provide multiple use cases from the same system and they are not expected to exhibit performance degradation like lithium ion technologies. However, they typically have lower round trip efficiency than Li-Ion batteries. Storage durations are currently limited to commercial offerings from select vendors but are expected to broaden over the next several years. Performance guarantees of 20 years are expected with successful commercialization, but there is not necessarily a technical reason that original equipment manufacturer (OEM) and/or balance of plant (BOP) designs could not accommodate 30+ year life.

9.4 Regulatory Trends

Two (2) Federal Energy Regulatory Commission (FERC) Orders released in 2018 provide clarity on the role of storage in wholesale markets, and potentially drive continued growth. FERC Order 841 requires RTOs and ISOs to develop clear rules regulating the participation of energy storage systems in wholesale energy, capacity, and ancillary services markets. Prior to the final release of FERC 841, the California Public Utilities Commission introduced 11 rules to determine how multi-use storage products participate in California Independent System Operator (CAISO). FERC Order 842 addresses requirements for some generating facilities to provide frequency response, including accommodations for storage technologies. In addition, the Internal Revenue Service (IRS) is considering new guidance for the ITC that will impact projects combining storage with renewables.

Tariffs are a popular concern in the solar and storage market. With recent tariffs, uncertainty of how manufacturing abroad and nationally will be affected has crept into the industry. The “Section 301” tariffs are comprised of four lists of Chinese products that have been selected for tariffs between 15% and 30%. Raw materials used to create Li-Ion batteries and solar modules are already impacted by the Section 301 tariffs in affect and were set to increase from 25% to 30% in late Fall 2020 but has since been delayed. While these tariffs are beginning to increase, manufacturers in China have started to react and move production of solar and storage products outside of China to Mexico and India to avoid paying some of the tariffs.

9.5 Battery Storage Cost Estimate

The estimated costs of the Li-Ion and flow battery systems are included in the Summary Tables, based on BMcD experience and vendor correspondence. The key cost elements of a Li-Ion battery system are the inverter, the battery cells, the interconnection, and the installation. The capital costs reflect recent trends for overbuild capacity to account for short term degradation. The battery enclosures include space for future augmentation, but the costs associated with augmentation are covered in the O&M costs. It is assumed that land is available at an existing PacifiCorp facility and is therefore excluded from the cost estimate. These options assume the battery interconnects at medium voltage.

Flow battery estimates for the 1 MW options are based on iron flow battery technology. This is a modular design in which the OEM scope includes the tanks, electrolyte storage, and associated pumps and controls in a factory assembled package. The EPC scope includes the inverters, switchgear, MV transformer, and installation.

Demolition costs are meant to reflect the end of life decommissioning efforts. This includes discharging the batteries to the greatest extent possible, shutting the system down, final inspections, and physically disconnecting all electrical equipment. Following this, battery modules will need to be removed from the racks and placed on pallets for shipment to a recycling facility. Lithium-ion batteries are considered Class 9 hazardous waste and is currently treated like e-waste. Once at the recycling facility, a dissembler will break the module down into major subcomponents like steel, cells, copper, printed circuit boards, plastics, etc. The cells are then sent through either a shredding or smelting process to recover valuable metals. Once the cells go through this process, any remaining waste is not considered hazardous. Battery recycling costs vary significant depending on chemistry. Cobalt-based battery chemistries have higher recovery value and because they are more energy dense, typically involve handling less material. In all cases, the cost of disassembly and freight to the recycling facility is estimated to account for 70-90% of the total cost for recycling. Estimates, though, can vary significantly depending on metals pricing and competition in the battery recycling market.

9.6 Battery Storage O&M Cost Estimate

O&M estimates for the Li-Ion and flow battery systems are shown in the Summary Tables, based on BMcD experience and recent market trends. The battery storage system is assumed to be operated remotely.

The technical life of a Li-Ion battery project is expected to be 20 years, but battery performance degrades over time, and this degradation is considered in the system design. Systems can be "overbuilt" by including additional capacity in the initial installation, and they can also be designed for future augmentation. Augmentation means that designs account for the addition of future capacity to maintain guaranteed performance.

Overbuild and augmentation philosophies can vary between projects. Because battery costs are expected to continue falling, many installers/integrators are aiming for lower initial overbuild percentages to reduce initial capital costs, which means guarantees and service contracts will require more future augmentation to maintain capacity. Because costs should be lower in the future, the project economics may favor this approach. This assessment assumes minimal overbuild beyond system efficiency losses, and the O&M estimates include allowances for augmentation.

Battery storage O&M costs are modeled to represent the portions of performance guarantees and augmentation from recent BMcD project experience. The O&M cost for the Li-Ion systems include a nominal fixed cost to administer and maintain the O&M contract with an OEM/integrator, plus an allowance for calendar degradation fees. Calendar degradation represents performance degradation and subsequent augmentation expected to occur regardless of the system's operation profile, even if the batteries sit unused. Because calendar degradation is not tied to system operation or output, it is modeled as part of the fixed O&M.

Previously represented as variable O&M, estimates for Li-ion options account for cycling degradation fees are now also included in the fixed O&M section due to how the industry is now utilizing service agreements. Cycling the batteries increases performance degradation, so the performance guarantees provided by the OEM and/or integrator are commonly modeled to account for augmentation based on the expected operating profile. The augmentation O&M estimates in this assessment are based on an operation profile of one charge/discharge cycle per day and may not be valid for increased cycling.

Flow battery O&M costs are modeled around an annual service contract from the OEM or a factory trained third party. Costs are based on correspondence with manufacturers and are subject to change as the technology achieves greater commercialization and utilization in the utility sector. Unlike Li-Ion technologies, flow batteries generally do not exhibit calendar or cycle degradation, so there is not an augmentation O&M component per cycle. There is mechanical equipment that requires service based on an OEM recommended schedule, which is modeled as a levelized annual cost for the life of the system.

10.0 CONCLUSIONS

This Renewable Energy Resource Technology Assessment provides information to support PacifiCorp's power supply planning efforts. Information provided in this Assessment is screening level in nature and is intended to highlight indicative, differential costs associated with each technology. BMcD recommends that PacifiCorp use this information to update production cost models for comparison of renewable resource alternatives and their applicability to future resource plans. For specific project development efforts beyond IRP planning, PacifiCorp should pursue additional engineering studies to define project scope, budget, and timeline.

Renewable options include PV and wind systems. PV is a proven technology for daytime peaking power and a viable option to pursue renewable goals. PV capital costs have steadily declined for years, but recent import tariffs on PV panels and foreign steel may impact market trends. Wind energy generation is a proven technology and turbine costs dropped considerably over the past few years.

Utility-scale battery storage systems are being installed in varied applications from frequency response to arbitrage, and recent cost reduction trends are expected to continue. While PHES currently has the most installed capacity for energy storage as a whole, Li-Ion technology is achieving the greatest market penetration in the battery storage sector. This is aided in large part by its dominance in the automotive industry, but other technologies like flow batteries should be monitored, as well.

PacifiCorp's region has several geological sites that can support large scale storage options including PHES and CAES. This gives PacifiCorp flexibility in terms of energy storage. Smaller applications will be much better suited for battery technologies, but if a larger need is identified PHES or CAES could provide excellent larger scale alternatives. Both of these technologies benefit from economies of scale in regard to their total kWh of storage, allowing them to decrease the overall $/kWh project costs.

APPENDIX A – SUMMARY TABLES

APPENDIX B – SOLAR PVSYST MODEL OUTPUT (5MW)

APPENDIX C – SOLAR OUTPUT SUMMARY

APPENDIX D – WIND PERFORMANCE INFORMATION

APPENDIX E – DECLINING COST CURVES

APPENDIX F – GENERATION CASHFLOWS

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PACIFICORP RENEWABLE TECHNOLOGY ASSESSMENT SUMMARY TABLE
ENERGY STORAGE

PROJECT TYPE	Pumped Hydro								
BASE PLANT DESCRIPTION	**Swan Lake**	**Goldendale**	**Seminoe**	**Badger Mountain**	**Owyhee**	**Flat Canyon**	**Utah PS2**	**Utah PS3**	**Banner Mountain**
Nominal Output, MW	400	400	750	500	600	300	500	600	400
Nominal Output, MWh	3800	3800	7500	4000	4800	1800	4000	4800	3400
Capacity Factor (%)	31%	39%	40%	32%	32%	24%	32%	32%	34%
Startup Time (Cold Start), minutes	1.5	1.5	1.8	1.8	1.8	1.8	1.8	1.8	1.5
Full Pumping to Full Gen, minutes	4	4	3.5	3.5	3.5	3.5	3.5	3.5	0.67
Transition Time from Charging to Discharging, minutes	6	6	3.5	3.5	3.5	3.5	3.5	3.5	N/A
Availability Factor, %	90%	90%	95%	95%	95%	95%	95%	95%	95%
Technology Rating	Mature	Mature	Mature	Mature	Mature	Mature	Mature	Mature	Mature
Life Cycle, yrs	60	60	80	80	80	80	80	80	50+
Permitting & Construction Schedule, year (note 1)	6	10	8	6	8	8	6	8	7
ESTIMATED PERFORMANCE									
Base Load Performance @ (Annual Average)									
Net Plant Output, kW	400,000	400,000	750,000	500,000	600,000	300,000	500,000	600,000	400,000
Total Plant Storage, kWh (note 2)	3,800,000	4,800,000	7,500,000	4,000,000	4,800,000	1,800,000	4,000,000	4,800,000	3,400,000
Time for Full Discharge, hours	9.5	12.0	10	8	8	6	8	8	8.5
Time for Full Charge, hrs	9.5	14.0	12	9.5	9.5	7.2	9.5	9.5	10
Compression Power, MW (note 11)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Round-Trip Efficiency (%) (note 3)	78%	78%	80%	80%	80%	80%	80%	80%	81%
ESTIMATED CAPITAL AND O&M COSTS (Note 8)									
EPC Project Capital Costs, 2020 MM$ (w/o Owner's Costs)	**$814**	**$2,146**	**$1,625**	**$897**	**$1,203**	**$760**	**$1,108**	**$1,266**	**$900**
Owner's Costs, 2020 MM$	**$163**	**$429**	**$249**	**$137**	**$184**	**$116**	**$169**	**$194**	**$77**
Owner's Project Development	Included	Included	Included	Included	Included	Included	Included	Included	Included
Owner's Engineer	Included	Included	Included	Included	Included	Included	Included	Included	Included
Owner's Project Management	Included	Included	Included	Included	Included	Included	Included	Included	Included
Owner's Legal Costs	Included	Included	Included	Included	Included	Included	Included	Included	Included
Permitting and Licensing Fees	Included	Included	Included	Included	Included	Included	Included	Included	Included
Generation Switchyard (note 4)	Included in Project Costs	Included in Project Costs	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included
Transmission to Interconnection Point (note 4)	Included in Project Costs	Included in Project Costs	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included
Training/Testing	Included in Project Costs	Included in Project Costs	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in O&M
Land (note 6)	Included in Project Costs	Included in Project Costs	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included
Permanent Plant Equipment and Furnishings	Included	Included	Included	Included	Included	Included	Included	Included	Included in Project Cost
Builders Risk Insurance (0.45% of Project Cost)	$3.7	$9.7	$7.3	$4.0	$5.4	$3.4	$5.0	$5.7	$4.1
Owner's Contingency (5% of Total Project Cost)	$40.9	$107.8	$88.9	$49.0	$65.8	$41.5	$60.6	$69.2	$46.3
Total Screening Level Project Costs, 2020 MM$	**$977**	**$2,575**	**$1,874**	**$1,034**	**$1,387**	**$876**	**$1,277**	**$1,460**	**$977**
EPC Project Costs, 2020 $/kWh	**$214**	**$447**	**$217**	**$224**	**$251**	**$422**	**$277**	**$264**	**$265**
Total Screening Level Project Costs, 2020 $/kWh	**$257**	**$536**	**$250**	**$259**	**$289**	**$487**	**$319**	**$304**	**$287**
Demolition Costs (end of life cycle) 2020$/kWh (note 10)	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
O&M Cost, 2020 MM$/yr									
Fixed O&M Cost, 2020 MM$/yr	$5	$15	$12	$14	$12	$16	$14	$12	$11.4
Variable O&M Cost, 2020 $/MWh	$0	$0	$0.37	$0.37	$0.37	$0.37	$0.37	$0.37	$0

PROJECT TYPE	ADIABATIC CAES								
BASE PLANT DESCRIPTION	Hydrostor								
Nominal Output, MW	150	150	150	300	300	300	500	500	500
Nominal Output, MWh	600	1200	1800	1200	2400	3600	2000	4000	6000
Capacity Factor (%)	16%	32%	24%	16%	32%	24%	16%	32%	24%
Startup Time (Cold Start), minutes	5	5	5	5	5	5	5	5	5
Full Pumping to Full Gen, minutes	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Transition Time from Charging to Discharging, minutes	10	10	10	10	10	10	10	10	10
Availability Factor, %	95%	95%	95%	95%	95%	95%	95%	95%	95%
Technology Rating	Developing	Developing	Developing	Developing	Developing	Developing	Developing	Developing	Developing
Life Cycle, yrs	50+	50+	50+	50+	50+	50+	50+	50+	50+
Permitting & Construction Schedule, year (note 1)	2.5	2.5	2.5	2.5	2.5	3.0	3.0	3.5	3.5
ESTIMATED PERFORMANCE									
Base Load Performance @ (Annual Average)									
Net Plant Output, kW	150,000	150,000	150,000	300,000	300,000	300,000	500,000	500,000	500,000
Total Plant Storage, kWh (note 2)	600,000	1,200,000	1,800,000	1,200,000	2,400,000	3,600,000	2,000,000	4,000,000	6,000,000
Time for Full Discharge, hours	4	8	12	4	8	12	4	8	12
Time for Full Charge, hrs	7	13	20	7	13	20	7	13	20
Compression Power, MW (note 11)	90	90	90	180	180	180	300	300	300
Round-Trip Efficiency (%) (note 3)	60%	60%	60%	60%	60%	60%	60%	60%	60%
ESTIMATED CAPITAL AND O&M COSTS (Note 8)									
EPC Project Capital Costs, 2020 MM$ (w/o Owner's Costs)	**$235**	**$261**	**$290**	**$374**	**$402**	**$439**	**$572**	**$644**	**$700**
Owner's Costs, 2020 MM$	**$39**	**$46**	**$53**	**$63**	**$73**	**$84**	**$98**	**$118**	**$135**
Owner's Project Development	Included	Included	Included	Included	Included	Included	Included	Included	Included
Owner's Engineer	Included	Included	Included	Included	Included	Included	Included	Included	Included
Owner's Project Management	Included	Included	Included	Included	Included	Included	Included	Included	Included
Owner's Legal Costs	Included	Included	Included	Included	Included	Included	Included	Included	Included
Permitting and Licensing Fees	Included	Included	Included	Included	Included	Included	Included	Included	Included
Generation Switchyard (note 4)	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost
Transmission to Interconnection Point (note 4)	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost
Training/Testing	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost
Land (note 6)	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost
Permanent Plant Equipment and Furnishings	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost
Builders Risk Insurance (0.45% of Project Cost)	$1	$1	$1	$2	$2	$2	$3	$3	$3
Owner's Contingency (5% of Total Project Cost)	$11.8	$13.1	$14.6	$18.8	$20.2	$22.0	$28.7	$32.3	$35.2
Total Screening Level Project Costs, 2020 MM$	**$274**	**$307**	**$343**	**$437**	**$475**	**$523**	**$670**	**$762**	**$835**
EPC Project Costs, 2020 $/kWh	**$392**	**$218**	**$161**	**$312**	**$168**	**$122**	**$286**	**$161**	**$117**
Total Screening Level Project Costs, 2020 $/kWh	**$457**	**$256**	**$191**	**$364**	**$198**	**$145**	**$335**	**$191**	**$139**
Demolition Costs (end of life cycle) 2020$/kWh (note 10)	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
O&M Cost, 2020 MM$/yr									
Fixed O&M Cost, 2020 MM$/yr	$1.9	$1.9	$1.9	$2.8	$2.8	$2.8	$3.3	$3.3	$3.3
Variable O&M Cost, 2020 $/MWh	$6.50	$6.50	$6.50	$6.50	$6.50	$6.50	$6.50	$6.50	$6.50

PROJECT TYPE	Li-Ion Battery					Flow Battery			
BASE PLANT DESCRIPTION									
Nominal Output, MW	1	1	1	1	50	1	1	1	20
Nominal Output, MWh	0.5	1	4	8	200	1	4	8	160
Capacity Factor (%)	2%	4%	16%	32%	16%	4%	16%	32%	32%
Startup Time (Cold Start), minutes	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Full Pumping to Full Gen, minutes	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Transition Time from Charging to Discharging, minutes	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Availability Factor, %	97%	97%	97%	97%	97%	97%	97%	97%	97%
Technology Rating	Mature	Mature	Mature	Mature	Mature	Commercial	Commercial	Commercial	Commercial
Life Cycle, yrs	20	20	20	20	20	20	20	20	20
Permitting & Construction Schedule, year (note 1)	1.5	1.5	1.5	1.5	2	1.5	1.5	1.5	2
ESTIMATED PERFORMANCE									
Base Load Performance @ (Annual Average)									
Net Plant Output, kW	1,000	1,000	1,000	1,000	50,000	1,000	1,000	1,000	20,000
Total Plant Storage, kWh (note 2)	500	1,000	4,000	8,000	200,000	1,000	4,000	8,000	160,000
Time for Full Discharge, hours	0.5	1	4	8	4	1	4	8	8
Time for Full Charge, hrs	0.6	1.2	4.6	9.2	4.6	1.3	5.2	10.4	10.4
Compression Power, MW (note 11)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Round-Trip Efficiency (%) (note 3)	85%	85%	85%	85%	85%	70%	70%	70%	70%
ESTIMATED CAPITAL AND O&M COSTS (Note 8)									
EPC Project Capital Costs, 2020 MM$ (w/o Owner's Costs)	**$1.1**	**$1.2**	**$2.2**	**$3.5**	**$68.0**	**$3.6**	**$3.9**	**$5.9**	**$70.0**
Owner's Costs, 2020 MM$	**$0.8**	**$0.8**	**$0.8**	**$0.9**	**$13.7**	**$0.9**	**$0.9**	**$1.0**	**$13.8**
Owner's Project Development	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
Owner's Engineer	$0.1	$0.1	$0.1	$0.1	$0.2	$0.1	$0.1	$0.1	$0.2
Owner's Project Management	$0.1	$0.1	$0.1	$0.1	$0.2	$0.1	$0.1	$0.1	$0.2
Owner's Legal Costs	$0.1	$0.1	$0.1	$0.1	$0.5	$0.1	$0.1	$0.1	$0.5
Permitting and Licensing Fees	$0.1	$0.1	$0.1	$0.1	$0.3	$0.1	$0.1	$0.1	$0.3
Generation Switchyard (note 4)	$0.1	$0.1	$0.1	$0.1	$4.6	$0.1	$0.1	$0.1	$4.6
Transmission to Interconnection Point (note 4)	N/A	N/A	N/A	N/A	$3.5	N/A	N/A	N/A	$3.5
Training/Testing	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
Land (note 6)	Assumes Co-located	Assumes Co-located	Assumes Co-located	Assumes Co-located	Assumes Co-located	Assumes Co-located	Assumes Co-located	Assumes Co-located	Assumes Co-located
Permanent Plant Equipment and Furnishings	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Builders Risk Insurance (0.45% of Project Cost)	$0.00	$0.01	$0.01	$0.02	$0.31	$0.02	$0.02	$0.03	$0.32
Owner's Contingency (5% of Total Project Cost)	$0.1	$0.1	$0.1	$0.2	$3.9	$0.2	$0.2	$0.3	$4.0
Total Screening Level Project Costs, 2020 MM$	**$1.9**	**$2.0**	**$3.0**	**$4.4**	**$82**	**$4**	**$5**	**$7**	**$84**
EPC Project Costs, 2020 $/kWh	**$2,200**	**$1,200**	**$550**	**$438**	**$340**	**$3,600**	**$975**	**$738**	**$438**
Total Screening Level Project Costs, 2020 $/kWh	**$3,706**	**$1,959**	**$753**	**$548**	**$408**	**$4,490**	**$1,202**	**$864**	**$524**
Demolition Costs (end of life cycle) 2020$/kWh (note 10)	**$110**	**$110**	**$110**	**$110**	**$110**	**N/A**	**N/A**	**N/A**	**N/A**
O&M Cost, 2020 MM$/yr									
Fixed O&M Cost, 2020 MM$/yr	$0.04	$0.05	$0.07	$0.10	$1.38	$0.013	$0.013	$0.027	$0.61
Variable O&M Cost, 2020 $/MWh	Included in FOM	Included in FOM	Included in FOM	Included in FOM	Indluded in FOM	Included in FOM	Included in FOM	Included in FOM	Indluded in FOM

Notes
Note 1. Permitting & Construction Schedule is based on earliest COD date for some of the pumped hydro options
Note 2. CAES storage is based on full charge. Typical operation is to not fully discharge, but rather to discharge only a portion of the capacity to maintain cavern pressure.
Note 3. Round trip efficiency for CAES is based on the electric energy input to compress air plus the energy in the gas input compared to the electrical output.
Note 4. 1MW battery options (Li-Ion and Flow) assume interconnection at distribution voltage and therefore excludes GSU and switchyard. Larger options include GSU and switchyard costs as well as a standalone transmission cost. Also assumes co-located with existing asset and therefore excludes land costs.
Note 5. Battery O&M assumes the site is remotely controlled and that batteries cycle once per day. Capital costs assume the system is slightly oversized initially to accommodate normal degradation at the start of the project life, and then degradation supplement cost throughout the project life. O&M accounts for the parasitic power draw of the system, including HVAC and efficiency losses.
Note 6. Pumped Hydro O&M excludes major maintenance cost items, like generator rewinds, that are viewed as end of life repairs to extend the intended life of the asset.
Note 7. Battery capacity factor and annual O&M is based on one full cycle per day.
Note 8. EPC and Owner's Cost estimates exclude AFUDC, Sales Tax, Insurance and Property Tax During Construction
Note 9. Compression Capacity Ratio is defined as the relationship of the MWh of charging to the MWh of generation.
Note 10. Demolition costs are not shown for longer life cycle storage options (pumped hydro, CAES, and flow batteries). Li-Ion storage includes the cost to recycle the modules but does not include any resale of raw materials.
Note 11. Compressors can be sized to meet most charging duration requirments. A representative size has been chosen for the options shown.

PACIFICORP RENEWABLE TECHNOLOGY ASSESSMENT SUMMARY TABLE
SOLAR GENERATION

PROJECT TYPE				
PROJECT LOCATION	**Lakeview, OR**		**Milford, UT**	
BASE PLANT DESCRIPTION	**100 MW**	**200 MW**	**100 MW**	**200 MW**
Nominal Output, MW	100	200	100	200
Annualized Energy Production, MWh (Yr 1)	242,000	484,000	264,900	529,700
AC Capacity Factor at POI (%) (Note 1)	27.6%	27.6%	30.2%	30.2%
Availability Factor, % (Note 2)	99%	99%	99%	99%
Assumed Land Use, Acres	800	1600	800	1600
PV Inverter Loading Ratio (DC/AC)	1.30	1.30	1.30	1.30
PV Degradation, %/yr (Note 3)	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	100,000	200,000	100,000	200,000
ESTIMATED CAPITAL AND O&M COSTS (Note 7)				
EPC Project Capital Costs, 2020 MM$ (w/o Owner's Costs)	**$113**	**$222**	**$111**	**$216**
Modules	$48	$91	$48	$91
Racking w/ Piles	$16	$31	$16	$31
Inverter & MV Transformer	$4	$8	$4	$8
Labor, Materials, and BOP Equiment	$29	$59	$27	$53
Project Indirects, Fee, and Contingency	$16	$33	$16	$33
Owner's Costs, 2020 MM$	**$24**	**$31**	**$24**	**$31**
Owner's Project Development	$0.3	$0.3	$0.3	$0.3
Owner's Project Management	$0.1	$0.1	$0.1	$0.1
Owner's Legal Costs	$0.3	$0.3	$0.3	$0.3
Permitting and Licensing Fees	$0.5	$0.6	$0.5	$0.6
Interconnection Switchyard (Note 5)	$2.0	$2.0	$2.0	$2.0
Transmission Interconnection (Note 8)	$3.5	$3.5	$3.5	$3.5
Transmission Interconnection Application and Upgrades (Note 9)	$9.8	$9.8	$9.8	$9.8
Land (Note 4)	$0.0	$0.0	$0.0	$0.0
Operating Spare Parts	$0.8	$1.6	$0.8	$1.6
Builders Risk Insurance (0.45% of Project Cost)	$0.5	$1.0	$0.5	$1.0
Owner's Contingency	$6.5	$12.1	$6.4	$11.8
Total Screening Level Project Costs, 2020 MM$	**$137**	**$253**	**$135**	**$247**
EPC Project Costs, 2020 $/kW	**$1,130**	**$1,110**	**$1,110**	**$1,080**
Total Screening Level Project Costs, 2020 $/kW	**$1,372**	**$1,266**	**$1,351**	**$1,234**
Demolition Costs (end of life cycle) 2020$/kW	**$35**	**$35**	**$35**	**$35**
O&M Cost, 2020 MM$/yr	**$1.7**	**$3.2**	**$1.9**	**$3.5**
Third Party LTSA, 2020$MM/Yr	$0.7	$1.3	$0.7	$1.3
BOP and Other Cost, 2020$MM/Yr	$0.2	$0.3	$0.2	$0.3
Land Lease Allowance, 2020$MM/Yr	$0.4	$0.8	$0.6	$1.1
Capital Replacement Allowance, 2020$/MWh (Notes 3-5)	$0.4	$0.8	$0.4	$0.8
O&M Cost, 2020 $/kWac-yr	**$16.20**	**$16.10**	**$17.60**	**$17.60**
Co-Located Energy Storage - 4 hr Capacity				
Add-On Costs				
Capital Costs, 2020 MM$	$70	$133	$68	$130
Owner's Costs, 2020 MM$	$6.9	$10.3	$6.8	$10.1
Incremental O&M Cost, 2020 MM$/Yr	$1.38	$2.57	$1.38	$2.57
Co-Located Energy Storage - 4 hr Capacity + 200MW Wind				
Add-On Costs				
Capital Costs, 2020 MM$	N/A	$365	N/A	$361
Owner's Costs, 2020 MM$	N/A	$34	N/A	$33
Incremental O&M Cost, 2020 MM$/Yr	N/A	$13.37	N/A	$12.77

Notes
Note 1. Solar capacity factor accounts for typical losses. 100 and 200 MW options have AC capacity overbuilt for high voltage losses.
Note 2. Availability estimates are based on vendor correspondence and industry publications.
Note 3. PV degradation based on typical warranty information for polycrystalline products. Assuming factory recommended maintenance is performed, PV performance is estimated to degrade ~2% in the first year and 0.5% each
Note 4. PV projects assume that land is leased and therefore land costs are included in O&M, not capital costs. Assumes eight acres per MW for tracking.
Note 5. Solar project substation included in EPC cost. Interconnection switchyard assumes additional position on existing ring bus.
Note 6. Oregon cost estimates assume union labor.
Note 7. EPC and Owner's Cost estimates exclude AFUDC, Sales Tax, Insurance and Property Tax During Construction
Note 8. Transmission interconnect allowance assumes 3 miles of transmission line at 161 kV. Land costs are excluded.
Note 9. Transmission interconnect application costs and upgrade costs are representative only. These costs can vary greatly depending on the site location and existing infrastructure.

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	**200 MW**	**200 MW**	**200 MW**	**200 MW**	**200 MW**
Nominal Output, MW	200	200	200	200	200
Number of Turbines	50 x 4 MW	50 x 4 MW	50 x 4 MW	50 x 4 MW	50 x 4 MW
Capacity Factor (Note 1)	43.0%	43.0%	36.1%	48.6%	43.0%
Availability Factor, % (Note 2)	95%	95%	95%	95%	95%
Assumed Land Use, Acres	56	56	56	56	56
Technology Rating	Mature	Mature	Mature	Mature	Mature
Permitting & Construction Schedule, year	2.5	2.5	2.5	2.5	2.5
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 (Note 6)					
Project Capital Costs, 2020 MM$ (w/o Owner's Costs)	**$231**	**$232**	**$231**	**$231**	**$232**
Wind Turbine Generators	$155	$156	$155	$155	$156
Roads	$5	$5	$5	$5	$5
O&M Building	$2	$2	$2	$2	$2
Collection System	$8	$8	$8	$8	$8
Other BOP, Materials, Labor, Indirects	$61	$61	$61	$61	$61
Owner's Costs, 2020 MM$	**$73**	**$73**	**$72**	**$72**	**$73**
Project Development (Note 3)	$24.4	$24.4	$23.4	$23.4	$24.4
Wind Resource Assessment	$1.0	$1.0	$1.0	$1.0	$1.0
Land Control	$2.4	$2.4	$2.4	$2.4	$2.4
Permitting and Licensing Fees	$3.2	$3.2	$3.2	$3.2	$3.2
Generation Switchyard	$2.0	$2.0	$2.0	$2.0	$2.0
Transmission Interconnection (Note 7)	$3.5	$3.5	$3.5	$3.5	$3.5
Transmission Interconnection Application and Upgrades (Note 8)	$9.8	$9.8	$9.8	$9.8	$9.8
Land (Note 4)	$0.0	$0.0	$0.0	$0.0	$0.0
Operating Spare Parts	Included in O&M	Included in O&M	Included in O&M	Included in O&M	Included in O&M
Temporary facilities and Construction Utilities	$12.0	$12.0	$12.0	$12.0	$12.0
Builders Risk Insurance (0.45% of Project Cost)	Included in Project Costs	Included in Project Costs	Included in Project Costs	Included in Project Costs	Included in Project Costs
Owner's Contingency (5% of Total Project Cost)	$14.5	$14.5	$14.4	$14.4	$14.5
Total Screening Level Project Costs, 2020 MM$	**$304**	**$305**	**$303**	**$303**	**$305**
EPC Project Costs, 2020 $/kW	**$1,155**	**$1,160**	**$1,155**	**$1,155**	**$1,160**
Total Screening Level Project Costs, 2020 $/kW	**$1,519**	**$1,524**	**$1,513**	**$1,513**	**$1,524**
Demolition Costs (end of life cycle) 2020$/kW	**$13**	**$13**	**$13**	**$13**	**$13**
O&M Cost, 2020 MM$/yr	$10.6	$10.8	$10.2	$9.6	$10.8
O&M Cost, 2020 $/kW-yr	$53.0	$54.0	$51.0	$48.0	$54.0
Co-Located Energy Storage - 4 hr Capacity					
Add-On Costs					
Capital Costs, 2020 MM$	$130	$133	$130	$130	$133
Owner's Costs, 2020 MM$	$11.2	$11.3	$11.2	$11.2	$11.3
Incremental O&M Cost, 2020 MM$/Yr	$2.57	$2.57	$2.57	$2.57	$2.57

Notes
Note 1. Wind capacity factor based on NREL 80 meter wind speed maps used to convert wind speeds to 105 meter hub height.
Note 2. Availability estimates are based on vendor correspondence and industry publications.
Note 3. Development costs include legal costs, developer costs prior to COD, Owner project management, engineering, and interconnect studies.
Note 4. Wind projects assume that land is leased and therefore land costs are included in O&M, not capital costs. Assumes one acre per turbine.
Note 5. Oregon and Washington cost estimates assume union labor.
Note 6. EPC and Owner's Cost estimates exclude AFUDC, Sales Tax, Insurance and Property Tax During Construction
Note 7. Transmission interconnect allowance assumes 3 miles of transmission line at 161 kV. Land costs are excluded.
Note 8. Transmission interconnect application and upgrade costs are representative only. These costs can vary greatly depending on the site location and existing infrastructure.

Grid-Connected System: Simulation parameters

Project : **Pacificorp20-LakeviewOR**

Geographical Site	**Lakeview**		Country	**United States**
Situation	Latitude	42.17° N	Longitude	-120.40° W
Time defined as	Legal Time	Time zone UT-8	Altitude	1441 m
	Albedo	0.20		
Meteo data:	**Lakeview**	NREL: TMY3 hourly DB (1991-2005) - TMY		

Simulation variant : **PC20_VC0_LakeviewOR_SAT**

Simulation date 30/06/20 10h33

Simulation parameters	System type	**Trackers single array, with backtracking**		
Tracking plane, tilted axis	Axis Tilt	0°	Axis azimuth	0°
Rotation Limitations	Minimum Phi	-60°	Maximum Phi	60°
	Tracking algorithm	Irradiance optimization		
Backtracking strategy	Nb. of trackers	100	Single array	
	Tracker Spacing	10.00 m	Collector width	4.26 m
Inactive band	Left	0.02 m	Right	0.02 m
Backtracking limit angle	Phi limits	+/- 79.9°	Ground Cov. Ratio (GCR)	42.6%
Models used	Transposition	Perez	Diffuse	Imported
			Circumsolar	separate
Horizon	Average Height	2.4°		
Near Shadings	Linear shadings			
User's needs :	Unlimited load (grid)			

PV Array Characteristics

PV module Si-poly	Model	**CS3W-400P HE**		
Custom parameters definition	Manufacturer	Canadian Solar Inc.		
Number of PV modules	In series	28 modules	In parallel	488 strings
Total number of PV modules	nb. modules	13664	Unit Nom. Power	400 Wp
Array global power	Nominal (STC)	**5466 kWp**	At operating cond.	4961 kWp (50°C)
Array operating characteristics (50°C)	U mpp	982 V	I mpp	5049 A
Total area	Module area	**30186 m²**	Cell area	27114 m²
Inverter	Model	**Solar Ware 840 - PVU-L0840ER(PRERELEASE)**		
Custom parameters definition	Manufacturer	TMEIC		
Characteristics	Unit Nom. Power	**840 kWac**	Oper. Voltage	915-1300 V
Inverter pack	Total power	**4200 kWac**	Pnom ratio	1.30
	Nb. of inverters	5 units		
Total	Total power	**4200 kWac**	Pnom ratio	1.30

PV Array loss factors

Array Soiling Losses			Loss Fraction	2.0 %
Thermal Loss factor	Uc (const)	25.0 W/m²K	Uv (wind)	1.2 W/m²K / m/s
Wiring Ohmic Loss	Global array res.	3.2 mΩ	Loss Fraction	1.5 % at STC
LID - Light Induced Degradation			Loss Fraction	2.0 %
Module Quality Loss			Loss Fraction	-0.5 %
Module mismatch losses			Loss Fraction	2.0 % at MPP
Strings Mismatch loss			Loss Fraction	0.10 %

Grid-Connected System: Simulation parameters

Incidence effect (IAM): User defined profile

10°	20°	30°	40°	50°	60°	70°	80°	90°
1.000	1.000	1.000	0.990	0.990	0.970	0.920	0.760	0.000

System loss factors

AC wire loss inverter to transfo	Inverter voltage	630 Vac tri		
	Wires: 3 x 4000 mm²	1 m	Loss Fraction	0.0 % at STC

MV transfo	Grid Voltage	34.5 kV		
One MV transfo				
Operating losses at STC	Iron loss (24/24 Connexion)	10.70 kW	Loss Fraction	0.2 % at STC
	Copper (resistive) loss	3 x 1.03 mΩ	Loss Fraction	1.4 % at STC

Grid-Connected System: Horizon definition

Project : **Pacificorp20-LakeviewOR**

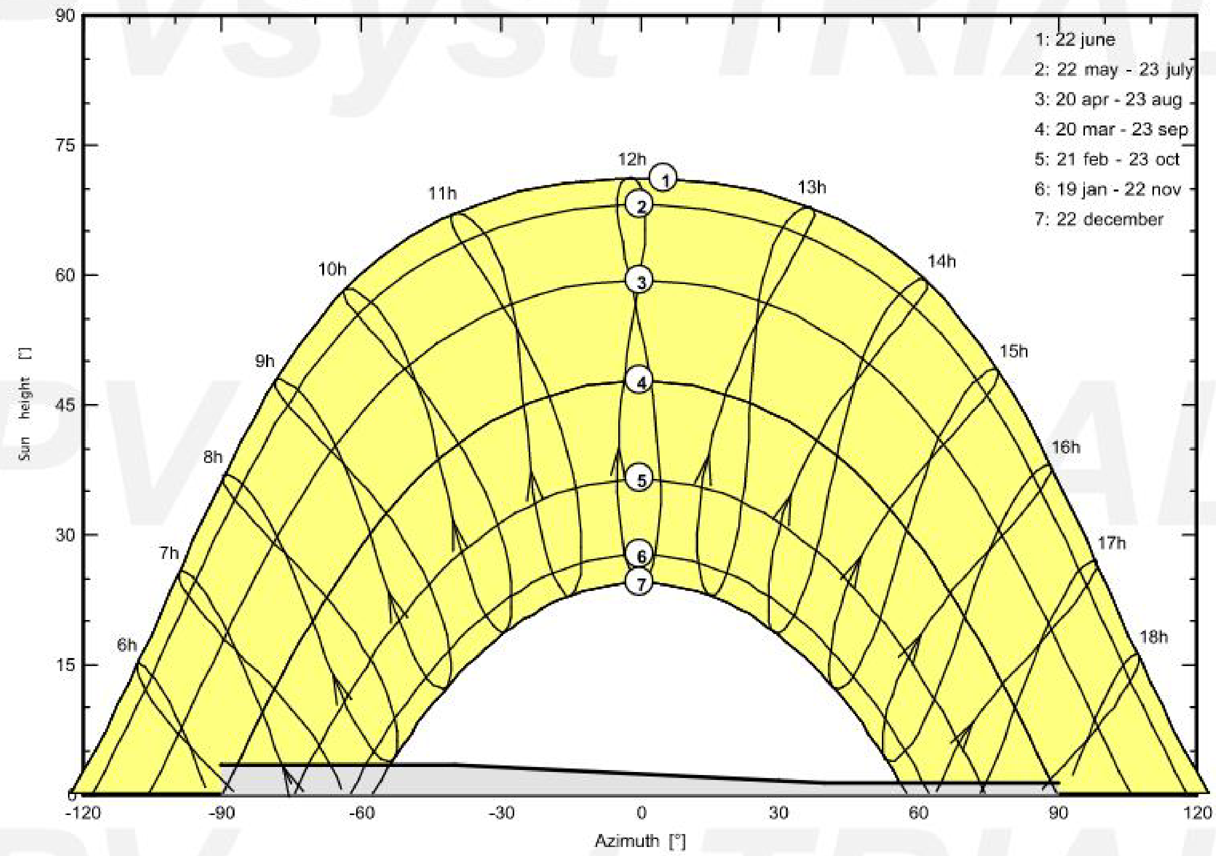
Simulation variant : **PC20_VC0_LakeviewOR_SAT**

Main system parameters	System type	**Trackers single array, with backtracking**		
Horizon	Average Height	2.4°		
Near Shadings	Linear shadings			
PV Field Orientation	tracking, tilted axis, Axis Tilt	0°	Axis azimuth	0°
PV modules	Model	CS3W-400P HE	Pnom	400 Wp
PV Array	Nb. of modules	13664	Pnom total	**5466 kWp**
Inverter	Solar Ware 840 - PVU-L0840ER(PRERELEASE)		Pnom	840 kW ac
Inverter pack	Nb. of units	5.0	Pnom total	**4200 kW ac**
User's needs	Unlimited load (grid)			

Horizon	Average Height	2.4°	Diffuse Factor	0.99
	Albedo Factor	100%	Albedo Fraction	0.96

Height [°]	3.4	3.4	1.4	1.4
Azimuth [°]	-90	-40	40	90

Horizon line at LakeviewOR_NSRDB



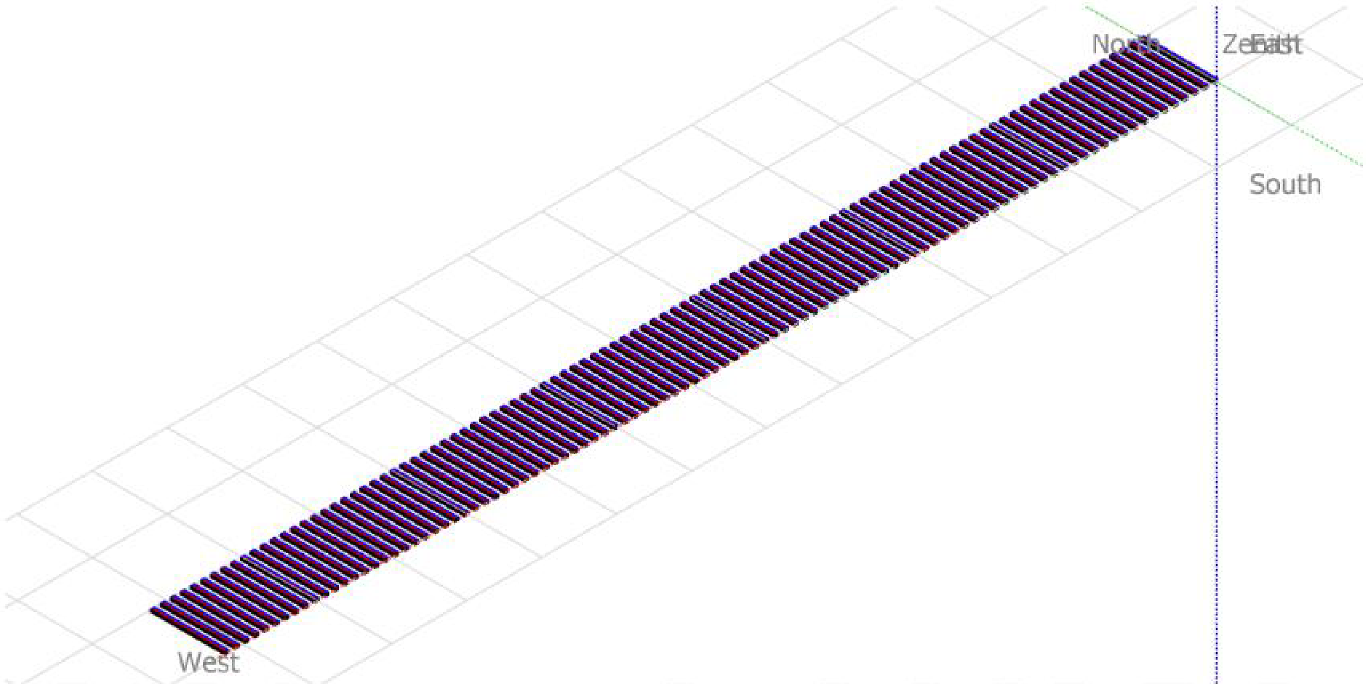
Grid-Connected System: Near shading definition

Project : **Pacificorp20-LakeviewOR**

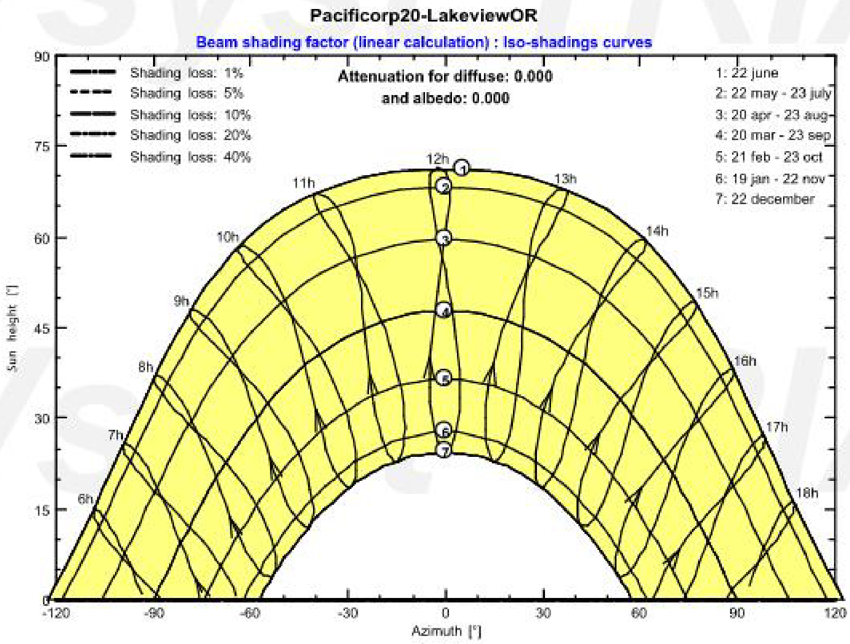
Simulation variant : **PC20_VC0_LakeviewOR_SAT**

Main system parameters	System type	**Trackers single array, with backtracking**		
Horizon	Average Height	2.4°		
Near Shadings	Linear shadings			
PV Field Orientation	tracking, tilted axis, Axis Tilt	0°	Axis azimuth	0°
PV modules	Model	CS3W-400P HE	Pnom	400 Wp
PV Array	Nb. of modules	13664	Pnom total	**5466 kWp**
Inverter	Solar Ware 840 - PVU-L0840ER(PRERELEASE)		Pnom	840 kW ac
Inverter pack	Nb. of units	5.0	Pnom total	**4200 kW ac**
User's needs	Unlimited load (grid)			

Perspective of the PV-field and surrounding shading scene



Iso-shadings diagram



Grid-Connected System: Main results

Project : **Pacificorp20-LakeviewOR**

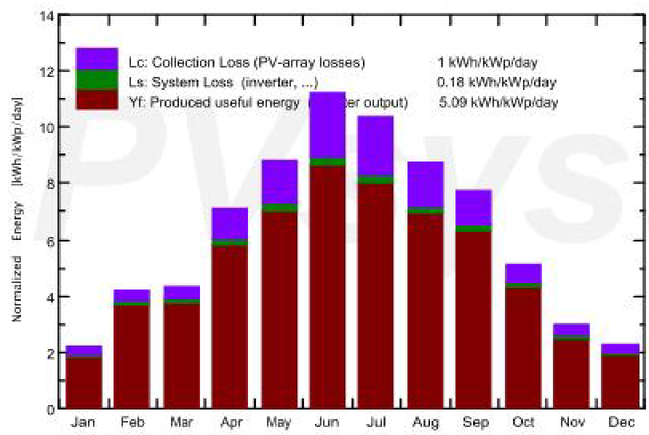
Simulation variant : **PC20_VC0_LakeviewOR_SAT**

Main system parameters	System type	**Trackers single array, with backtracking**		
Horizon	Average Height	2.4°		
Near Shadings	Linear shadings			
PV Field Orientation	tracking, tilted axis, Axis Tilt	0°	Axis azimuth	0°
PV modules	Model	CS3W-400P HE	Pnom	400 Wp
PV Array	Nb. of modules	13664	Pnom total	**5466 kWp**
Inverter	Solar Ware 840 - PVU-L0840ER(PRERELEASE)		Pnom	840 kW ac
Inverter pack	Nb. of units	5.0	Pnom total	**4200 kW ac**
User's needs	Unlimited load (grid)			

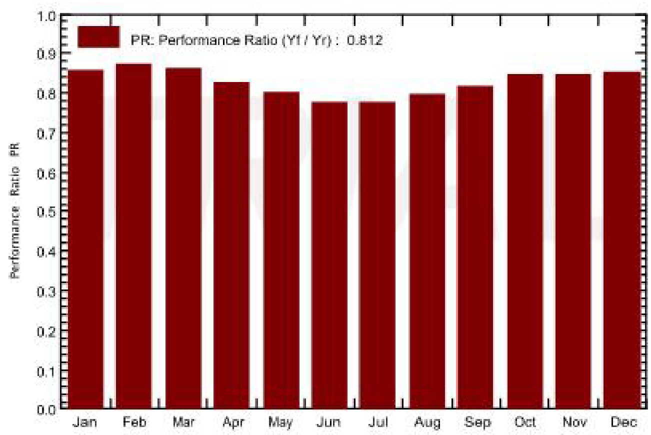
Main simulation results

System Production	**Produced Energy**	**10146 MWh/year**	Specific prod.	1856 kWh/kWp/year
	Performance Ratio PR	81.15 %		

Normalized productions (per installed kWp): Nominal power 5466 kWp



Performance Ratio PR



PC20_VC0_LakeviewOR_SAT

Balances and main results

	GlobHor kWh/m²	DiffHor kWh/m²	T_Amb °C	GlobInc kWh/m²	GlobEff kWh/m²	EArray MWh	E_Grid MWh	PR ratio
January	52.8	28.22	-1.22	67.9	62.0	334	317	0.854
February	85.1	27.99	-0.46	118.6	109.9	587	565	0.872
March	106.7	50.37	2.86	135.8	126.4	665	640	0.862
April	163.1	61.22	5.42	212.8	200.2	994	960	0.825
May	209.3	67.48	9.94	273.8	258.5	1235	1195	0.799
June	251.2	49.77	16.42	336.8	319.7	1471	1425	0.774
July	242.7	54.01	20.83	321.4	304.8	1404	1360	0.774
August	198.5	46.36	17.73	270.3	256.0	1215	1176	0.796
September	167.3	37.18	14.61	232.3	218.7	1069	1035	0.815
October	114.2	35.81	6.91	158.2	147.4	759	733	0.847
November	63.8	22.84	1.73	89.2	81.8	432	413	0.847
December	49.6	20.66	-0.87	70.4	64.1	344	328	0.851
Year	1704.3	501.91	7.87	2287.5	2149.6	10512	10146	0.812

Legends:

GlobHor	Global horizontal irradiation	GlobEff	Effective Global, corr. for IAM and shadings
DiffHor	Horizontal diffuse irradiation	EArray	Effective energy at the output of the array
T_Amb	T amb.	E_Grid	Energy injected into grid
GlobInc	Global incident in coll. plane	PR	Performance Ratio

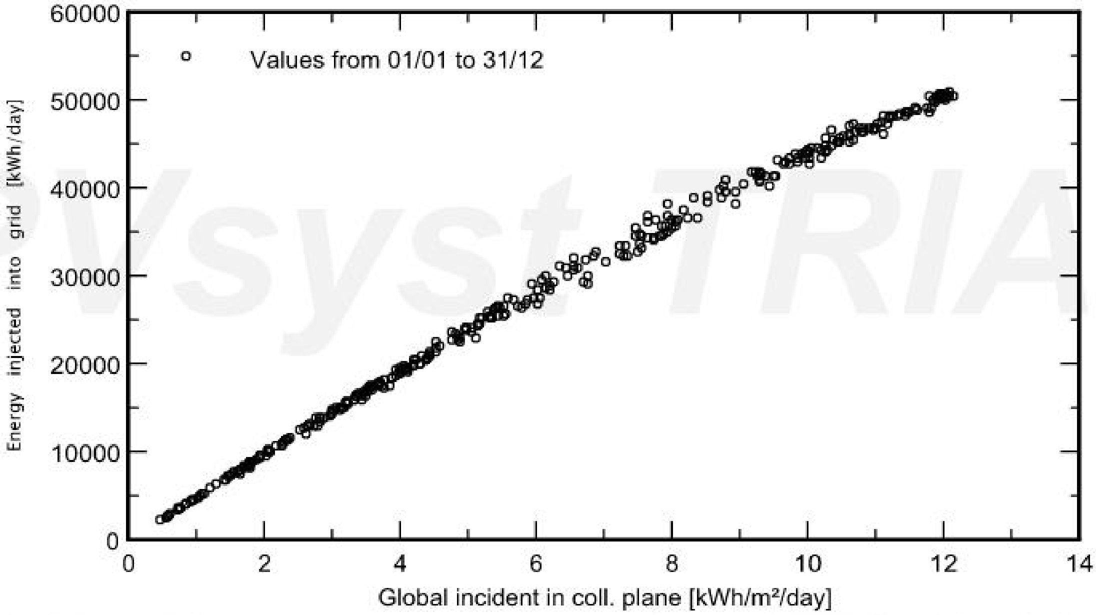
Grid-Connected System: Special graphs

Project : **Pacificorp20-LakeviewOR**

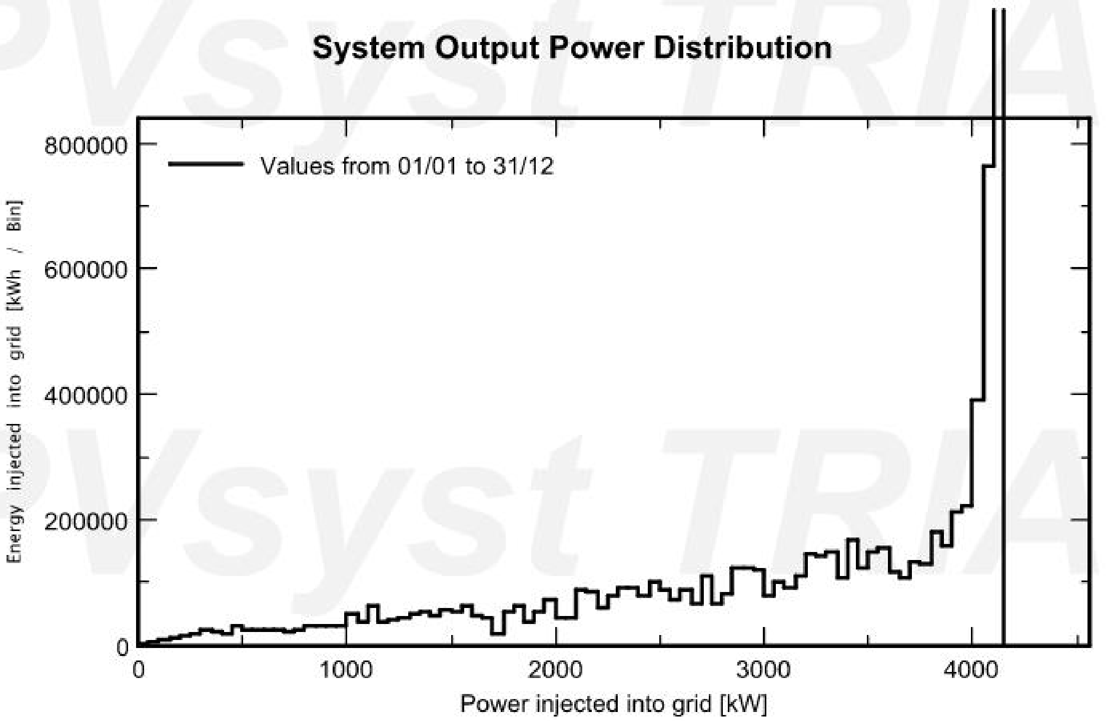
Simulation variant : **PC20_VC0_LakeviewOR_SAT**

Main system parameters	System type	**Trackers single array, with backtracking**		
Horizon	Average Height	2.4°		
Near Shadings	Linear shadings			
PV Field Orientation	tracking, tilted axis, Axis Tilt	0°	Axis azimuth	0°
PV modules	Model	CS3W-400P HE	Pnom	400 Wp
PV Array	Nb. of modules	13664	Pnom total	**5466 kWp**
Inverter	Solar Ware 840 - PVU-L0840ER(PRERELEASE)		Pnom	840 kW ac
Inverter pack	Nb. of units	5.0	Pnom total	**4200 kW ac**
User's needs	Unlimited load (grid)			

Daily Input/Output diagram



System Output Power Distribution



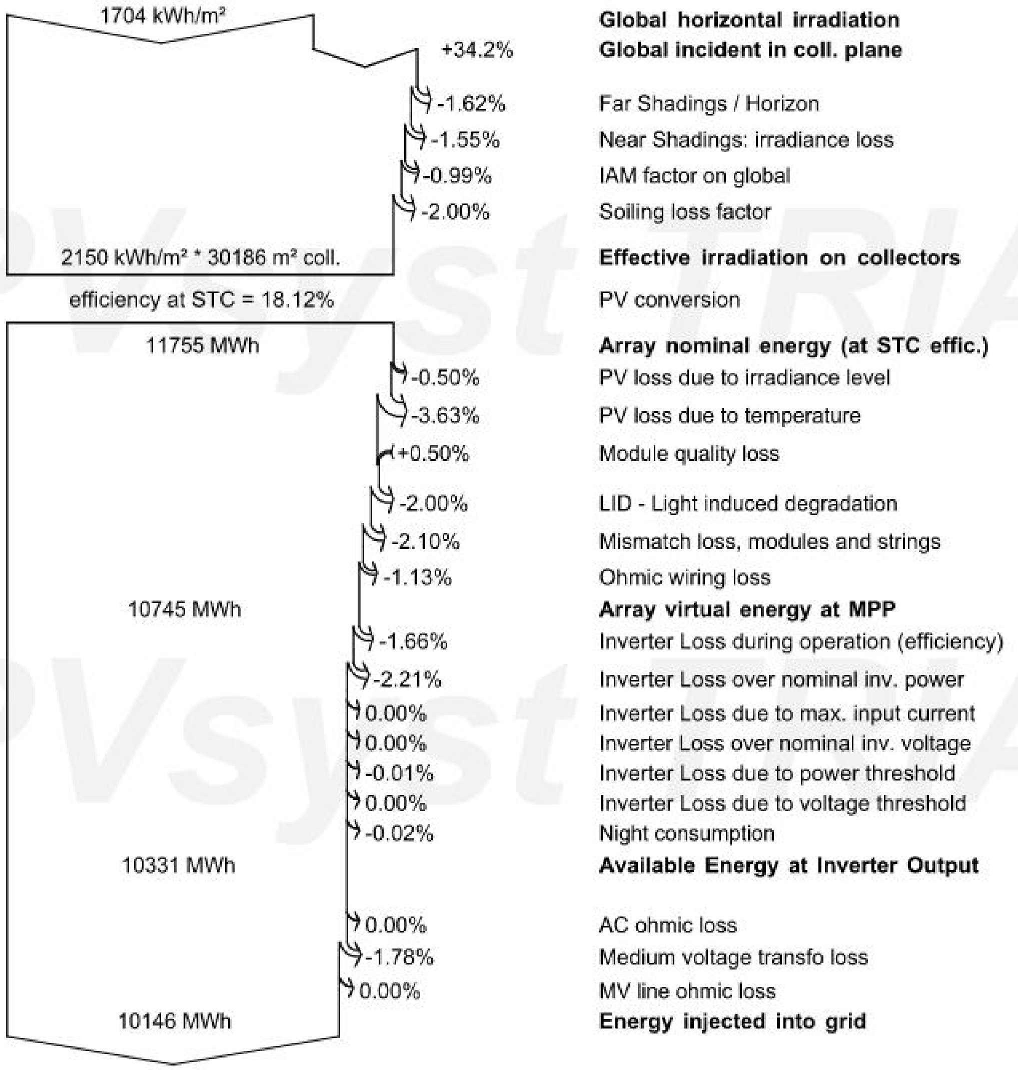
Grid-Connected System: Loss diagram

Project : **Pacificorp20-LakeviewOR**

Simulation variant : **PC20_VC0_LakeviewOR_SAT**

Main system parameters	System type	**Trackers single array, with backtracking**		
Horizon	Average Height	2.4°		
Near Shadings	Linear shadings			
PV Field Orientation	tracking, tilted axis, Axis Tilt	0°	Axis azimuth	0°
PV modules	Model	CS3W-400P HE	Pnom	400 Wp
PV Array	Nb. of modules	13664	Pnom total	**5466 kWp**
Inverter	Solar Ware 840 - PVU-L0840ER(PRERELEASE)		Pnom	840 kW ac
Inverter pack	Nb. of units	5.0	Pnom total	**4200 kW ac**
User's needs	Unlimited load (grid)			

Loss diagram over the whole year



Grid-Connected System: Simulation parameters

Project :	**Pacificorp20-MilfordUT**			
Geographical Site	**MilfordUT_NSRDB**		Country	**United States**
Situation	Latitude	38.41° N	Longitude	-113.02° W
Time defined as	Legal Time	Time zone UT-7	Altitude	0 m
	Albedo	0.20		
Meteo data:	**MilfordUT_NSRDB**	NREL: TMY3 hourly DB (1991-2005) - TMY		

Simulation variant :	**MilfordUT_SAT**			
	Simulation date	23/06/20 14h56		

Simulation parameters	System type	**Trackers single array, with backtracking**		
Tracking plane, tilted axis	Axis Tilt	0°	Axis azimuth	0°
Rotation Limitations	Minimum Phi	-60°	Maximum Phi	60°
	Tracking algorithm	Irradiance optimization		
Backtracking strategy	Nb. of trackers	100	Single array	
	Tracker Spacing	10.00 m	Collector width	4.26 m
Inactive band	Left	0.02 m	Right	0.02 m
Backtracking limit angle	Phi limits	+/- 79.9°	Ground Cov. Ratio (GCR)	42.6%
Models used	Transposition	Perez	Diffuse	Imported
			Circumsolar	separate
Horizon	Average Height	3.0°		
Near Shadings	Linear shadings			
User's needs :	Unlimited load (grid)			

PV Array Characteristics					
PV module	Si-poly	Model	**CS3W-400P HE**		
Custom parameters definition		Manufacturer	Canadian Solar Inc.		
Number of PV modules		In series	28 modules	In parallel	488 strings
Total number of PV modules		nb. modules	13664	Unit Nom. Power	400 Wp
Array global power		Nominal (STC)	**5466 kWp**	At operating cond.	4961 kWp (50°C)
Array operating characteristics (50°C)		U mpp	982 V	I mpp	5049 A
Total area		Module area	**30186 m²**	Cell area	27114 m²
Inverter		Model	**Solar Ware 840 - PVU-L0840ER(PRERELEASE)**		
Custom parameters definition		Manufacturer	TMEIC		
Characteristics		Unit Nom. Power	**840 kWac**	Oper. Voltage	915-1300 V
Inverter pack		Total power	**4200 kWac**	Pnom ratio	1.30
		Nb. of inverters	5 units		
Total		Total power	**4200 kWac**	Pnom ratio	1.30

PV Array loss factors				
Array Soiling Losses			Loss Fraction	2.0 %
Thermal Loss factor	Uc (const)	25.0 W/m²K	Uv (wind)	1.2 W/m²K / m/s
Wiring Ohmic Loss	Global array res.	3.2 mΩ	Loss Fraction	1.5 % at STC
LID - Light Induced Degradation			Loss Fraction	2.0 %
Module Quality Loss			Loss Fraction	-0.5 %
Module mismatch losses			Loss Fraction	2.0 % at MPP
Strings Mismatch loss			Loss Fraction	0.10 %

Grid-Connected System: Simulation parameters

Incidence effect (IAM): User defined profile

10°	20°	30°	40°	50°	60°	70°	80°	90°
1.000	1.000	1.000	0.990	0.990	0.970	0.920	0.760	0.000

System loss factors

AC wire loss inverter to transfo	Inverter voltage	630 Vac tri		
	Wires: 3 x 4000 mm²	1 m	Loss Fraction	0.0 % at STC

MV transfo	Grid Voltage	34.5 kV		
One MV transfo				
Operating losses at STC	Iron loss (24/24 Connexion)	10.73 kW	Loss Fraction	0.2 % at STC
	Copper (resistive) loss	3 x 1.03 mΩ	Loss Fraction	1.4 % at STC

Grid-Connected System: Horizon definition

Project : **Pacificorp20-MilfordUT**

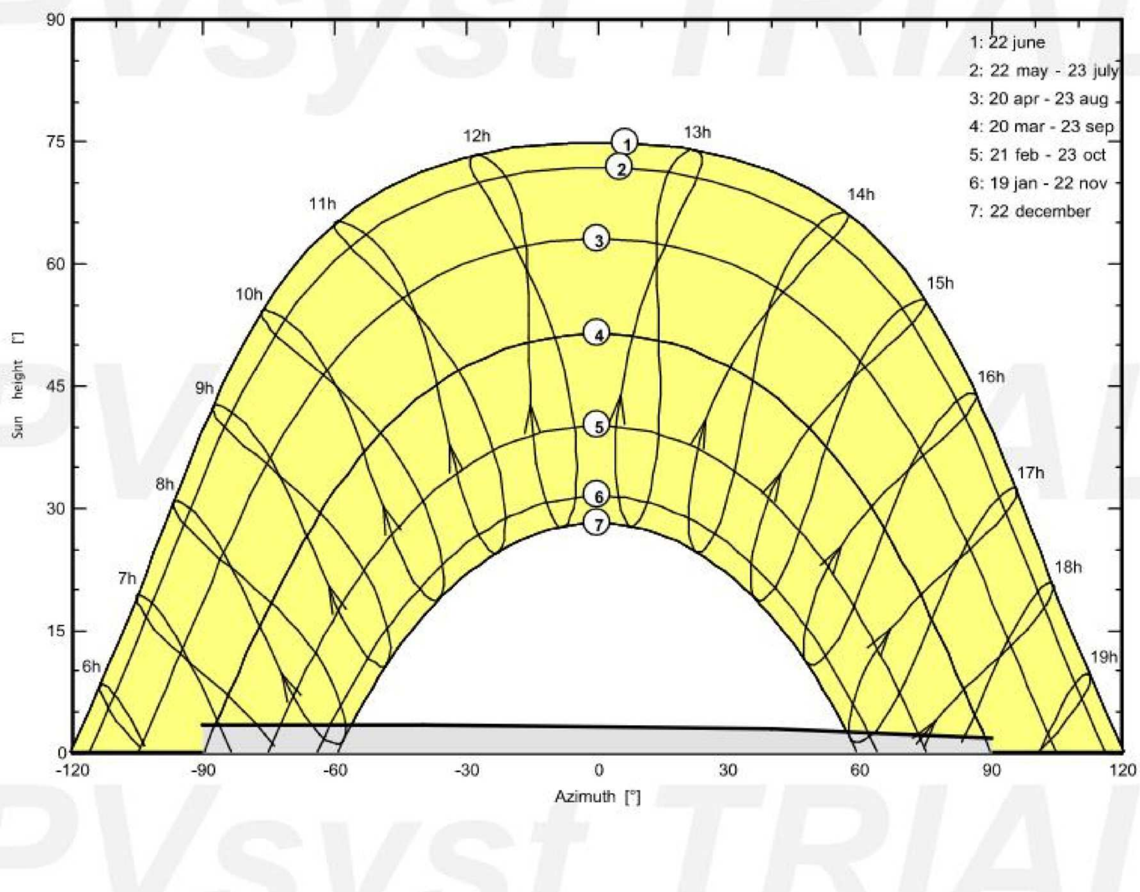
Simulation variant : **MilfordUT_SAT**

Main system parameters	System type	**Trackers single array, with backtracking**		
Horizon	Average Height	3.0°		
Near Shadings	Linear shadings			
PV Field Orientation	tracking, tilted axis, Axis Tilt	0°	Axis azimuth	0°
PV modules	Model	CS3W-400P HE	Pnom	400 Wp
PV Array	Nb. of modules	13664	Pnom total	**5466 kWp**
Inverter	Solar Ware 840 - PVU-L0840ER(PRERELEASE)		Pnom	840 kW ac
Inverter pack	Nb. of units	5.0	Pnom total	**4200 kW ac**
User's needs	Unlimited load (grid)			

Horizon	Average Height	3.0°	Diffuse Factor	0.98
	Albedo Factor	100%	Albedo Fraction	0.94

Height [°]	3.4	3.4	2.9	1.8
Azimuth [°]	-90	-40	40	90

Horizon line at MilfordUT_NSRDB



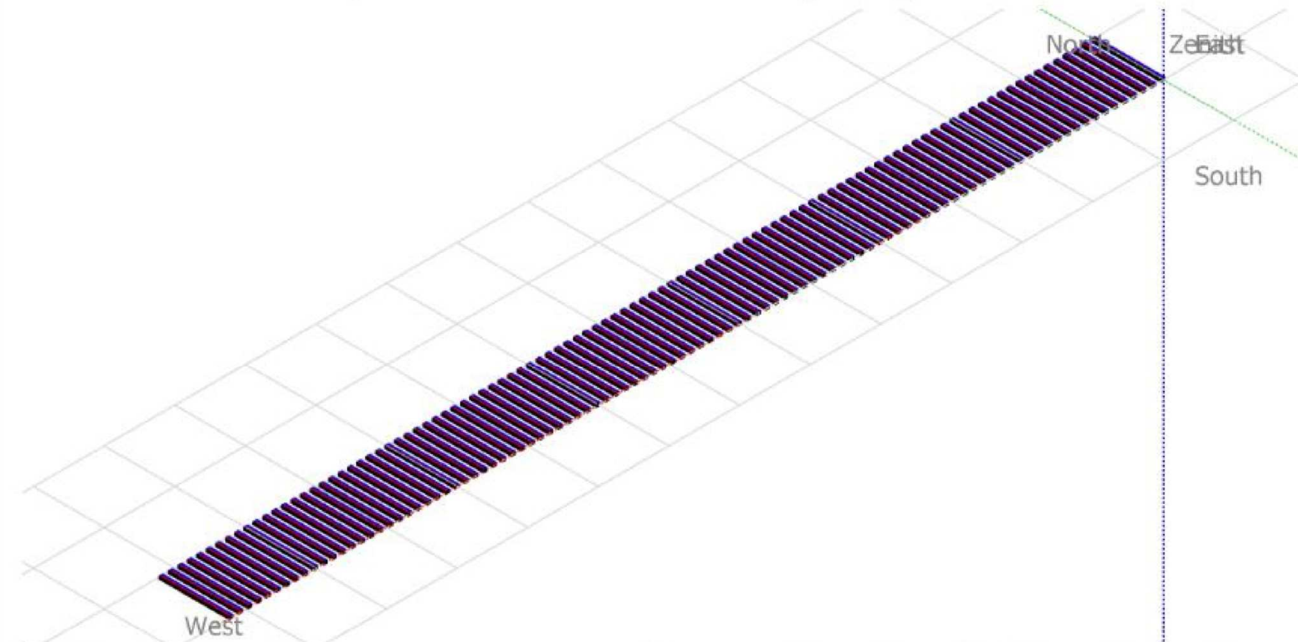
Grid-Connected System: Near shading definition

Project : **Pacificorp20-MilfordUT**

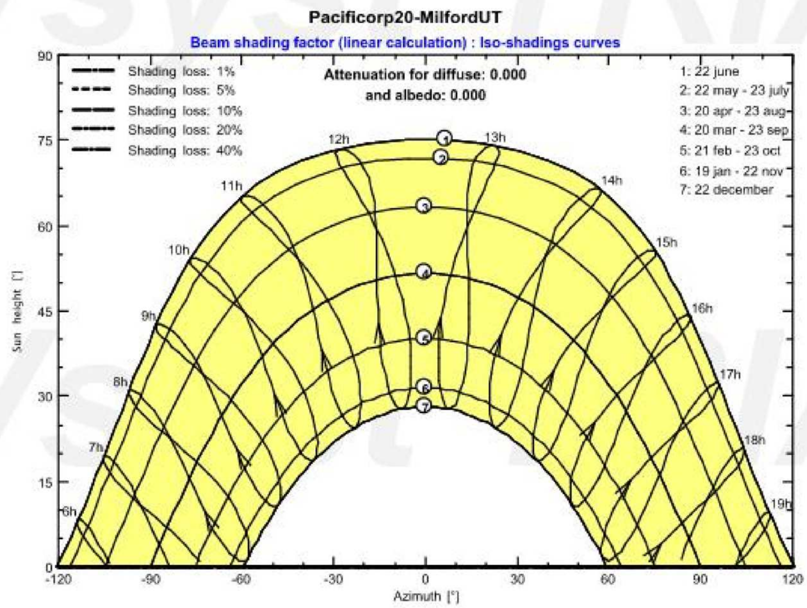
Simulation variant : **MilfordUT_SAT**

Main system parameters	System type	**Trackers single array, with backtracking**		
Horizon	Average Height	3.0°		
Near Shadings	Linear shadings			
PV Field Orientation	tracking, tilted axis, Axis Tilt	0°	Axis azimuth	0°
PV modules	Model	CS3W-400P HE	Pnom	400 Wp
PV Array	Nb. of modules	13664	Pnom total	**5466 kWp**
Inverter	Solar Ware 840 - PVU-L0840ER(PRERELEASE)		Pnom	840 kW ac
Inverter pack	Nb. of units	5.0	Pnom total	**4200 kW ac**
User's needs	Unlimited load (grid)			

Perspective of the PV-field and surrounding shading scene



Iso-shadings diagram



Grid-Connected System: Main results

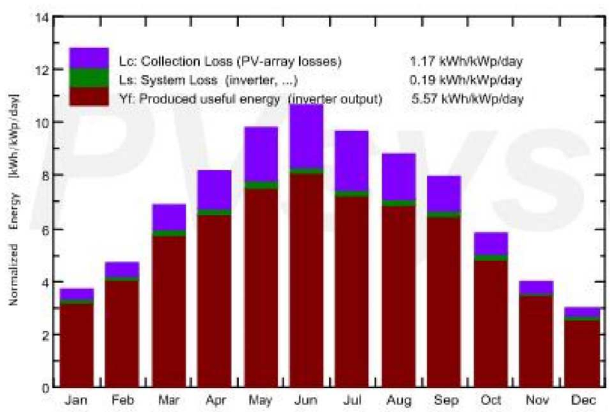
Project : **Pacificorp20-MilfordUT**

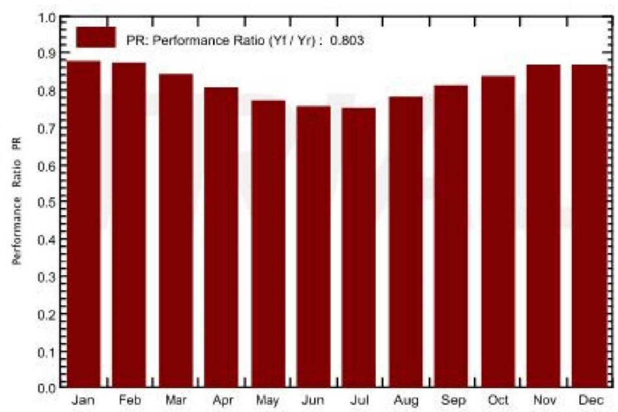
Simulation variant : **MilfordUT_SAT**

Main system parameters	System type	**Trackers single array, with backtracking**		
Horizon	Average Height	3.0°		
Near Shadings	Linear shadings			
PV Field Orientation	tracking, tilted axis, Axis Tilt	0°	Axis azimuth	0°
PV modules	Model	CS3W-400P HE	Pnom	400 Wp
PV Array	Nb. of modules	13664	Pnom total	**5466 kWp**
Inverter	Solar Ware 840 - PVU-L0840ER(PRERELEASE)		Pnom	840 kW ac
Inverter pack	Nb. of units	5.0	Pnom total	**4200 kW ac**
User's needs	Unlimited load (grid)			

Main simulation results

System Production	**Produced Energy**	**11113 MWh/year**	Specific prod.	2033 kWh/kWp/year
	Performance Ratio PR	80.32 %		





MilfordUT_SAT

Balances and main results

	GlobHor kWh/m²	**DiffHor** kWh/m²	**T_Amb** °C	**GlobInc** kWh/m²	**GlobEff** kWh/m²	**EArray** MWh	**E_Grid** MWh	**PR** ratio
January	83.0	25.95	-1.63	114.6	105.9	571	549	0.876
February	97.2	34.43	0.96	130.7	122.0	647	623	0.872
March	158.1	47.64	2.97	213.0	200.6	1014	980	0.841
April	188.5	62.38	7.14	244.2	231.0	1113	1076	0.806
May	233.1	62.75	15.67	303.5	288.3	1323	1281	0.772
June	243.9	56.57	19.11	320.3	304.5	1365	1322	0.755
July	230.2	57.42	23.97	299.1	284.3	1269	1229	0.752
August	207.6	52.71	23.16	274.0	260.1	1204	1166	0.778
September	175.2	38.23	15.35	238.3	225.7	1093	1057	0.812
October	132.0	32.68	11.70	180.3	168.9	851	822	0.835
November	86.8	26.42	1.58	120.3	111.6	591	568	0.865
December	67.8	23.58	-1.75	93.4	85.6	461	442	0.865
Year	1903.4	520.77	9.92	2531.7	2388.6	11502	11113	0.803

Legends:

GlobHor	Global horizontal irradiation	GlobEff	Effective Global, corr. for IAM and shadings
DiffHor	Horizontal diffuse irradiation	EArray	Effective energy at the output of the array
T_Amb	T amb.	E_Grid	Energy injected into grid
GlobInc	Global incident in coll. plane	PR	Performance Ratio

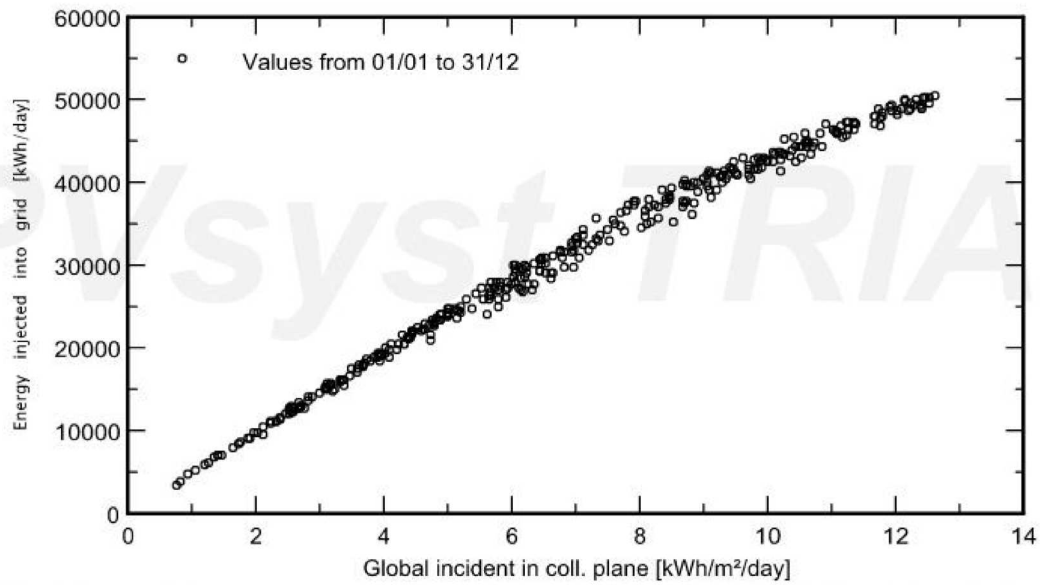
Grid-Connected System: Special graphs

Project : **Pacificorp20-MilfordUT**

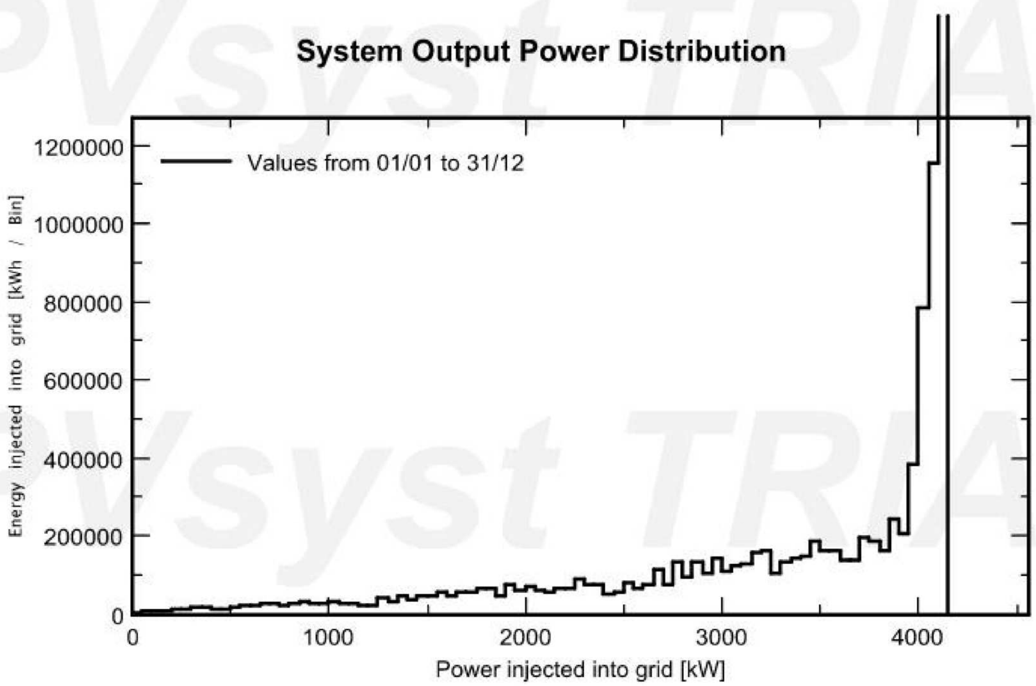
Simulation variant : **MilfordUT_SAT**

Main system parameters	System type	**Trackers single array, with backtracking**		
Horizon	Average Height	3.0°		
Near Shadings	Linear shadings			
PV Field Orientation	tracking, tilted axis, Axis Tilt	0°	Axis azimuth	0°
PV modules	Model	CS3W-400P HE	Pnom	400 Wp
PV Array	Nb. of modules	13664	Pnom total	**5466 kWp**
Inverter	Solar Ware 840 - PVU-L0840ER(PRERELEASE)		Pnom	840 kW ac
Inverter pack	Nb. of units	5.0	Pnom total	**4200 kW ac**
User's needs	Unlimited load (grid)			

Daily Input/Output diagram



System Output Power Distribution



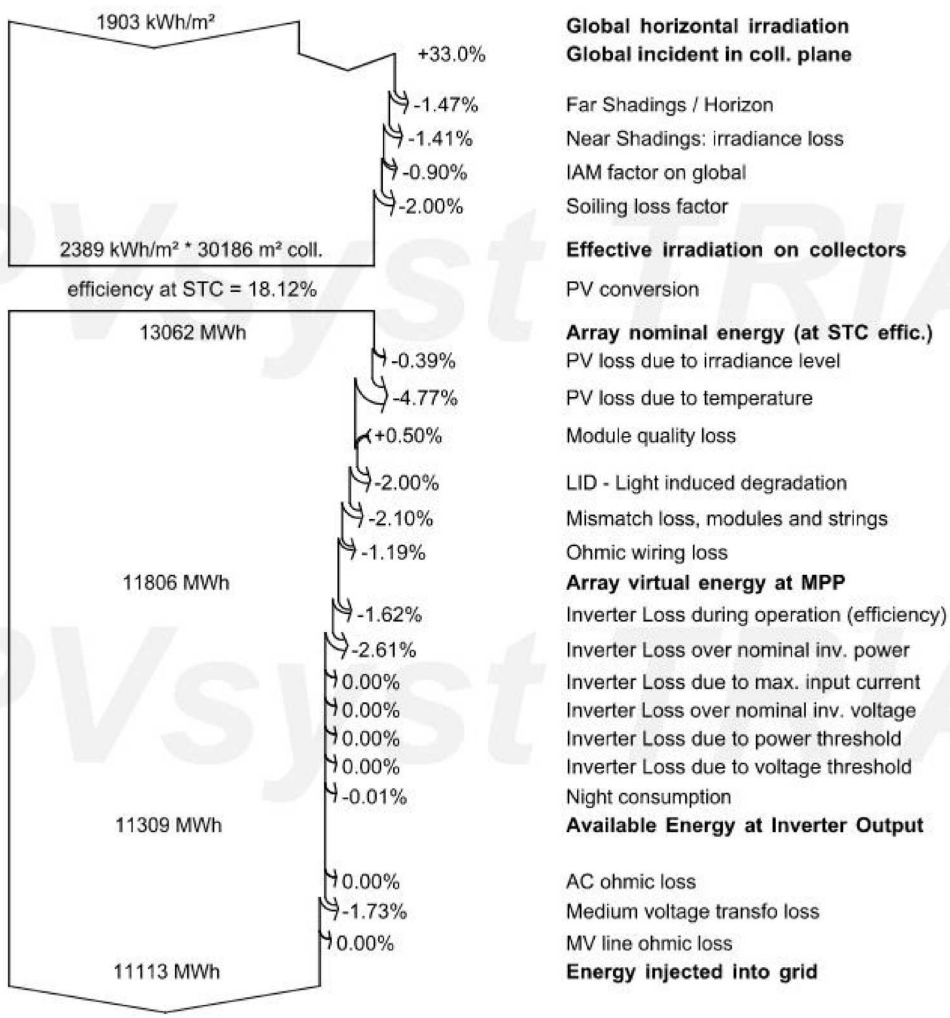
Grid-Connected System: Loss diagram

Project : **Pacificorp20-MilfordUT**

Simulation variant : **MilfordUT_SAT**

Main system parameters	System type	**Trackers single array, with backtracking**		
Horizon	Average Height	3.0°		
Near Shadings	Linear shadings			
PV Field Orientation	tracking, tilted axis, Axis Tilt	0°	Axis azimuth	0°
PV modules	Model	CS3W-400P HE	Pnom	400 Wp
PV Array	Nb. of modules	13664	Pnom total	**5466 kWp**
Inverter	Solar Ware 840 - PVU-L0840ER(PRERELEASE)		Pnom	840 kW ac
Inverter pack	Nb. of units	5.0	Pnom total	**4200 kW ac**
User's needs	Unlimited load (grid)			

Loss diagram over the whole year



BURNS & McDONNELL

Energy Production Summary

Burns & McDonnell, Energy Division

Project Name: **Pacificorp 2020 Renewables Technology Assessment**

Variant: VC0 Date: 26-Jun-20

Site Information	
City / State:	Lakeview, OR
Latitude (N):	42.17 °
Longitude (W):	-120.4 °
Altitude	1441 m
ASHRAE Cooling DB Temp.	32.2 °C
ASHRAE Extreme Mean Min. Temp.	-22.6 °C

Estimated Annual Energy Production	
P50 net production (yr-1)	241986.6 MWh
AC capacity factor - Inv Rating	27.62%
AC capacity factor - POI Rating	27.62%
DC capacity factor	21.23%
Specific Production	1860 kWh/kWp/yr
Performance Ratio PR	81.15%
Night time losses	-407.2 MWh
Plant Output Limitations	0.00%

Design Parameters	
System DC Voltage	1500 VDC
GCR	42.6 %
Row spacing	10 m
Mounting	Tracker
Tilt angle or rotation limits	60 °
Azimuth	0 °
Tracking strategy	TRUE
Availability	100.0 %
Degradation	0.5 %/yr

Facility Level Information	
Nameplate Capacity	**130.13 MWDC**
Number of modules	325333
Nameplate Capacity	**100.00 MWAC**
Number of arrays	24
Interconnection Limit	**100.00 MWAC**
Inteconnection Voltage	34.5 kV
DC/AC ratio - POI Rating	1.301

Array Level Information	
Module rating	400 W
# Modules per string	28
Strings in parallel	488
Total number of modules	13664
DC capacity	5466 kW
Inverter rating	4200 kW
DC/AC ratio - Inv Rating	1.301

Weather	
Source	TMY3
GHI	1704.3 kWh/m2
DHI	kWh/m2
Global POA	2287.5 kWh/m2
Average Temp.	7.87 °C
Average Temp. (Generation)	12.45 °C
Average Wind	3.33 m/s
Average Wind (Generation)	3.61 m/s

PVsyst Input Parameters	
Transposition model	Perez
Constant thermal loss factor (Uc)	25.0 W/m2-K
Wind loss factor (Uv)	1.2 W/m2-K/m/s
Soiling losses	2.2 %
Light induced degradation	2.0 %
DC wiring loss	1.5 %
Module quality loss	-0.4 %
Module mismatch loss	1.0 %
DC health loss	1.0 %

AC System Losses	
MV transformer no-load losses	0.00%
MV transformer full load losses	0.00%
MV collection system	1.30%
HV transformer no-load losses	0.07%
HV transformer full load losses	0.48%
HV line	0.05%
Auxiliary	0.01%

BURNS & McDONNELL

Energy Production Summary

Burns & McDonnell, Energy Division

Project Name: **Pacificorp 2020 Renewables Technology Assessment**

Variant: VC0 Date: 26-Jun-20

Site Information	
City / State:	Lakeview, OR
Latitude (N):	42.17 °
Longitude (W):	-120.4 °
Altitude	1441 m
ASHRAE Cooling DB Temp.	32.2 °C
ASHRAE Extreme Mean Min. Temp.	-22.6 °C

Estimated Annual Energy Production	
P50 net production (yr-1)	483973.1 MWh
AC capacity factor - Inv Rating	27.62%
AC capacity factor - POI Rating	27.62%
DC capacity factor	21.23%
Specific Production	1860 kWh/kWp/yr
Performance Ratio PR	81.15%
Night time losses	-814.4 MWh
Plant Output Limitations	0.00%

Design Parameters	
System DC Voltage	1500 VDC
GCR	42.6 %
Row spacing	10 m
Mounting	Tracker
Tilt angle or rotation limits	60 °
Azimuth	0 °
Tracking strategy	TRUE
Availability	100.0 %
Degradation	0.5 %/yr

Facility Level Information	
Nameplate Capacity	**260.27 MWDC**
Number of modules	650667
Nameplate Capacity	**200.00 MWAC**
Number of arrays	48
Interconnection Limit	**200.00 MWAC**
Inteconnection Voltage	34.5 kV
DC/AC ratio - POI Rating	1.301

Array Level Information	
Module rating	400 W
# Modules per string	28
Strings in parallel	488
Total number of modules	13664
DC capacity	5466 kW
Inverter rating	4200 kW
DC/AC ratio - Inv Rating	1.301

Weather	
Source	TMY3
GHI	1704.3 kWh/m2
DHI	kWh/m2
Global POA	2287.5 kWh/m2
Average Temp.	7.87 °C
Average Temp. (Generation)	12.45 °C
Average Wind	3.33 m/s
Average Wind (Generation)	3.61 m/s

PVsyst Input Parameters	
Transposition model	Perez
Constant thermal loss factor (Uc)	25.0 W/m2-K
Wind loss factor (Uv)	1.2 W/m2-K/m/s
Soiling losses	2.2 %
Light induced degradation	2.0 %
DC wiring loss	1.5 %
Module quality loss	-0.4 %
Module mismatch loss	1.0 %
DC health loss	1.0 %

AC System Losses	
MV transformer no-load losses	0.00%
MV transformer full load losses	0.00%
MV collection system	1.30%
HV transformer no-load losses	0.07%
HV transformer full load losses	0.48%
HV line	0.05%
Auxiliary	0.01%

BURNS & McDONNELL

Energy Production Summary

Burns & McDonnell, Energy Division

Project Name: **Pacificorp 2020 Renewables Technology Assessment**

Variant: VC0 Date: 26-Jun-20

Site Information	
City / State:	Milford, UT
Latitude (N):	38.41 °
Longitude (W):	-113.02 °
Altitude	0 m
ASHRAE Ext. Max Mean Temp	38.1 °C
ASHRAE 99.6% Heating DB	-19.8 °C

Estimated Annual Energy Production	
P50 net production (yr-1)	264852.0 MWh
AC capacity factor - Inv Rating	30.23%
AC capacity factor - POI Rating	30.23%
DC capacity factor	23.23%
Specific Production	2035 kWh/kWp/yr
Performance Ratio PR	80.39%
Night time losses	-398.3 MWh
Plant Output Limitations	0.00%

Design Parameters	
System DC Voltage	1500 VDC
GCR	42.6 %
Row spacing	10 m
Mounting	Tracker
Tilt angle or rotation limits	60 °
Azimuth	0 °
Tracking strategy	TRUE
Availability	100.0 %
Degradation	0.5 %/yr

Facility Level Information	
Nameplate Capacity	**130.13 MWDC**
Number of modules	325333
Nameplate Capacity	**100.00 MWAC**
Number of arrays	24
Interconnection Limit	**100.00 MWAC**
Inteconnection Voltage	34.5 kV
DC/AC ratio - POI Rating	1.301

Array Level Information	
Module rating	400 W
# Modules per string	28
Strings in parallel	488
Total number of modules	13664
DC capacity	5466 kW
Inverter Rating	4200 kW
DC/AC ratio - Inv Rating	1.301

Weather	
Source	TMY3
GHI	1903.4 kWh/m2
DHI	kWh/m2
Global POA	2531.7 kWh/m2
Average Temp.	9.92 °C
Average Temp. (Generation)	14.87 °C
Average Wind	2.11 m/s
Average Wind (Generation)	2.81 m/s

PVsyst Input Parameters	
Transposition model	Perez
Constant thermal loss factor (Uc)	25.0 W/m2-K
Wind loss factor (Uv)	1.2 W/m2-K/m/s
Soiling losses*	2.0 %
Light induced degradation	2.0 %
DC wiring loss	1.5 %
Module quality loss	-0.5 %
Module mismatch loss	1.0 %
DC health loss	1.0 %
Albedo*	1.0 %

AC System Losses	
MV transformer no-load losses	0.00%
MV transformer full load losses	0.00%
MV collection system	1.30%
HV transformer no-load losses	0.07%
HV transformer full load losses	0.48%
HV line	0.05%
Auxiliary	0.01%

Energy Production Summary

Burns & McDonnell, Energy Division

Project Name: **Pacificorp 2020 Renewables Technology Assessment**

Variant: VC0 Date: 26-Jun-20

Site Information		
City / State:	Milford, UT	
Latitude (N):	38.41	°
Longitude (W):	-113.02	°
Altitude	0	m
ASHRAE Ext. Max Mean Temp	38.1	°C
ASHRAE 99.6% Heating DB	-19.8	°C

Design Parameters		
System DC Voltage	1500	VDC
GCR	42.6	%
Row spacing	10	m
Mounting	Tracker	
Tilt angle or rotation limits	60	°
Azimuth	0	°
Tracking strategy	TRUE	
Availability	100.0	%
Degradation	0.5	%/yr

Array Level Information		
Module rating	400	W
# Modules per string	28	
Strings in parallel	488	
Total number of modules	13664	
DC capacity	5466	kW
Inverter Rating (Max Temp & 95% pf)	4200	kW
DC/AC ratio - Inv Rating	1.301	

PVsyst Input Parameters		
Transposition model	Perez	
Constant thermal loss factor (Uc)	25.0	W/m2-K
Wind loss factor (Uv)	1.2	W/m2-K/m/s
Soiling losses*	2.0	%
Light induced degradation	2.0	%
DC wiring loss	1.5	%
Module quality loss	-0.5	%
Module mismatch loss	1.0	%
DC health loss	1.0	%
Albedo*	1.0	%

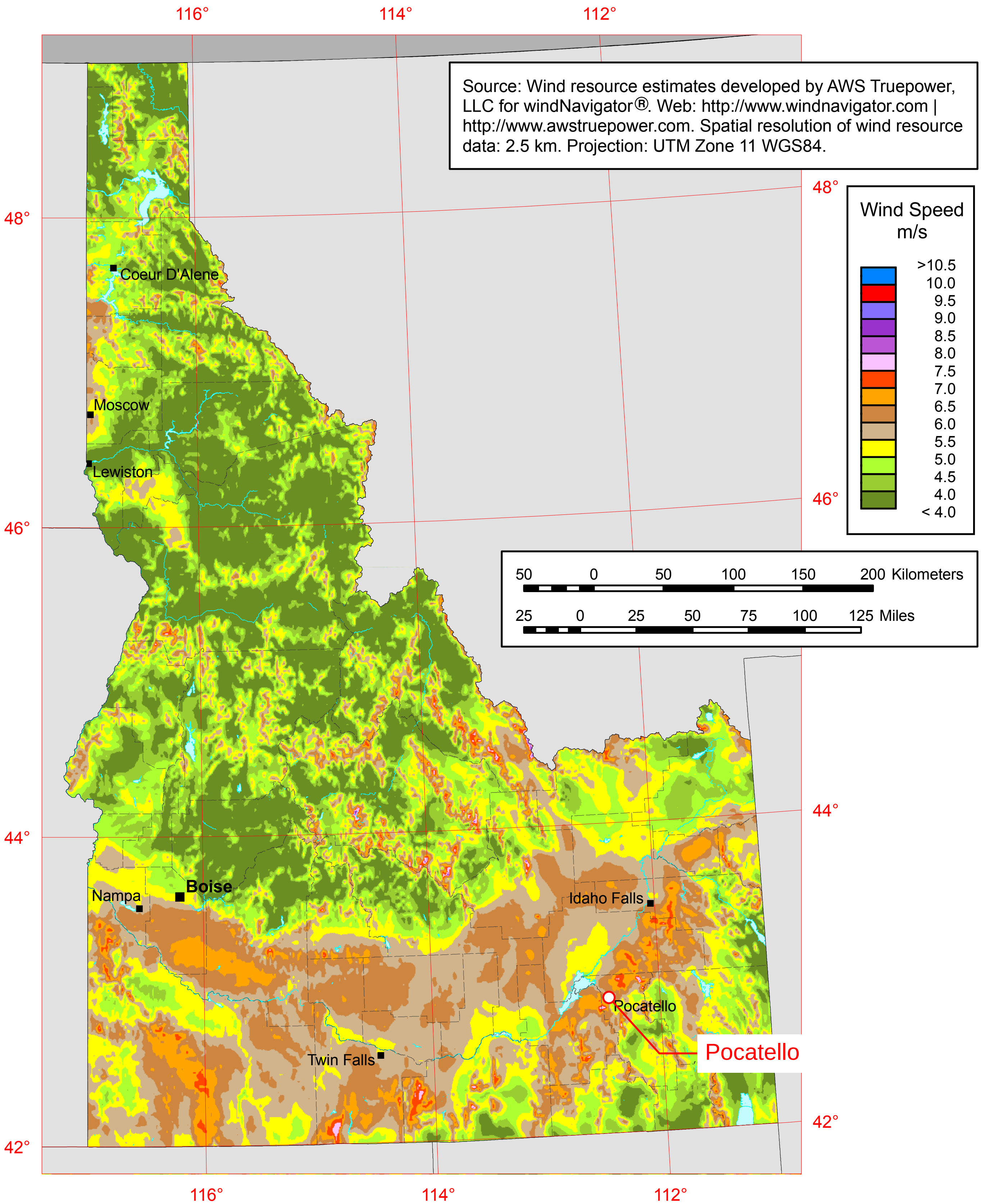
Estimated Annual Energy Production		
P50 net production (yr-1)	529704.0	MWh
AC capacity factor - Inv Rating	30.23%	
AC capacity factor - POI Rating	30.23%	
DC capacity factor	23.23%	
Specific Production	2035	kWh/kWp/yr
Performance Ratio PR	80.39%	
Night time losses	-796.6	MWh
Plant Output Limitations	0.00%	

Facility Level Information		
Nameplate Capacity	**260.27**	**MWDC**
Number of modules	650667	
Nameplate Capacity	**200.00**	**MWAC**
Number of arrays	48	
Interconnection Limit	**200.00**	**MWAC**
Inteconnection Voltage	230	kV
DC/AC ratio - POI Rating	1.301	

Weather		
Source	TMY3	
GHI	1903.4	kWh/m2
DHI		kWh/m2
Global POA	2531.7	kWh/m2
Average Temp.	9.92	°C
Average Temp. (Generation)	14.87	°C
Average Wind	2.11	m/s
Average Wind (Generation)	2.81	m/s

AC System Losses	
MV transformer no-load losses	0.00%
MV transformer full load losses	0.00%
MV collection system	1.30%
HV transformer no-load losses	0.07%
HV transformer full load losses	0.48%
HV line	0.05%
Auxiliary	0.01%

Idaho - Annual Average Wind Speed at 80 m



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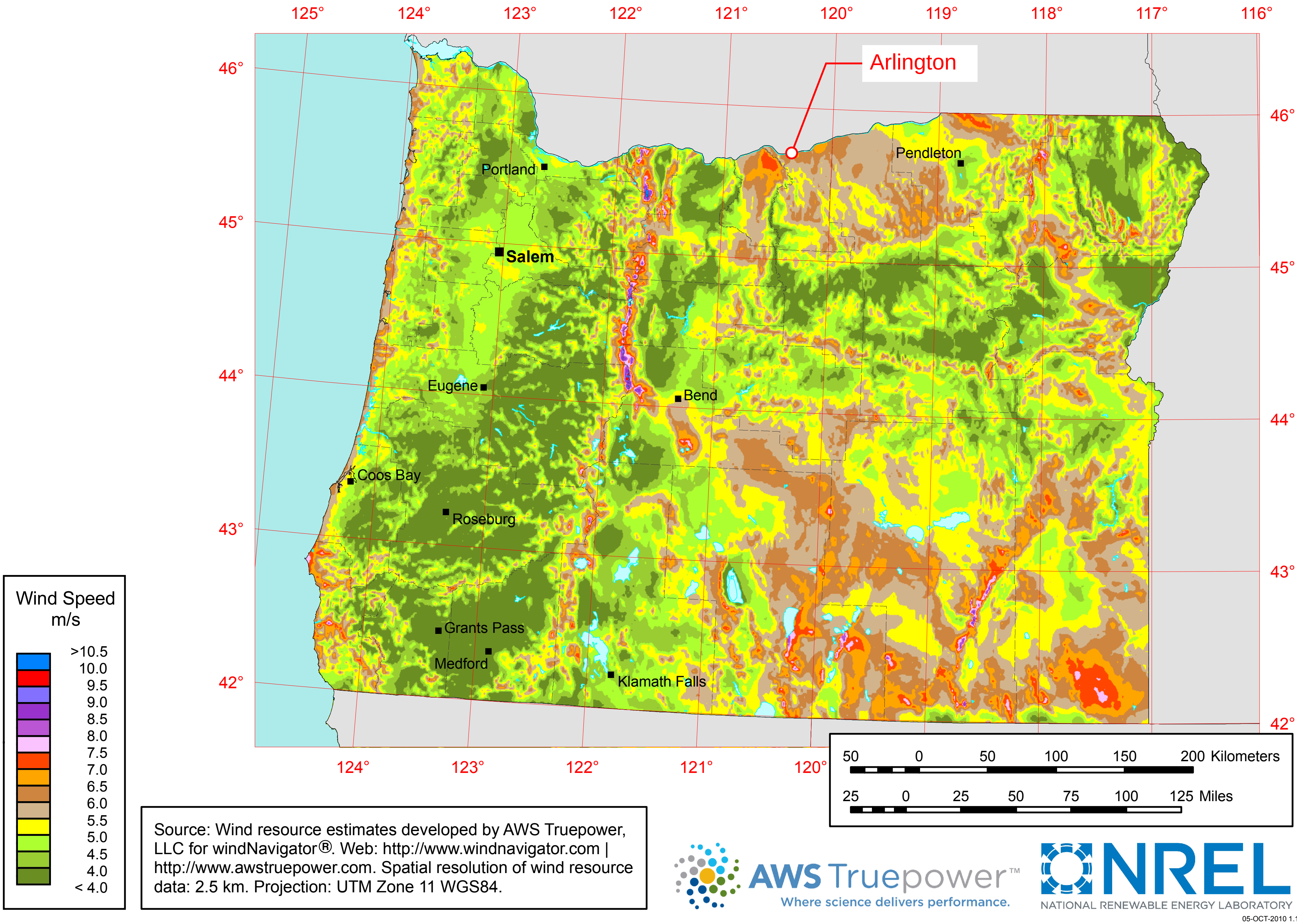
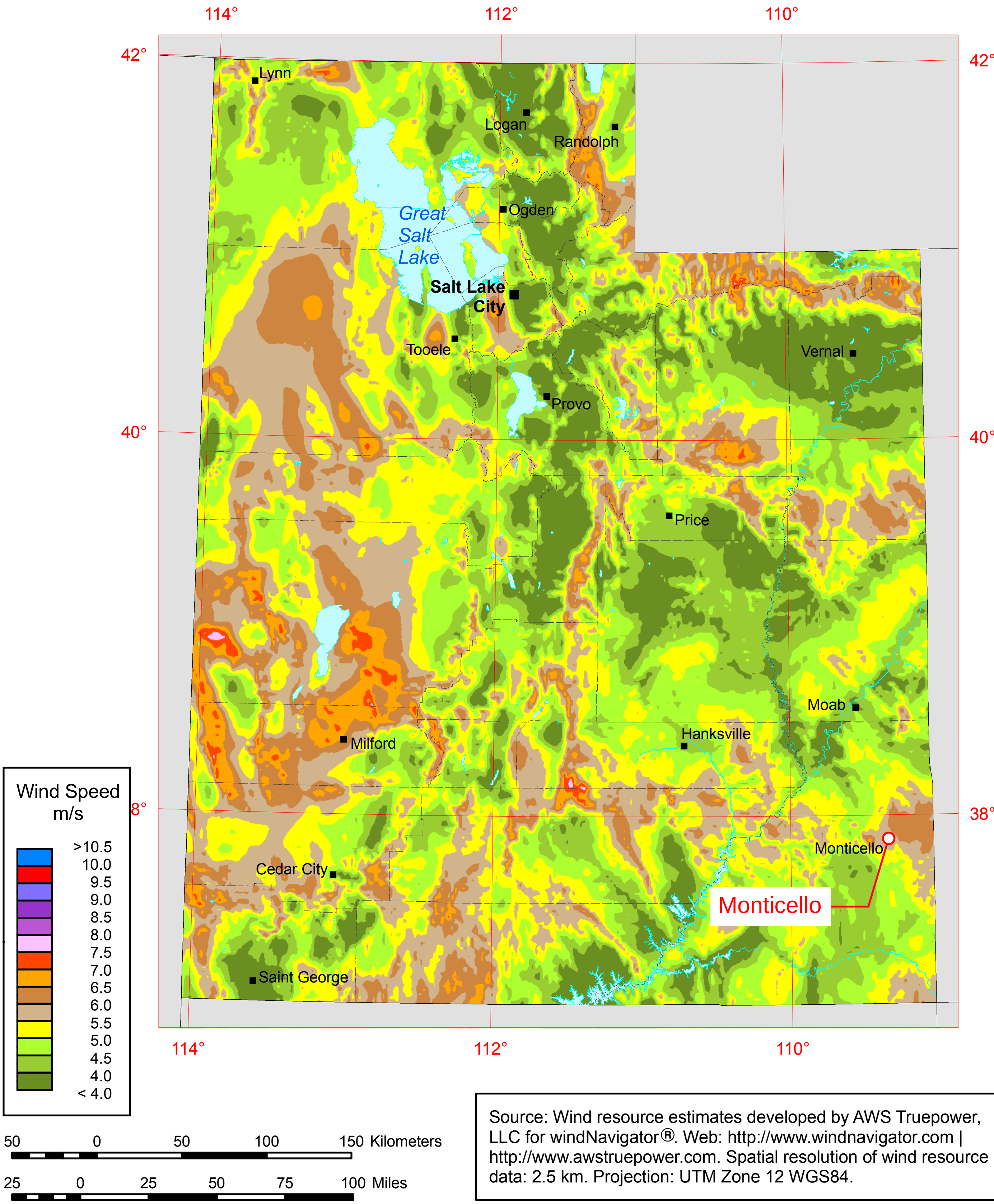
06-OCT-2010 1.1.1

Oregon - Annual Average Wind Speed at 80 m



Source: Wind resource estimates developed by AWS Truepower, LLC for windNavigator®. Web: http://www.windnavigator.com | http://www.awstruepower.com. Spatial resolution of wind resource data: 2.5 km. Projection: UTM Zone 11 WGS84.

Utah - Annual Average Wind Speed at 80 m



Source: Wind resource estimates developed by AWS Truepower, LLC for windNavigator®. Web: http://www.windnavigator.com | http://www.awstruepower.com. Spatial resolution of wind resource data: 2.5 km. Projection: UTM Zone 12 WGS84.

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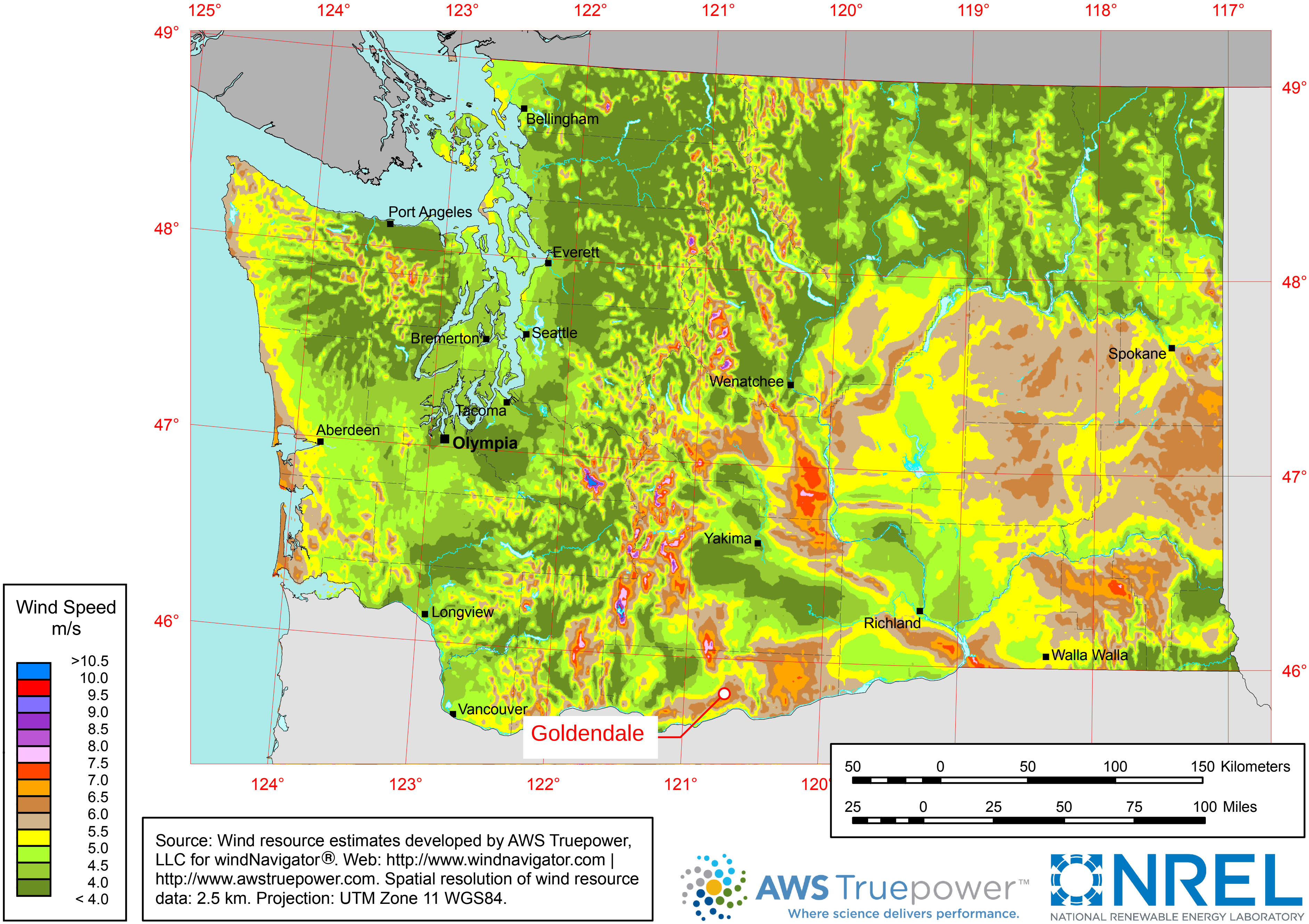
Washington - Annual Average Wind Speed at 80 m



Source: Wind resource estimates developed by AWS Truepower, LLC for windNavigator®. Web: http://www.windnavigator.com | http://www.awstruepower.com. Spatial resolution of wind resource data: 2.5 km. Projection: UTM Zone 11 WGS84.

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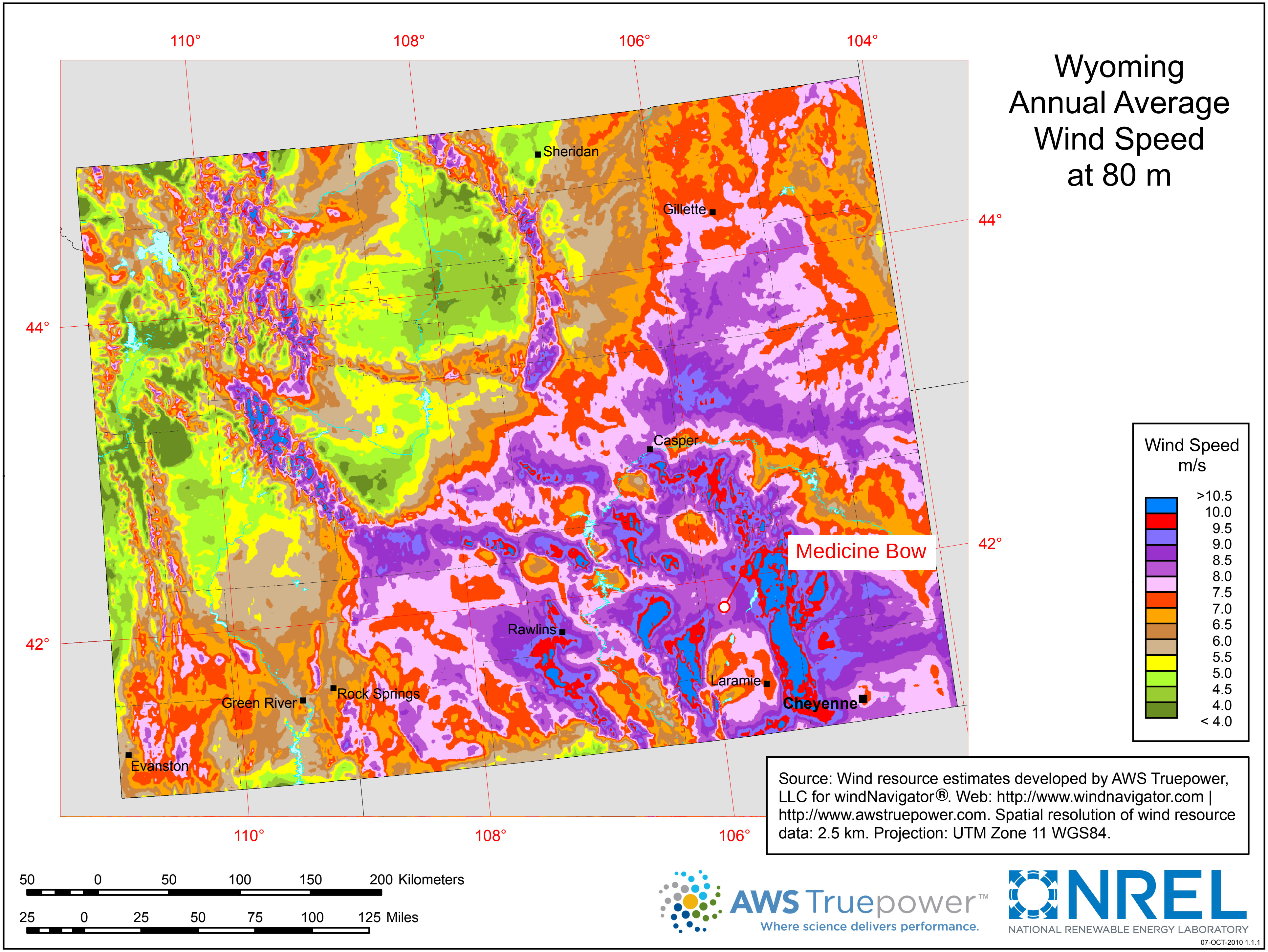
05-OCT-2010 1.1.1


Wyoming
Annual Average
Wind Speed
at 80 m
110°
108°
106°
104°
44°
42°
Sheridan
Gillette
Casper
Medicine Bow
Rawlins
Laramie
Cheyenne
Rock Springs
Green River
Evanston
Wind Speed
m/s
>10.5
10.0
9.5
9.0
8.5
8.0
7.5
7.0
6.5
6.0
5.5
5.0
4.5
4.0
< 4.0
Source: Wind resource estimates developed by AWS Truepower, LLC for windNavigator®. Web: http://www.windnavigator.com | http://www.awstruepower.com. Spatial resolution of wind resource data: 2.5 km. Projection: UTM Zone 11 WGS84.
50 0 50 100 150 200 Kilometers
25 0 25 50 75 100 125 Miles
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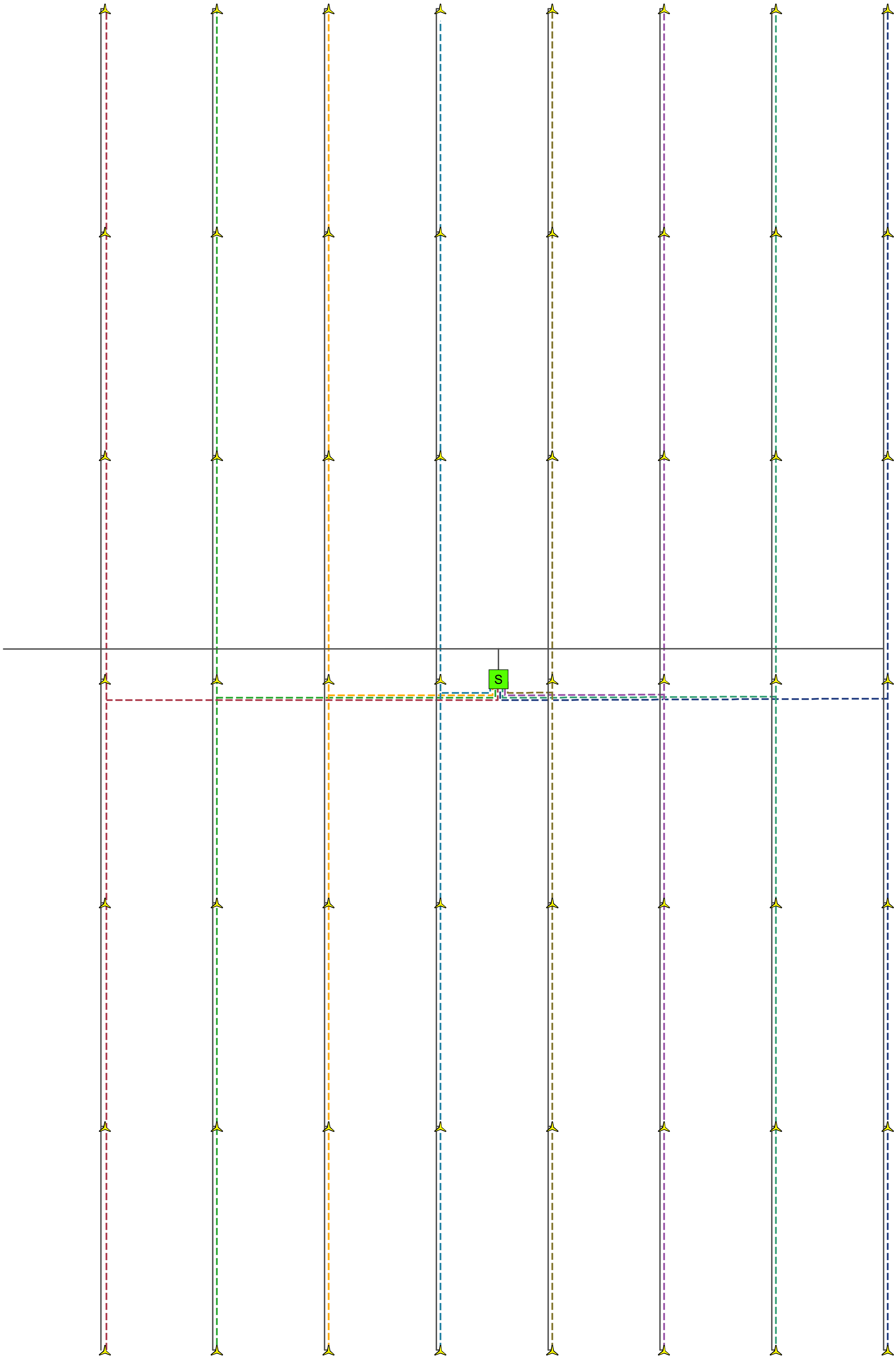


Drawing Notes:
1. Layout is intended to be generic / conceptual and not necessarily representative of a site that would be constructed. Layout based upon generic turbine model with approx. 414m by 828m gridded spacing. Final turbine model, project size, and site conditions will alter layout.

PRELIMINARY
NOT FOR CONSTRUCTION

LEGEND

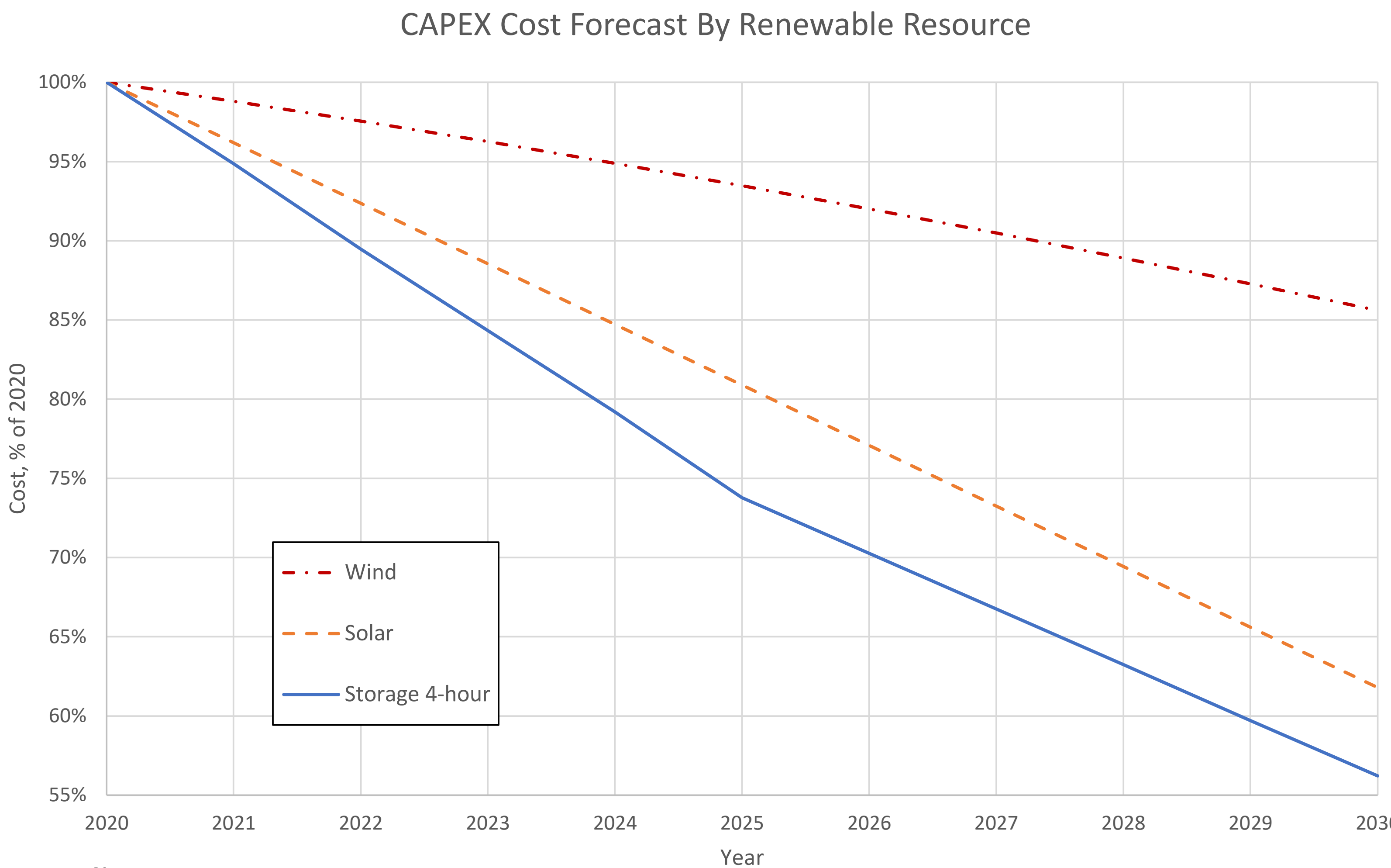
- Proposed Turbine
- Collector Substation
- Access Roads
- Circuit 1
- Circuit 2
- Circuit 3
- Circuit 4
- Circuit 5
- Circuit 6
- Circuit 7
- Circuit 8

REFERENCE

GENERIC SITE LAYOUT
200 MW Wind Farm

LOCATION:	Generic
CLIENT:	Pacificorp
PROJ. NO.:	109571
CREATED:	09/06/2018

BURNS McDONNELL
www.burnsmcd.com



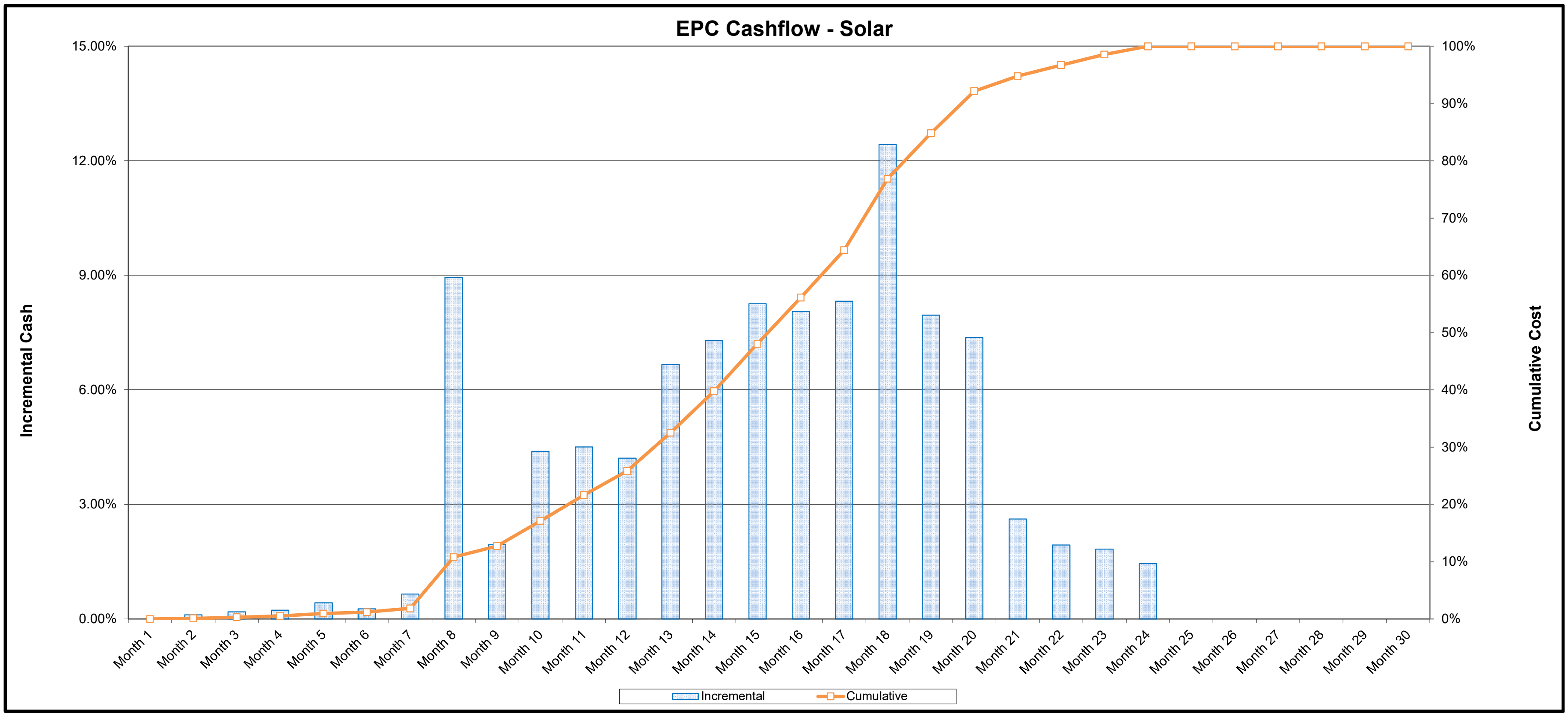
Notes:

1. The declining cost curve for onshore wind was developed using NREL Land-Based Wind Classes (Class) moderate overnight cost inforamtion. The costs for Class 2, Class 6, and Class 8 were averaged to represent the Pacificorp identified sites based on average wind speed.

2. The declining cost curve for utility solar photovoltaic was developed using NREL mid overnight cost inforamtion.

3. The declining cost curve for battery storage was developed using NREL mid overnight CAPEX cost information for a storage device with 15-year life and 85% round-trip efficiency for 4- hour storage.

Overnight Cost Forecast ($/kW)											
Technology	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Wind	$1,684.96	$1,664.76	$1,643.66	$1,621.65	$1,598.74	$1,574.92	$1,550.20	$1,524.58	$1,498.05	$1,470.62	$1,442.28
Percentage of 2020	100.00%	98.80%	97.55%	96.24%	94.88%	93.47%	92.00%	90.48%	88.91%	87.28%	85.60%
Solar	$1,324.76	$1,274.15	$1,223.53	$1,172.91	$1,122.30	$1,071.68	$1,021.06	$970.45	$919.83	$869.22	$818.60
Percentage of 2020	100.00%	96.18%	92.36%	88.54%	84.72%	80.90%	77.08%	73.25%	69.43%	65.61%	61.79%
Storage ($/kWh)	$370.00	$351.00	$331.00	$312.00	$293.00	$273.00	$260.00	$247.00	$234.00	$221.00	$208.00
Percentage of 2020	100.00%	94.86%	89.46%	84.32%	79.19%	73.78%	70.27%	66.76%	63.24%	59.73%	56.22%



EPC Cashflow - Solar
Incremental Cash
Cumulative Cost
15.00%
12.00%
9.00%
6.00%
3.00%
0.00%
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Month 1
Month 2
Month 3
Month 4
Month 5
Month 6
Month 7
Month 8
Month 9
Month 10
Month 11
Month 12
Month 13
Month 14
Month 15
Month 16
Month 17
Month 18
Month 19
Month 20
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Month 22
Month 23
Month 24
Month 25
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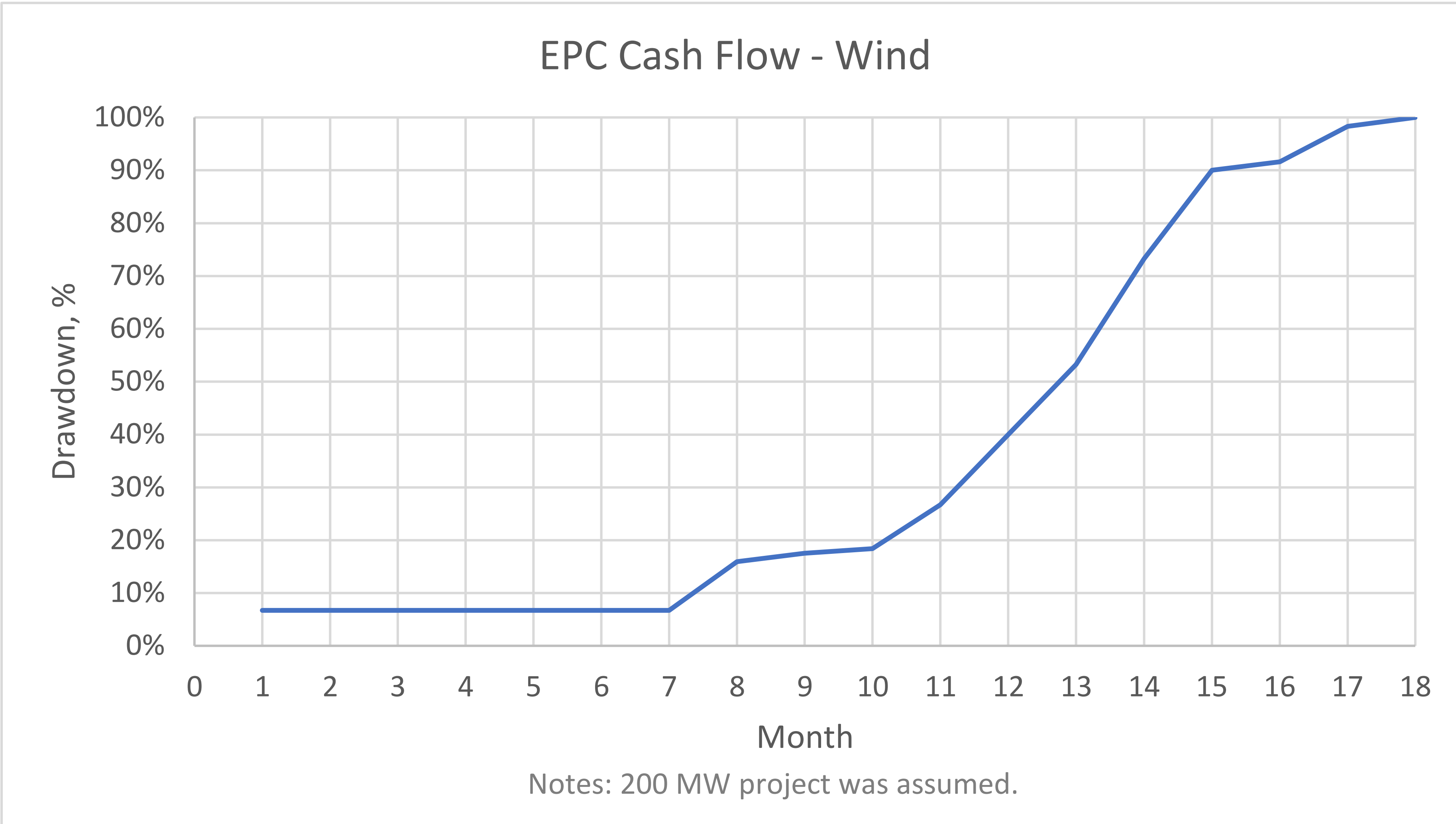
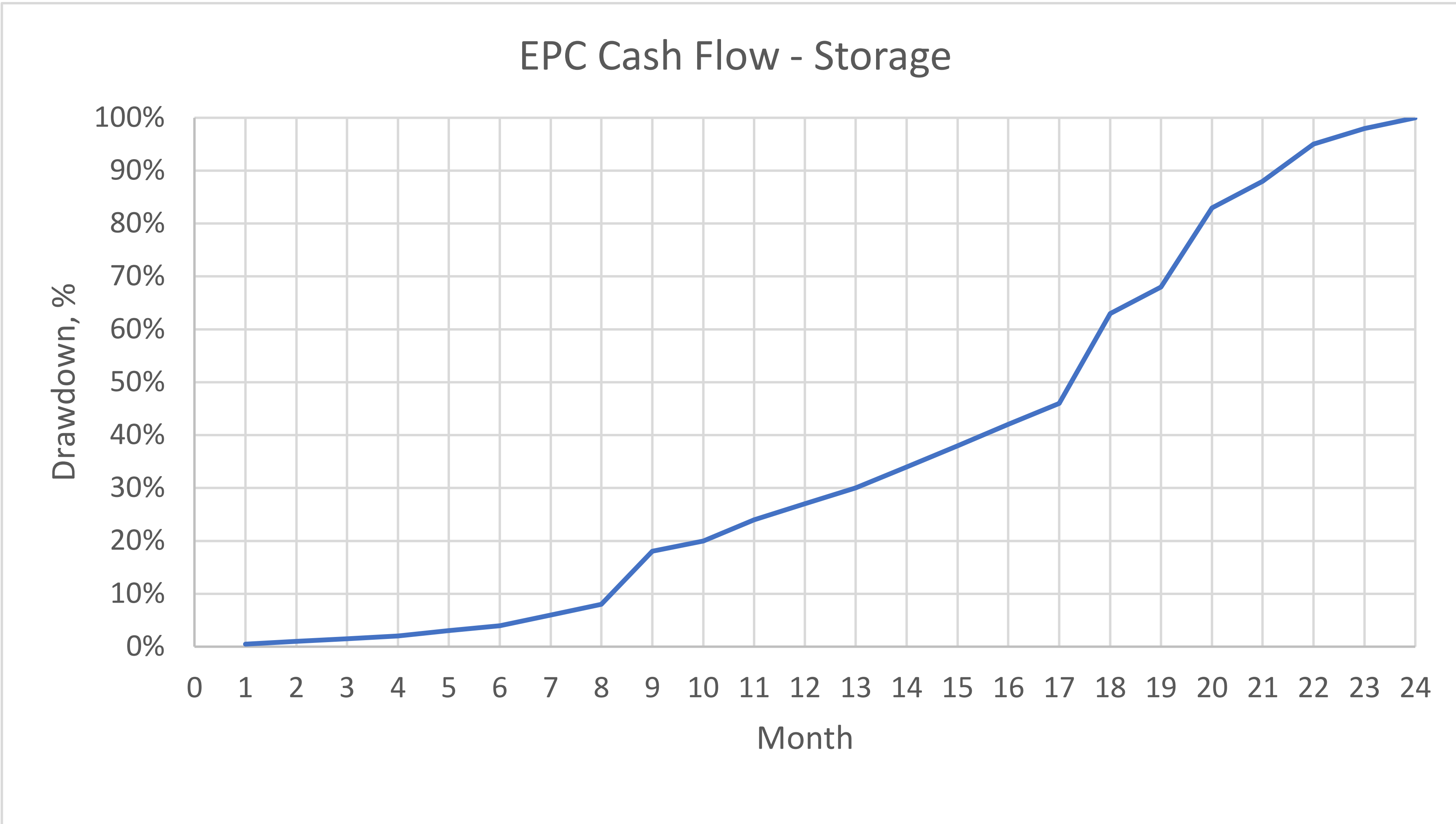
Month 27
Month 28
Month 29
Month 30
Incremental
Cumulative


EPC Cash Flow - Wind
Drawdown, %
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18
Month
Notes: 200 MW project was assumed.


EPC Cash Flow - Storage
Drawdown, %
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Month

25 - Year Cashflows

200 MW UT Solar

Year:	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
Capital Cost, $MM:	$ 216.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11.59	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
O&M, $MM:	$ -	$ 3.59	$ 3.68	$ 3.77	$ 3.86	$ 3.96	$ 4.06	$ 4.16	$ 4.26	$ 4.37	$ 4.48	$ 4.59	$ 4.71	$ 4.82	$ 4.95	$ 5.07	$ 5.20	$ 5.33	$ 5.46	$ 5.60	$ 5.74	$ 5.88	$ 6.03	$ 6.18	$ 6.33	$ 6.49

200 MW UT Wind

Year:	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
Capital Cost, $MM:	$ 231.00	$ -	$ -	$ 0.44	$ 0.45	$ 0.46	$ 0.89	$ 0.91	$ 0.93	$ 0.96	$ 0.98	$ 1.67	$ 1.72	$ 1.76	$ 1.80	$ 1.85	$ 1.89	$ 1.94	$ 1.99	$ 2.04	$ 2.09	$ 3.00	$ 3.07	$ 3.15	$ 3.23	$ 3.31
O&M, $MM:	$ -	$ 10.46	$ 10.72	$ 10.98	$ 11.26	$ 11.54	$ 11.83	$ 12.12	$ 12.43	$ 12.74	$ 13.06	$ 13.38	$ 13.72	$ 14.06	$ 14.41	$ 14.77	$ 15.14	$ 15.52	$ 15.91	$ 16.31	$ 16.71	$ 17.13	$ 17.56	$ 18.00	$ 18.45	$ 18.91

50 MW 200 MWh Storage

Year:	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Capital Cost, $MM:	$ 68.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4.71	$ -	$ -	$ -	$ -	$ -
O&M, $MM:	$ -	$ 1.41	$ 1.45	$ 1.49	$ 1.52	$ 1.56	$ 1.60	$ 1.64	$ 1.68	$ 1.72	$ 1.77	$ 1.81	$ 1.86	$ 1.90	$ 1.95	$ 2.00	$ 2.05	$ 2.10	$ 2.15	$ 2.21	$ 2.26

APPENDIX N – ENERGY STORAGE POTENTIAL EVALUATION

Introduction

Energy storage resources can provide a wide range of grid services and can be flexibly sized and sited. Many of these grid services have been increasing in value with increasing penetration of variable energy resources such as wind and solar, while energy storage costs have been falling. As a result, storage resources are an increasing component of PacifiCorp's least-cost, least-risk preferred portfolio. While the 2021 IRP portfolio analysis captures the system benefits of energy storage, it does not fully account for localized benefits and siting opportunities. This appendix provides details on how energy storage resources can be configured to maximize the benefits they provide.

Because energy storage resources are highly flexible, with the ability to respond to dispatch signals and act as both a load and a resource, they can potentially provide any of the grid services discussed herein. Other types of resources, including distributed generation, energy efficiency, and interruptible loads can also provide one or more of these grid services, and can complement or provide lower-cost alternatives to energy storage. Given that broad applicability, Part 1 of this appendix first discusses a variety of grid services as generically and broadly as possible. Part 2 discusses the key operating parameters of energy storage and how those operating parameters relate to the grid services in Part 1. Finally, Part 3 discusses how to optimize the configuration and dispatch of energy storage and other distributed resources to maximize the benefits to the local grid and the system. Part 3 also provides examples of specific applications and examples of applications that may be cost-effective in the future.

Part 1: Grid Services

PacifiCorp must ensure that sufficient energy is generated to meet retail customer demand at all times. It also must maintain resources that can respond to changing system conditions at short notice, these operating reserves are held in accordance with reliability standards established by the National Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC). Both energy and operating reserves are dispatch-based, and dependent on the specific conditions at a specific place and time. These values are generally independent from hour to hour, as removing a resource in a subset of hours may not impact the value in the remaining hours.

Because load can be higher than expected and some resources may be unavailable at any given time, sufficient generation resources are needed to ensure that energy and operating reserve requirements can be met with a high degree of confidence. This is referred to as generation capacity. The transfer of energy from the locations where it is generated to the locations where it is delivered to customers requires poles, wires, and transformers, and the capability of these assets is referred to as transmission and distribution (T&D) capacity. Generation and T&D capacity are both generally asset-based, and provide value by allowing changes in the resources and T&D elements. In general, assets cannot be avoided based on changes to a subset of the hours in which they are needed and only limited changes are possible once constructed or contracted. It should also be noted that the impact of asset or capacity changes on dispatch must also be included in any valuation.

These obligations are broken down into the following grid services, which are discussed in this section:

- Energy, including losses;
- Operating reserves, including:
  - Spinning reserve;
  - Non-spinning reserve;
  - Regulation and load following reserves; and
  - Frequency response;
- Transmission and distribution capacity; and
- Generation capacity.

Energy Value

Background

Because PacifiCorp's load and resources must be balanced at all times, when an increment of generation is added to PacifiCorp's system, an increment of generation must also be removed. This could take the form of a generator that is backed down, an avoided market purchase, or an additional market sale. The cost of the increment that is removed (or the revenue from the sale), represents the energy value, and this value varies by location and by time. Location can also impact line losses relative to the generation which would otherwise have been dispatched, with losses manifesting as a larger effective volume. With regard to time, there are two relevant time scales: hourly values, and sub-hourly values.

The energy value in a location is dependent on PacifiCorp's load and resource balance, the dispatch cost of its resources, and the transmission capability connecting those resources to load. Differences in energy value occur when the economic resources in area exceed the transmission export capability to an area that must then use higher cost resources to serve load. Once transmission is fully utilized, the higher cost resources must be deployed to serve the importing area and lower cost resources will be available in the exporting area. As a result, the value in each location will reflect the marginal resources used to serve load in each area. If transfers are not fully utilized in either direction, the marginal resource in both areas would be the same, and the energy value would be the same.

Both load and resource availability change significantly across the day and across the year. Differences in value over time are driven by the cost of the marginal resource needed to serve load, which changes when load or resource availability change. When load goes up, or the supply of lower-cost resources goes down, the marginal resource needed to serve load will be more expensive.

The value by location is also dependent on the losses relative to the generation which would otherwise have been dispatched. Losses occur during the transfer of energy across the T&D system to a customer's location. As distance and voltage transformation increase, more generation must be injected to meet a customer's demand. For example, a distributed resource that is close to customer load or located on the same voltage level can avoid both energy at its location as well as the losses which otherwise would have occurred in delivering energy to that location. As a result, the marginal generation resource's output may be reduced by an amount greater than the metered output of a distributed resource. This increase in volume due to losses is also relevant to generation and T&D capacity value.

Modeling

There are two basic sources of energy values: market price forecasts and production cost models. There are also two relevant time scales: hourly values, and sub-hourly values.

PacifiCorp produces a non-confidential official forward price curve (OFPC) for the major market points in which it typically transacts on a quarterly basis. The OFPC represents the price at which power would be transacted today, for delivery in a future period. The OFPC contains prices for each month for heavy load hour (HLH) and light load hour (LLH) periods and goes forward approximately 20 years.[1] However, not all hours in the HLH or LLH periods have equal value. To differentiate between hours, PacifiCorp uses scalars calculated based on historical hourly results. For PacifiCorp's operations and production cost modeling, scalars are based on the California Independent System Operator's day-ahead hourly market prices. Because these values are used in operations, the details on the methodology and the resulting prices are treated confidentially. To allow for transparency, PacifiCorp has also developed non-confidential scalars using historical Energy Imbalance Market prices. With either scalars, the result is a forecast of hourly market prices that averages to the values in the OFPC over the course of a month. Using hourly market price to calculate energy value implies that market transactions are either the avoided resource, or a reasonable representation of the avoided resource's marginal cost in any given interval.

Production cost models contain a representation of an electric power system, including its load, resources, and transmission rights, as well as markets where power can be bought or sold. They also account for operating reserve obligations and the resources held to cover those obligations. All models are simplified representations, and there are several key simplifying assumptions. The granularity of a model is its smallest calculated timestep. While calculating twice as many timesteps should take roughly twice as long from a mechanical standpoint, evaluating decisions that span multiple time steps (such as when to charge or discharge a battery, or when to start or shutdown a thermal resource) requires the evaluation of multiple timesteps at once, resulting in a larger more complicated problem that can take longer to solve. In addition, maintaining inputs to represent smaller timesteps is more complicated, and a model is only as good as its inputs. To simplify the representation of location, transmission areas can be defined by the key transmission constraints which separate them, with transmission within each area assumed to be unconstrained. Another simplifying assumption is to model all load and resources at a level equivalent to generator input. For instance, load is "grossed up" from the metered volume to a level that includes the estimated losses necessary to serve it. This allows for a one for one relationship between all volumes, which vastly simplifies the model.

PacifiCorp's production cost modeling for the 2021 IRP uses the Plexos model and reflects system dispatch at an hourly granularity. While the IRP modeling uses the hourly market prices from the OFPC as inputs, a distributed resource's energy value will depend on its location and other characteristics and can be either higher or lower than the market price in a given hour. Generally, a resource's value is based on the difference between two production cost model studies: one with

[1] HLH is 6:00 a.m. to 10:00 p.m. Pacific Prevailing Time Monday through Saturday, excluding NERC holidays. LLH is all other hours.

the resource included, and one with the resource excluded. This explicitly identifies the marginal resources dispatched in the absence of the resource being evaluated. The Plexos model offers an alternative in that it reports the value of energy produced by each resource, by multiplying that resource's output by the marginal price in that resource's location for each hour. A comparable calculation is performed for operating reserves. This provides an estimate of the marginal benefits from any resource in the portfolio, without the need for with and without studies. However, for large resources or significant portfolio changes, with and without studies may still be necessary, as the reported results reflect the marginal cost of the last increment of generation, rather than the average across all of the resource's output.

More detailed models of the electrical power system also exist, for instance PacifiCorp uses physical models for grid operations and planning that account for power flows and the loading of individual system elements. Similarly, the California Independent System Operator (CAISO) uses a "Full Network Model" with detailed representations of all resources and loads, as well as the transmission system. CAISO's model includes a representation of PacifiCorp's system for the purpose of dispatching resources in the Western Energy Imbalance Market (EIM), and models a five minute granularity for that purpose. The added detail these physical models produce comes from a significant increase in the complexity of inputs and computational requirements.

Table N.1 contains nominal levelized energy margin values for various energy storage technologies in 2024-2040, and reflects marginal values reported by the Plexos model for specific resources in the preferred portfolio.

Table N.1 - Energy Margin by Energy Storage Technology

Technology	Hours of Storage	Efficiency (%)	Levelized Energy Margin (2024-2040) ($/kw-yr)
Lithium Ion	4	85%	$31.34
Lithium Ion (combined with solar)	4	85%	$21.89
Molten Salt (Nuclear)	5.5	99%	$53.45

These energy values will vary by location, volume, and operating reserve requirements, as well as with changes in the portfolio.

The Plexos model identifies resources to carry operating reserves for each hour, but does not include the intra-hour changes that would cause those resources to be deployed. Because resources that are dispatchable within the hour can be dispatched up when marginal energy costs are high, and down when marginal energy costs are low, this can result in incremental value relative to an hourly market price or hourly production cost model result. In practice, sub-hourly dispatch benefits are largely derived from PacifiCorp's participation in EIM, and the specific rules associated with that market. For instance, resources must be participating in EIM in order to receive settlement payments based on their five-minute dispatches. Resources that are not participating receive settlement payments based on their hourly imbalance. Furthermore, because non-participating resources are not visible to the market, their sub-hourly dispatch would not impact the market solution. Because distributed resources can be aggregated for purposes of EIM participation, size should not be an impediment; however, the structure of the EIM may dictate some aspects of their use and would need to be aligned with the other services a distributed resource provides. While intra-hour dispatch is a key aspect of reliable system operation, and potentially an additional source of revenue for flexible resources, it is difficult to represent the interactions between hourly dispatch in Plexos and sub-hourly dispatch in EIM – since they have finite storage capability, a battery that is discharged in response to high prices in EIM is likely to forego dispatch at relatively high prices in a later interval. In addition, imbalance in the EIM is finite in both duration and magnitude and the battery resources added in PacifiCorp's preferred portfolio could easily move the market thereby drastically reducing the frequency of price excursions and the associated intra-hour revenue. For these reasons, PacifiCorp has not quantified the costs or benefits of intra-hour dispatch for the 2021 IRP, but expects to continue evaluating them as its portfolio and the market itself continue to evolve.

Operating Reserve Value

Background

Operating reserve is defined by NERC as "the capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection."[2] Operating reserves are capability that is not currently providing energy, but which can be called upon at short notice in response to changes in load or resources. Operating reserves and energy are additive – a resource can provide both at the same time, but not with the same increment of its generating capability. Operating reserves can also be provided by interruptible loads, which have an effect comparable to incremental resources. Additional details on operating reserve requirements are provided in Volume II, Appendix F (Flexible Reserve Study).

As with energy value, operating reserve value is based on the marginal resource that would otherwise supply operating reserves, and varies by both location, time, and the speed of the response. Because operating reserve requirements are primarily applied at the Balancing Authority Area (BAA) level, the associated value is typically uniform within each of PacifiCorp's BAAs. An exception to this is that operating reserves must be deliverable to balance load or resources, so unused capability in a constrained bubble without additional export capability does not count toward the meeting the requirements. Operating reserve value is somewhat indirect in comparison to energy value, as it relates to the use of the freed up capacity on units that would otherwise be holding reserves. If that resource's incremental energy is less expensive that what is currently dispatched, it can be dispatched up, and more expensive energy can be dispatched down. The value of the operating reserves in that instance is the margin between the freed up energy and the resource that is dispatched down. Note that the dispatch price of the resource being evaluated does not impact the value, since holding operating reserves does not require dispatch. When the freed up resource is more expensive than what is currently dispatched, it will not generate more when the operating reserve requirement is removed, and the value of operating reserves would be zero. With this in mind, operating reserves are generally held on the resources with the highest dispatch price. Finally, operating reserve value is limited by the speed of the response: how fast a unit can ramp up in a specified time period, and how soon it begins to respond after receiving a dispatch signal. Reliability standards require a range of operating reserve types, with response times ranging from seconds to thirty minutes.

[2] NERC Glossary of Terms: http://www.nerc.com/files/glossary_of_terms.pdf, updated May 13, 2019.

Modeling

As discussed above, the value of incremental operating reserves is equal to the positive margin between the dispatch cost of the lowest cost resource that was being held for reserve, and the dispatch cost of the highest cost resource that was dispatched for energy. Similar to the value of energy, the price of different operating reserve types could be forecasted by hour, based on forecasts of reserve capability, demand, and resource dispatch costs. Given the range and variability in these components, this would be an involved calculation. In addition, because operating reserves are a small fraction of load, they are more sensitive to volume than energy. For instance, spinning reserve obligations are approximately three percent of load in each hour. As a result, resource additions may rapidly cover that portion of PacifiCorp's requirement met by resources that could otherwise provide economic generation and which produce a margin when released from reserve holding. This is particularly true for batteries and interruptible load resources that can respond rapidly and thus count all or most of their output toward reserve obligations.

While a market price for operating reserve products does not align well with PacifiCorp's system, the specifics of the calculation described above are embedded within PacifiCorp's production cost models. Those models allocate reserves first to energy limited resources in those periods where they could generate but are not scheduled to do so. Examples of energy limited resources include interruptible loads, hydro, and energy storage. If called on for reserves, these resources would lose the ability to generate in a different period, so the net effect on energy value for that resource is relatively small. As a result, the unused capacity on these resources can't be used for generation, but that also means it can count as reserves without forgoing any generation and incurring a cost to do so. After operating reserves have been fully allocated to the available energy-limited resources, reserves are allocated to the highest cost generators with reserve capability in the supply stack, up to each unit's reserve capability, until the entire requirement is met. This is generally done prior to generation dispatch and balancing, because the requirements are input to the model or based on a formula and aren't typically restricted based on transmission availability. After the reserve allocations are complete, the remaining dispatch capability of each unit is used to develop an optimized balance of load and resources.

As part of the calculation of wind and solar integration costs reported in Volume II, Appendix F (Flexible Reserve Study), PacifiCorp assessed the cost of holding incremental operating reserves. That study identified a cost of approximately $29/kw-yr (2020$), based on a 2023-2040 study period. This value would be applicable to any resource that provided operating reserves uniformly throughout the year. Similar to reporting on energy values, the Plexos model also reports operating reserve revenues specific to each modeled resource, accounting for availability, location, and use for energy dispatch (during which a resource could not also provide reserves with any portion of its capacity that was generating energy). As with the annual wind and solar costs shown in Appendix F, operating reserve value is projected to be highest in the near term and decline across the study horizon as the amount of battery resources on the system increases.

Transmission and Distribution Capacity

The 2021 IRP included endogenous transmission upgrades as part of portfolio selection. This allows the cost of transmission upgrades to be considered as part of the modeled cost of resources in each area. However, because energy efficiency and load control are customer-sited, they are not subject to these constraints, placing them at an advantage relative to both thermal and renewable resource options. For some sizes and locations, distributed resources can also potentially avoid significant transmission upgrades and may help to defer distribution system investments. While the cost of specific T&D projects varies, a generic system wide estimate of transmission upgrade costs is included as a credit to energy efficiency in the 2021 IRP, and amounts to $6.34/kw-year (2020$). In practice, these costs would vary by project and some transmission upgrades would not be suitable for deferral by distributed resources. Because of the large scale of many transmission upgrades, and the binary nature of the expenditures, it may be difficult to procure adequate distributed resources to cover the need in a timely fashion and in accordance with reliability requirements, though it is always appropriate to consider the available options when considering expenditures on an upgrade. Distribution capacity upgrades are more likely to be suitable for deferral by a distributed resource, as the scale of the need is closer to that of these types of resources.

To that end, PacifiCorp maintains an "Alternative Evaluation Tool" which is used to screen the list of projects identified during T&D planning to assess where distributed resources, including energy storage, could be both technically feasible and cost competitive as compared to traditional T&D solutions. If a study shows that distributed resource alternatives are feasible and potentially cost-competitive that project is flagged for detailed analysis.

To help illustrate the potential for distribution capacity deferral, PacifiCorp assessed the peak loading and forecasted growth at each of the distribution substations across its system. Once peak loading reaches 90 percent of a distribution substation's capability, PacifiCorp takes steps to either reconfigure the loads or add capacity to ensure that it remains sufficient to serve customers. For this analysis, substations were classified as having a high potential for distribution capacity deferral if their current loading is at or above the 90 percent threshold, medium if they are anticipated to exceed the 90 percent threshold within the next twenty years, and low if they are not expected to exceed the 90 percent threshold in the next twenty years. The results shown in Table N.2 identify the portion of PacifiCorp's distribution load that is part of each of these three categories in each state. The "low" category represents a majority of PacifiCorp's system, which indicates that programs targeting distributed resources in specific locations have the potential to provide significantly greater value.

Table N.2 – Share of Distribution Load by State with Potential Upgrade Deferral

	Threshold	CA	OR	WA	ID	UT	WY	Total
High	Above 90% Utilization	5%	8%	19%	14%	12%	1%	10%
Medium	Within 20 years	5%	25%	27%	46%	34%	18%	29%
Low	Beyond 20 years	90%	68%	54%	41%	54%	81%	61%

Because distribution upgrades are primarily driven by load growth, distributed resources need to be sufficient to maintain load within existing peaks to defer distribution upgrades. Energy storage resources can be cost-effective to cover brief peaks, but are less cost-effective as the duration of the shortfall increases. To the extent load in an area continues to grow, the deferred distribution upgrade is likely to be necessary eventually. Table N.3 illustrates the distribution load growth by state that may trigger distribution upgrades during the IRP planning period. The forecasted distribution capacity deferral value averages approximately $26/kw-yr (2020$) for substations with a planned upgrade that can be deferred indefinitely. If distributed resource programs result in resources on a mix of substations that include medium or low value areas, the effective distribution capacity deferral value would be reduced.

Table N.3 - Forecasted Distribution Load Growth Above 90 Percent Planning Threshold (MW)

Year	CA	ID	OR	UT	WA	WY	Total
2021	0	15	24	151	13	3	206
2022	1	15	31	161	16	3	227
2023	1	16	40	198	16	3	274
2024	1	20	46	242	20	3	333
2025	2	23	63	272	26	20	405
2026	2	28	71	317	26	20	464
2027	2	28	77	339	28	25	499
2028	2	32	78	343	28	28	511
2029	2	34	83	385	28	28	559
2030	2	38	83	423	28	35	608
2031	2	38	84	437	32	52	645
2032	2	38	93	453	37	52	674
2033	2	38	96	465	40	57	699
2034	2	39	99	483	40	59	721
2035	2	39	99	506	40	61	747
2036	2	42	104	571	40	61	819
2037	2	43	107	577	40	75	845
2038	2	44	108	581	40	99	874
2039	2	50	112	589	43	99	895
2040	2	54	116	595	43	99	909

Generation Capacity

Background

To provide reliable service to customers, a utility must have sufficient resources in every hour to:

- Serve customer load, including losses and any unanticipated load increase.
- Hold operating reserves to meet NERC and WECC reliability standards, including contingency, regulation, and frequency response.
- Replace resources that are unavailable due to:
    - Forced and planned outages
    - Dry hydro conditions
    - Wind and solar conditions
    - Market conditions

PacifiCorp refers to "Generation Capacity" as the total quantity of resources necessary to reliably serve customers, after accounting for the items above. For the 2021 IRP, PacifiCorp identified a planning reserve margin of 13 percent over its hourly loads throughout the year. The planning reserve margin does not translate directly into either resources or need.

All resources contribute to a reliable portfolio, but they do so in ways that are not straightforward to measure and are dependent on the composition of the portfolio. Removing a resource from a portfolio will make that portfolio less reliable unless it is replaced with something else, ideally in a quantity that provides an equal capacity contribution and results in equivalent reliability. For more details on capacity contribution, please refer to Volume II, Appendix K (Capacity Contribution).

As a result, the most direct measurement of the generation capacity value of a resource is to build a portfolio that includes it and compare that portfolio to one without it. But even that analysis would identify more than just generation capacity value, as it would also include energy and operating reserve impacts related to both the resource being added and resources that were delayed or removed. This is an essential description of the steps used to develop portfolios in the IRP, and while powerful, the IRP models and tools do not lend themselves to ease of use, rapid turnaround, or the evaluation of small differences in portfolios.

As an alternative, a simplified approach to generation capacity value can be used when the resources being evaluated are small or similar to the proxy resource additions identified in the IRP preferred portfolio. The premise of the approach is that the IRP preferred portfolio resources represent the least-cost, least-risk path to reliably meet system load. The appropriate level of generation capacity value is inherently embedded in the IRP preferred portfolio resource costs, because those resources achieve the stated goal of reliable operation. Again, while it is difficult to identify exactly what portion of the resource cost should be considered generation capacity as opposed to energy or operating reserve value, the total resource cost is straightforward and known. The 2021 IRP preferred portfolio includes stand-alone four-hour lithium-ion battery storage resources starting in 2029. These resources have annual fixed costs (capital recovery and fixed operations and maintenance) of approximately $109/kw-yr in 2029. After netting out energy and operating reserve values as described above, the remainder is approximately $89/kw-yr for 2029. This represents the net cost of the battery's nameplate capacity. To put this on an equivalent footing with resources of different types, it can be converted to a net cost of "pure" capacity, by dividing by its capacity contribution. The summer capacity contribution for 4-hour duration storage is 74%, as discussed in Appendix K (Capacity Contribution). This would result in a 2029 cost of $115/kw-yr for "pure" summer capacity from four-hour lithium-ion storage.

While uncertainty remains in these generation capacity values, the uncertainty in the conclusions can be small to the extent a resource being evaluated provides largely the same services as the resource in the 2019 IRP. As a result, it is reasonable to compare the costs and benefits of energy storage resources that provide energy value, operating reserves, and charging during renewable resource over-supply to the costs and implicit benefits of energy storage resources in the IRP, which also provide those same services. To the extent the resources being evaluated vary significantly in characteristics or timing relative to the resources in the 2019 IRP preferred portfolio, a more thorough analysis using a production cost model would be necessary to ensure the relative benefits of preferred portfolio resources and a resource being evaluated are characterized accurately.

Part 2: Energy Storage Operating Parameters

This section discusses some of the key operating parameters associated with energy storage resources. Beyond just defining the basic concepts, it is important to recognize the specific ways in which these parameters are measured and ensure that any comparison of different technologies or proposals reports equivalent values. For example, many battery systems operate using direct current (DC) rather than the alternating current (AC) of the vast majority of the electrical grid. When charging or discharging from the grid, inverters must convert DC power to AC power, which creates losses that reduce the effective output when measured at the grid, rather than at the battery. To handle this distinction, PacifiCorp uses the AC measurement at the connection to the electrical grid for all parameters, as this aligns with the effective "generation input" of an energy storage resource. As previously discussed, an additional adjustment for line losses on the electrical grid may also be necessary, but that is dependent on the location and conditions on the electrical grid, rather than the energy storage resource.

- **Discharge capacity**: The maximum output of the energy storage system to the grid, on an AC-basis, measured in megawatts (MW). This is generally equivalent to nameplate capacity.
- **Storage capacity:** The maximum output of the energy storage system to the grid, on an AC-basis, when starting from fully charged, measured in megawatt-hours (MWh).
- **Hours of storage:** The length of time that an energy storage system can operate at its maximum discharge capacity, when starting from fully charged, measured in hours. Generally, the hours of storage will be equal to storage capacity divided by discharge capacity.
- **Charge capacity:** The maximum input from the grid to the energy storage system, on an AC-basis, measured in megawatts (MW).
- **Round-trip efficiency:** The output of the energy storage system to the grid, divided by the input from the grid necessary to achieve that level of output, stated as a percentage. A storage resource with eighty percent efficiency will output eight MWh when charged with ten MWh. If charge and discharge capacity are the same, losses result in a longer charging time. For instance, an energy storage system with four hours of storage, eighty percent efficiency, and identical charge and discharge capacity would require five hours to fully charge (4 hours of discharge divided by 80 percent discharge MWh per charge MWh).
- **State of charge:** This is a measure of how full a storage system is, calculated based on the maximum MWh of output at the current charge level, divided by the storage capacity when fully charged, and is stated as a percentage. One hundred percent state of charge indicates the storage system is full and can't store any additional energy, while zero percent state of charge indicates the storage system is empty and can't discharge any energy. As previously indicated, PacifiCorp's state of charge metric is based on output to the grid. As a result, the entire round-trip efficiency loss is applied during charging before reporting the state of charge. For example, a storage system with a ten MWh storage capacity and eighty percent efficiency would only have an eighty percent state of charge after ten MWh of charging had been completed, starting from empty.
- **Station service:** Round-trip efficiency is a measure of the losses from charging and discharging. Some energy storage systems also draw power for temperature control and other needs. This is typically drawn from the grid, rather than the energy storage resource.

Some energy storage technologies experience degradation of their operating parameters over time and based on use. The following parameters are used to quantify the effects of degradation.

- **Storage capacity degradation:** The primary impact of degradation is on storage capacity. Much of the degradation occurs as part of charge-discharge cycles, and can be measured as the degradation per thousand cycles. After one thousand cycles, a four-hour storage system might only be capable of storing 3.5 hours of output. Some storage resources also experience degradation that isn't tied to cycles, for instance based on differing state of charge levels or time.
- **Cycle life:** This is the total number of full charge and discharge cycles that energy storage equipment is rated for. Three thousand cycles is common for lithium-ion resources, but operating under harsh conditions can also cause the effective cycle count to decline faster. Once storage capacity has degraded by thirty percent degradation per cycle may accelerate.
- **Depth of discharge:** Operating at a very high or very low state of charge, particularly for an extended period of time, can cause more rapid degradation. This metric can be used to identify how particular operations impact the effective remaining cycle life.
- **Variable degradation cost:** Lithium-ion energy storage equipment is composed of a large number of battery modules, each of which experience degradation. These modules can be gradually replaced over time to maintain a more consistent storage capacity, or they can be replaced all at once when cycle limits are reached, at the expense of a reduced storage capacity in the interim. In either case, the replacement cost of storage equipment can be expressed per MWh of discharge, and accounted for as part of resource dispatch.

Part 3: Distributed Resource Configuration and Applications

This section described the potential benefits of different distributed resource siting and configuration options. Due to economies of scale, distributed resource solutions generally higher cost relative to utility-scale assets. For example, the 2021 IRP supply-side table shows that on a per kilowatt basis, the fixed costs for a fifty-megawatt, four-hour lithium-ion battery are roughly half that for a one-megawatt, four-hour battery. While these savings are appreciable, it should be noted that a fifteen-megawatt battery is small and can be considered modular relative to traditional resources such as a simple cycle combustion turbine. Many of PacifiCorp's distribution substations have capacity in excess of fifteen megawatts, such that a battery of that size could be feasible at the distribution level, with the potential for incremental benefits relative to the transmission-connected battery resources modeled as part of the 2019 IRP preferred portfolio. The most cost-effective locations for distributed resource deployment are likely to reflect a balance of local requirements and economies of scale.

Secondary Voltage

A distributed resource which is located downstream from the high voltage transmission grid will have a larger energy impact than its metered output would indicate, due to line losses. This is true for both charging and discharging. To the extent discharging is aligned with periods with higher load, and charging is aligned with periods with lower load, the benefits will be proportionately higher. For example, the marginal primary voltage losses for Oregon are estimated at 9.5 percent on average across the year. Savings based on primary losses would be appropriate to apply to a resource connected at the secondary voltage level so long as it is not generating exports to the higher voltage system, as losses would still occur within that level, but would be reduced due to lower deliveries across the higher voltage system. When the hourly loss profile is applied to the hourly market prices used to calculate the energy values described in Part 1, the result is 16 percent higher for a four-hour lithium-ion battery. Much of the incremental benefit is due to high loss rates in summer and winter peak load months, when prices are relatively high. For lithium-ion batteries, there is also an incremental benefit related to variable degradation costs. While the effect of losses makes the battery appear larger from a system benefits perspective, it discharges the same amount, so the variable cost component doesn't scale with losses, creating an additional benefit that is captured in this energy margin.

In addition to incremental energy value, resources connected at primary or secondary voltage will also have a proportionately higher generation capacity value. In the example for Oregon above, this amounts to a roughly 11 percent increase in effective capacity contribution based on avoided primary losses.

T&D Capacity Deferral

As indicated in the grid services section, distributed resources can allow for the deferral of upgrades by reducing the peak loading of the transmission and distribution system elements serving their area. In order for deferral to be achieved, a distributed resource must reliably reduce load under peak conditions. However, the timing of peak conditions for a given area is likely to vary from the peak conditions for the system as a whole. As a result, the energy or generation capacity value of energy-limited resources used for a T&D capacity deferral application are likely to be reduced. For instance, when energy-limited resources are reserved for local area requirements they would not be available for system reliability events or a period of high energy prices.

Combined Solar and Storage

Under current tax law, solar resources can qualify for an increased federal investment tax credit (ITC) if they come online prior to the end of 2025. Thereafter, solar resources will continue to qualify for a ten percent ITC. Storage that is constructed in combination with a solar resource and which is charged using that solar resource for the first five years of operation qualifies for the same ITC as the solar resource. This reduces the cost of storage combined with solar relative to stand-alone storage. There are also construction and operational efficiencies that can further improve the economics of combined storage and solar assets, including shared construction crews, inverters, property, and maintenance.

As a result of the items benefits above, combining storage with solar resources provides greater benefits than portfolios that included new solar resources without storage. In the 2021 IRP, storage resources that are combined with solar are sized equivalent to 100 percent of the solar nameplate and have four hours of storage. These sizing parameters will evolve as PacifiCorp goes out to procure specific resources, based on both the costs and effective capabilities of different configurations.

Cost-Effectiveness Results

Table N.4 provides details on the year-by-year benefits of various lithium-ion battery applications.

Since a stand-alone battery is included in the preferred portfolio starting in 2029, it is assumed to be cost effective and providing benefits equal to its costs starting in that year. Additional benefits applicable to distributed resources are also identified.

Table N.4 – Energy Storage Applications - Annual Benefits Stream

					Potential Benefits from Distributed Resources				
$/kw-yr	Stand-alone Li-Ion 4hr Fixed Cost	Energy Value	Operating Reserve	Utility-scale Resource	Primary Losses Energy	Primary Losses Gen Capacity	Total Primary Losses	T&D Deferral	Primary Losses + T&D Deferral
2029	109.22	9.25	11.38	**109.22**	0.51	5.30	**115.03**	30.91	**145.94**
2030	111.21	12.85	11.59	**111.21**	0.71	5.19	**117.12**	31.58	**148.69**
2031	113.40	13.75	2.42	**113.40**	0.76	5.82	**119.98**	32.26	**152.24**
2032	115.73	17.57	4.08	**115.73**	0.98	5.63	**122.34**	32.95	**155.29**
2033	118.11	18.60	1.36	**118.11**	1.03	5.87	**125.02**	33.66	**158.68**
2034	120.54	19.08	1.28	**120.54**	1.06	5.99	**127.59**	34.39	**161.98**
2035	123.02	21.25	1.40	**123.02**	1.18	6.01	**130.21**	35.13	**165.34**
2036	125.56	35.96	1.62	**125.56**	2.00	5.26	**132.82**	35.88	**168.70**
2037	128.14	16.52	0.54	**128.14**	0.92	6.65	**135.71**	36.66	**172.37**
2038	130.79	112.38	0.59	**130.79**	6.24	1.07	**138.10**	37.45	**175.54**
2039	133.49	81.42	1.06	**133.49**	4.52	3.05	**141.06**	38.25	**179.32**
2040	136.24	87.26	1.23	**136.24**	4.85	2.86	**143.95**	39.08	**183.03**

APPENDIX O – WASHINGTON CLEAN ENERGY ACTION PLAN

Introduction

The Clean Energy Transformation Act (CETA) was passed by the Washington State Legislature and signed into law by Governor Jay Inslee in May 2019. The legislation combines directives for utilities to pursue a clean energy future with assurances that benefits from a transformation to clean power are equitably distributed among all Washingtonians.

The Washington Utilities and Transportation Commission began rulemakings to implement CETA in June 2019, and the first phase concluded in December 2020. As directed by the legislation and the new CETA rules, Washington electric utilities must file the following long-term planning documents:

Clean Energy Action Plan: The Clean Energy Action Plan (CEAP) is a ten-year planning document that is derived from the IRP and included as an appendix to the IRP. The CEAP provides a Washington-specific view of how PacifiCorp is planning for a clean and equitable energy future that complies with CETA.

Integrated Resource Plan: The IRP is a comprehensive decision support tool and roadmap for meeting the company's objective of providing reliable and least-cost electric service to its customers. The plan is developed through open, transparent and extensive public involvement from state utility commission staff, state agencies, customer and industry advocacy groups, project developers, and other stakeholders.

The key elements of the IRP include: an assessment of resource need, focusing on the first 10 years of a 20-year planning period; the preferred portfolio of supply-side and demand-side resources to meet this need; and an action plan that identifies the steps that will be taken over the next two-to-four years to implement the plan.

Clean Energy Implementation Plan: The Clean Energy Implementation Plan (CEIP) is a plan that lists the specific actions PacifiCorp will take over the next four years to move toward the 2030 and 2045 clean energy directives. PacifiCorp's first CEIP will be filed in October 2021.

The CEAP included in the 2021 IRP provides a Washington-specific roadmap of how PacifiCorp is planning for a clean and equitable energy future relative to the requirements of CETA.

Part 1: PacifiCorp in Washington

PacifiCorp is a multi-jurisdictional, vertically integrated utility that serves nearly two million customers in six western states: California, Idaho, Oregon, Utah, Washington, and Wyoming. In Washington, PacifiCorp serves approximately 137,000 customers throughout Yakima, Walla Walla, Columbia, Benton, Cowlitz, and Garfield Counties. The company's generation and transmission systems span the west and connect customers to safe, reliable, affordable, and increasingly renewable electricity. Our integrated transmission system connects thermal, hydroelectric, wind, solar, and geothermal generating facilities with markets and loads. The diversity of this integrated system benefits all of PacifiCorp's customers in all six states. PacifiCorp owns approximately 11,500 megawatts (MW) of generating capacity and about 16,500 miles of transmission lines.

PacifiCorp's large regional footprint enables delivery of low-cost generation from some of the best wind and solar sites in the country reducing power costs and emissions. PacifiCorp is proud to operate one of the lowest-cost systems in the country, and we remain actively engaged in finding ways to leverage the benefits of geographic diversity for our customers as we develop and implement plans to deliver the targets set forth in CETA.

Over the past 13 years, PacifiCorp has successfully reduced its greenhouse gas emissions and improved reliability while simultaneously delivering energy cost savings to our customers. The company has achieved these results by collaborating with others, and through the visionary and collaborative efforts of our own generation, transmission, information technology and energy supply management teams, PacifiCorp has been a key player in the creation of an open and connected Western grid.

In 2014, PacifiCorp pioneered the Western Energy Imbalance Market (EIM) in partnership with the California Independent System Operator. This innovative market allows utilities across the West to access the lowest-cost energy available in near real time, making it easy for zero-fuel-cost renewable energy to go where it is needed. If excess solar energy in California, excess wind from Wyoming or hydropower from Washington and Oregon is available, PacifiCorp is positioned to harness it and transport it instantly across the company's 16,500-mile grid.

PacifiCorp's Energy Vision 2020 initiative accelerated that commitment to greenhouse gas reduction, adding 1,150 MW of new wind projects, and repowering our existing wind resources. In total, Energy Vision 2020 projects are able to power the annual energy needs of approximately 400,000 homes, in addition to creating hundreds of construction jobs and adding millions in tax revenue to rural economies.

PacifiCorp is also proud to be involved in the communities the company serves. In Washington, for over 20 years, PacifiCorp has hosted the Merwin Special Kids Day. The Merwin Special Kids Day is a unique annual event held at the company's Merwin hydro generation facility that provides kids, that would not otherwise have the opportunity to go fishing, an opportunity to visit the Merwin facility and fish for trout. More than 100 kids and their families attended the 2019 event. PacifiCorp's employees and families look forward to hosting this event each year.

In June 2019, PacifiCorp hosted an energy fair in Yakima and hosted an energy education booth at the Walla Walla Sweet Onion Festival. The participation at these events allowed PacifiCorp to provide information about energy efficiency offerings, local reliability upgrades, account services, renewable energy options, electric vehicle charging station grants, and an electric vehicle ride and drive opportunity.

PacifiCorp is also proud to have completed light emitting diode (LED) street lighting upgrades for 18 communities in Washington. The project was a partnership with the Washington State Transportation Improvement Board (TIB) and Pacific Power's Wattsmart program. The project resulted in the 18 cities saving an average of 30% on their street light costs. Walla Walla and Yakima did not qualify for the TIB program, but Pacific Power—using the Wattsmart program incentives—was able to partner with the two communities to upgrade their streetlights. This means every community in Pacific Power's Washington service territory has been upgraded to LED.

Part 2: Resource Adequacy

PacifiCorp's CEAP is planning toward a future in Washington that balances a rapid transition to renewable and non-emitting energy as directed under CETA, with our continued commitment to ensure that we are serving customers affordably, safely, and reliably. To meet reliability standards in a future that includes an increasing number and type of variable resources, PacifiCorp has carefully analyzed the way our programs, generation resources, customer load obligations, cost-effective conservation potential fit together to ensure reliability.

The company's long-term load forecasts (both energy and coincident peak load) for each state and for the system as a whole are summarized in Volume I, Chapter 6 (Load and Resource Balance) as well as in Appendix A (Load Forecast Details). The summary-level system coincident peak is presented first, followed by a profile of PacifiCorp's existing resources. Finally, load and resource balances for capacity and energy are presented. These balances are composed of a year-by-year comparison of projected loads against the existing resource base, with and without available FOTs, assumed coal unit retirements and incremental new energy efficiency savings from the 2021 IRP preferred portfolio, before adding new generating resources.

Resource Portfolio Development

As discussed in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach), PacifiCorp uses the Plexos LT model to produce resource portfolios with sufficient capacity to meet all load and operating reserves requirements over the 20-year study horizon appropriate to achievable granularity. Each of these portfolios is uniquely characterized by variables on PacifiCorp's system, including type, timing, location, and resources needed to achieve reliable operation. The portfolio modeling and selection process ultimately leads to an optimized, lowest reasonable cost six-state portfolio to serve PacifiCorp's customers.

These resource portfolios reflect a combination of planning assumptions such as resource retirements, CO_2 prices (also applicable to CO_2 equivalent emissions, or "CO_2e"), wholesale power and natural gas prices, load growth net of assumed private generation penetration levels, cost and performance attributes of potential transmission upgrades, and new and existing resource cost and performance data, including assumptions for new supply-side resources and incremental demand-side management (DSM) resources. Changes to these input variables cause changes to the resource mix, which influences system costs and risks. The Plexos LT model is also used to consider the retirement of coal endogenously—a methodological improvement that is new to the 2021 IRP.

In its 2021 IRP, PacifiCorp applies a capacity reserve margin (CRM) to ensure resource adequacy, modeled minimum 13 percent requirement calculated at each topology location carrying load. Additionally, the 2021 IRP will directly model operating reserve requirements in expansion plan model runs which ensures that expansion resources selected to meet CRM requirements will also meet operating reserve requirements. Taken together, these reliability requirements ensure that PacifiCorp has sufficient resources to meet load in all periods, recognizing the uncertainty for load fluctuation and extreme weather conditions, fluctuation of variable generation resources, a possibility for unplanned resource outages, and reliability requirements to carry sufficient contingency and regulating reserves.

PacifiCorp's study period to select the preferred portfolio in the IRP is a 20-year period beginning January 1, 2021 and ending December 31, 2040. The CEAP represents an allocation of the optimized portfolio to Washington over a ten-year horizon ending in 2030. The following resources were considered as part of the long-term expansion model at the system level to ensure resource adequacy

Dispatchable Thermal Resources:
These resources include dispatch costs for fuel, non-fuel VOM, and the costs of greenhouse emissions, as applicable. Thermal resources are dispatched by least-cost merit order. The power produced by these resources can be used to meet load or to make off-system sales at times when resource dispatch costs fall below market prices. Conversely, at times when dispatch costs exceed market prices, off-system purchases can displace dispatchable thermal generation to minimize system energy costs. Dispatch of thermal resources reflects any applicable transmission constraints connecting generating resources with both load and market locations as defined in the transmission topology of the model.

Front Office Transactions:
FOTs represent short-term firm market purchases for physical delivery of power. PacifiCorp is active in the western wholesale power markets and routinely makes short-term firm market purchases for physical deliveries on a forward basis (i.e., prompt month forward, balance of month, day-ahead, and hour-ahead). These transactions are used to balance PacifiCorp's system as market and system conditions become more certain when the time between an effective transaction date and real time delivery is reduced.

Demand-Side Management:
Energy efficiency resources are characterized with supply curves that represent achievable technical potential of the resource by state, by year, and by measures specific to PacifiCorp's service territory. For modeling purposes, these data are aggregated into cost bundles. Each cost bundle of the energy efficiency supply curves specifies the aggregate

energy savings profile of all measures included within the cost bundle. Each cost bundle has both a summer and winter capacity contribution based on aggregate energy savings during on-peak hours in July and December aligning with periods where PacifiCorp is most likely to exhibit capacity shortfalls.

Demand response resources, representing direct load control capacity resources, are also characterized with supply curves representing achievable technical potential by state and by year for specific direct load control program categories (i.e., air conditioning, irrigation, and commercial curtailment). Operating characteristics include variables such as total number of hours per year and hours per event that the demand response resource is available.

Wind and Solar Resources:
Certain wind and solar resources are dispatchable by the model up to fixed energy profiles that vary by day and month. The fixed energy profiles for wind and solar resources represents the expected generation levels in which half of the time actual generation would fall below expected levels, and half of the time actual generation would be above expected levels assuming no curtailments.

The contribution of wind and solar resources, determined by forecast profiles, determine the ability for these resources to reliably meet demand over time. The use of resource availability to meet requirements in all periods allows the model to endogenously account for declining capacity contribution due to the increasing penetration of resources with similar dispatch patterns.

Preferred Portfolio Results

PacifiCorp's preferred portfolio reflects the company's ongoing vision in which clean energy from across the West powers jobs and innovation. This bold vision took shape in the 2017 and 2019 IRPs, in which an ambitious path was outlined to substantially increase renewable energy capacity, evolving the existing portfolio, and connecting supply with demand through an expanded, modernized transmission system. The 2021 preferred portfolio builds on that vision and was evaluated against the requirements of CETA. The 2021 preferred portfolio:

- **Continues the transition to a low-carbon portfolio:**
    - Begin the process of retiring or divesting Colstrip Units 3 and 4 in Colstrip, Montana
    - Begin the process of a coal-to-gas peaker conversion of Jim Bridger Units 1 and 2 in Rock Springs, Wyoming
    - Begin the process of retirement or sale of Naughton Units 1 and 2

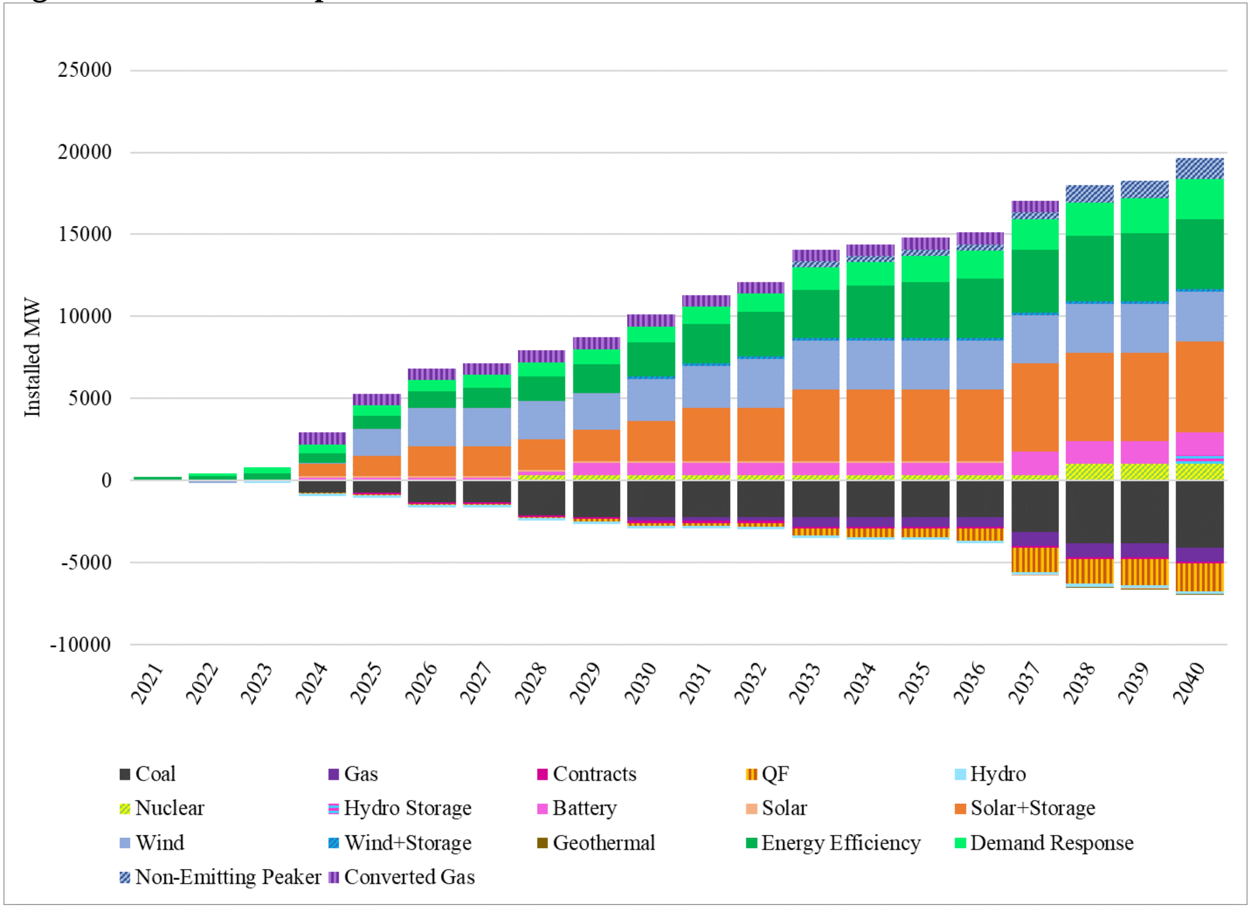
- **Continues growth into a grid powered by clean energy (incremental to projects already online and projects with executed agreements that will come online through 2023)**:

- 4,290 MW of incremental savings through energy efficiency programs
- 5,628 MW of new solar resources (most paired with storage)
- 3,628 MW of new wind resources
- 6,181 MW of storage resources including battery storage co-located with solar, standalone battery storage and pumped hydro storage resources
- 2,448 MW of direct load control programs
- 500 MW of advanced nuclear (the Natrium TM reactor demonstration project) in 2028, with an additional 1,000 MW of advanced nuclear over the long term

- **Connects and optimizes the diverse, clean resources across the West with a strengthened and modernized transmission network that ensures resilient service, reduces costs, and creates maximum opportunities for our communities to thrive (incremental to projects already online)**:
  - 416 miles of new transmission from the new Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah (Energy Gateway South)
  - 59 miles of new transmission from the Shirley Basin substation in southeastern Wyoming to the Windstar substation near Glenrock, Wyoming (Energy Gateway West Sub-Segment D.1)
  - 290 miles of new transmission from the Boardman substation in north central Oregon to the Hemingway substation in south central Idaho

PacifiCorp's IRP preferred portfolio selections are summarized in Figure O.1.

Figure O.1 – PacifiCorp 2021 IRP Preferred Portfolio



The methodology behind PacifiCorp's preferred portfolio selection – as well as additional detail on the supply-side and demand-side resources selected as part of the portfolio – is detailed in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach) and Chapter 9 (Modeling and Portfolio Selection).

PacifiCorp's IRP preferred portfolio is optimized to serve the company's six-state service area on a lowest reasonable cost basis. As part of portfolio construction, PacifiCorp takes into account planning reserve margin and resource adequacy considerations, as well as the availability of regional generation and transmission. Additional detail on resource adequacy and the availability of regional resources can be found in Volume I, Chapter 5 (Reliability and Resiliency).

In compliance with WAC 480-100-620(12)(i), the social cost of greenhouse gas (SCGHG) was considered as part of the selection of PacifiCorp's preferred portfolio and was the basis of multiple price-policy scenarios and other required and requested sensitivities. As the SCGHG was an important part of considering and ultimately selecting a lowest reasonable cost optimized portfolio, the impacts of SCGHG on portfolio modeling are included in the Washington allocation of the portfolio discussed in this appendix. Additional detail on how SCGHG was considered in PacifiCorp's portfolio modeling can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach).

PacifiCorp preferred portfolio 2021-2030

Based on the resources in P02-MM-CETA PacifiCorp's generation portfolio will substantially increase renewable generation and will add new non-emitting resources. Coal-fueled generation will be removed from Washington rates by the end of 2023. Chehalis Generation Station (Chehalis) is projected to be the only thermal resource serving Washington customers after 2024 and will retire in 2043.

Under the preferred portfolio the share of renewable and non-carbon-emitting resources as a percentage of Washington retail load will have increased from 28% in 2021, to around 81% in 2030. Additionally, PacifiCorp is on track to meet the 100% renewable and non-emitting standard in Washington by 2045.

Coal-fueled resources

Washington is currently served by two coal-fired facilities within PacifiCorp's resource portfolio: Colstrip Unit 4 in Colstrip, Montana, and Jim Bridger Units 1 and 2 in Point of Rocks, Wyoming. The allocation of resources to Washington – in accordance with WAC 480-100-610(1) – will no longer include both resources by December 31, 2023.

Following the removal of these resources from Washington's allocation of energy, PacifiCorp will pursue the retirement or divestiture of Colstrip from the company's portfolio by the end of 2025. The company will begin steps to convert Jim Bridger Units 1 and 2 from coal-fueled to natural gas fueled; PacifiCorp does not anticipate allocating any of the converted Jim Bridger units to Washington.

Other thermal resources

PacifiCorp's Washington allocation of energy currently includes generation from the Chehalis Generating Station (Chehalis) – a natural-gas fired resource in Chehalis, Washington – and from the Hermiston Generating Station (Hermiston) – a natural-gas fired resource in Hermiston, Oregon. On an energy basis, Hermiston currently serves approximately one third of the gas-fueled power serving Washington. Hermiston will be removed from Washington's allocation of electricity by the end of 2023.

Chehalis is currently forecast to serve Washington customers through the end of the IRP study period and will be retired at the technical end-of-life in 2043. Following the removal of coal-fueled resources from Washington's allocation of electricity at the end of 2023, Chehalis will be the only thermal unit serving Washington customers until its retirement.

Non-emitting resources

PacifiCorp's non-emitting resources serving Washington currently consists of generation from 35 hydroelectric facilities throughout the company's six-state service area.

PacifiCorp's preferred portfolio also includes nuclear. The portfolio selects a 500 MW advanced nuclear Natrium™ demonstration project to come online by summer 2028. This resource will serve as an additional non-emitting capacity resource.

Renewable Resources

The 2021 IRP preferred portfolio includes 1,302 MW of new solar by the end of 2024 and 1,902 MW by the end of 2026. Through 2040, more than 5,600 MW of new solar is scheduled to come online system wide. PacifiCorp's 2021 IRP preferred portfolio also includes 1,792 MW of new wind generation resulting from the 2020 All-Source RFP and the acquisition and repowering of Rock River I (49 MW) and Foote Creek II-IV (43 MW). Through the end of 2026, the 2021 IRP preferred portfolio includes an additional 745 MW of new wind and more than 3,700 MW of new wind by 2040.

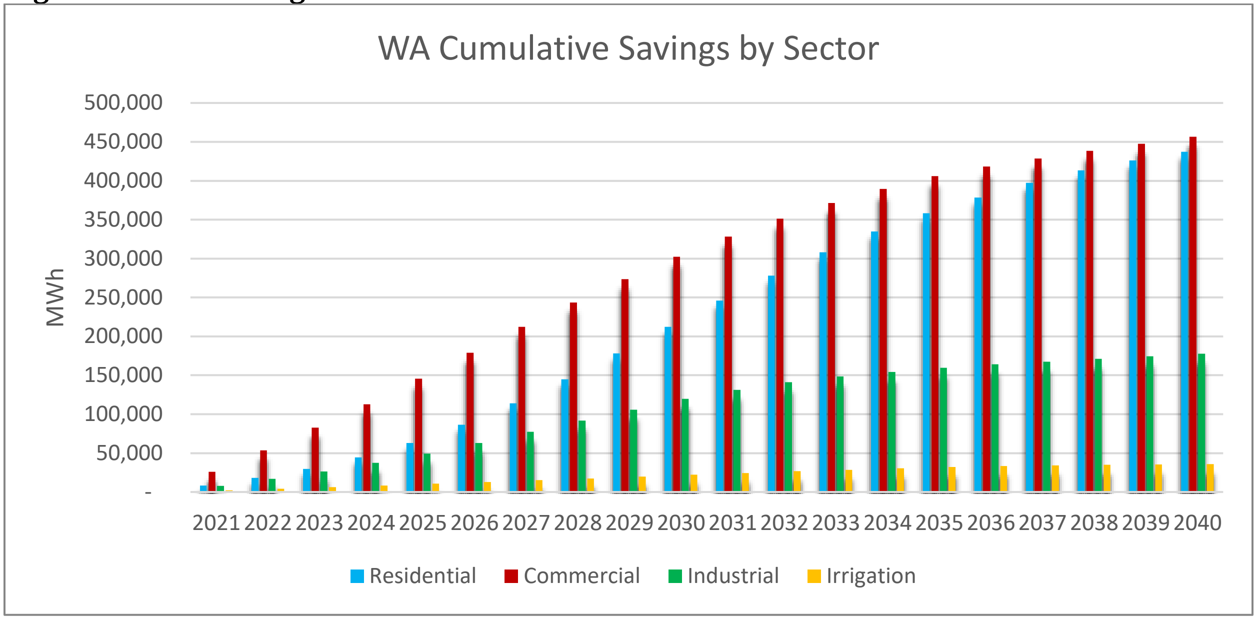
Additionally, during the portfolio development process, upon evaluation relative to the 2030 CETA target, a shortfall of roughly 69 MW of annual capacity was identified in 2030 (the highest shortfall year), with significantly smaller shortfalls identified in the years between 2030-2033. Under a four-year compliance window for the time period 2030 – 2033, an average annual shortfall of 49 MW was identified. This shortfall is addressed with a Washington-situs assigned 160 MW wind and solar resource co-located with storage located in Yakima, Washington. A further discussion of how the preferred portfolio was evaluated relative to the requirements of CETA can be found in Volume I, Chapter 9 (Modeling and Portfolio Selection).

Conservation Potential

New cost-effective energy efficiency measures and programs are among the new resource selections that are present in every portfolio described in the process above. These resources are first identified through the development of a conservation potential assessment (CPA) which identifies the magnitude and cost of all technically achievable energy savings opportunities in PacifiCorp's service territory over the next 20 years. Several measures include quantified non energy impacts netted against measure cost. Examples include health benefits from avoided woodsmoke with installation of ductless heat pumps, operations and maintenance cost savings with new lighting, and water savings for measures which conserve water use as well as electricity use. For the past several IRP cycles, PacifiCorp has contracted with Applied Energy Group (AEG) to conduct this assessment. A comprehensive description of the study methodology, underlying assumptions, and results can be found on PacifiCorp's website[1]. Figure O.2 shows cumulative technical achievable potential results from the CPA for the Washington service territory.

[1] Available online at https://www.pacificorp.com/energy/integrated-resource-plan/support.html

Figure O.2 – Washington CPA Technical Achievable Potential



The study results in over 3,000 individual efficiency measures which are then bundled into 27 groups for each of PacifiCorp's six states. In past years, these groups were characterized only by the total levelized cost of each measure. For the 2021 IRP, a new bundling approach based on net value of efficiency resources will be employed as described at the January 2021 public-input meeting.

The output from the CPA serves as an input to the Plexos model which selects the optimal mix of resources from the defined bundles to provide system adequacy in a least cost least risk manner. The conservation resources which are selected in the preferred portfolio become the cost-effective conservation potential.

Demand Response and Load Management Programs

Cost-effective demand response and load management resources are identified and selected in a manner similar to conservation resources. The scope of the CPA also includes identification of the technical potential for direct load control (DLC) demand response opportunities and for potential new pricing programs. The methodology and all underlying assumptions and results for these resources can also be found on PacifiCorp's website.

Direct load control resources are differentiated by customer, technology, and duration. Sustained duration resources are available for more than 20 minutes while short duration reflects load which can be curtailed in greater quantity but for shorter duration such as for frequency response over 5-minute increments where the customer is less likely to be impacted by the disruption.

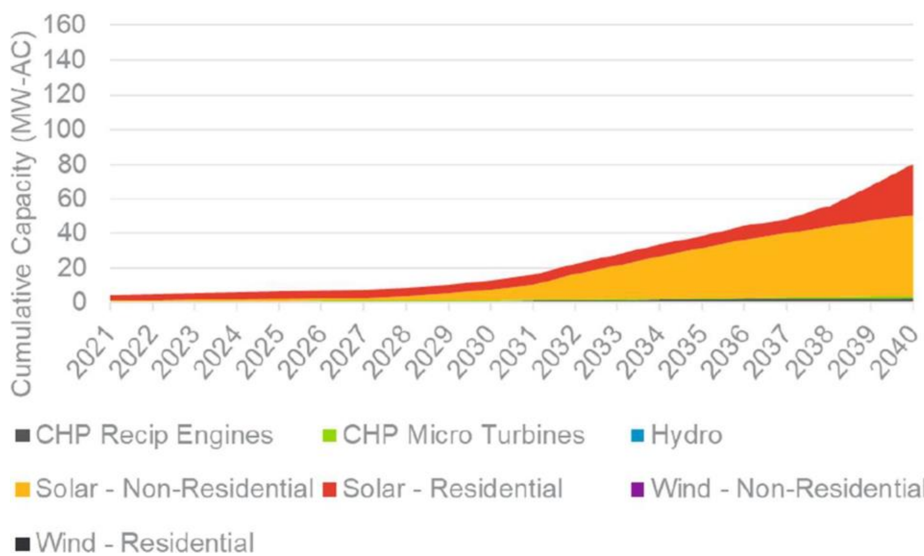
The amount and cost of load curtailment or shift is characterized by customer type and type of end use that is being controlled. The technical achievable potential is input to the IRP model as a resource option to be selected to meet system adequacy. Demand response selections by the model are cost effective potential to be acquired as a part of the preferred portfolio.

Pricing programs include time-of-use rates, critical-peak pricing and other behavioral pricing tools. The third focus of the CPA is to quantify the technical potential and magnitude of demand impacts possible through these pricing designs. The results are used to inform future rate design concepts that are proposed with rate cases but the IRP model is not used to determine the type and amount of pricing programs as a part of the preferred portfolio. This is because all pricing programs are designed to be cost effective to the system but may not be cost effective for the individual customer to select. Therefore, setting targets for programs that only benefit the utility system but not customers is not appropriate for the IRP but is analyzed and designed through other stakeholder and regulatory processes.

Distributed Energy Resources

Distributed energy resources include energy conservation, demand response and load management, and distributed generation. Energy conservation and demand response and load management are characterized in the CPA as described above. New customer-sited generation is forecasted within the Private Generation Long Term Resource Assessment, which will be included as an appendix to the 2021 IRP). This assessment was conducted by Guidehouse Consulting for all states and for each distributed generation resource type including solar PV, small scale wind, small scale hydro, reciprocating engines and micro-turbines. The resource costs and state specific policies and incentives are integrated in the forecast of customer adoption of these resources across low, base, and high case scenarios. The base case results are netted against each state's load forecast. Washington private generation assumptions are shown in Figure O.3.

Figure O.3 – Washington Private Generation Assumptions



Transmission

PacifiCorp uses a transmission topology that captures major load centers, generation resources, and market hubs interconnected via firm transmission paths. Transfer capabilities across transmission paths are based upon the firm transmission rights of PacifiCorp's merchant function, including transmission rights from PacifiCorp's transmission function and other regional transmission providers.

In support of the significant renewable resource additions identified in the 2021 preferred portfolio, PacifiCorp has identified a number of transmissions and upgrades that will reinforce existing transmission paths, allow for increased east-west transfer capability, and will support the interconnection of new renewables. A summary of PacifiCorp's identified transmission additions is shown in Figure O.4 below:

Figure O.4 - Transmission Projects Included in the 2021 IRP Preferred Portfolio

Year	Resource(s)	From	To	Description
2025	1,641 MW RFP Wind (2025)	Aeolus WY	Clover	Enables 1,930 MW of interconnection with 1700 MW of TTC: Energy Gateway South
2026	615 MW Wind (2026)	Within Willamette Valley OR Transmission Area		Enables 615 MW of interconnection: Albany OR area reinforcement
2026	130 MW Wind (2026) 450 MW Wind (2032) 650 MW Battery (2037)	Portland North Coast	Willamette Valley Southern Oregon	Enables 2080 MW of interconnection with 1950 MW TTC; Portland Coast area reinforcement, Willamette Valley and Southerm Oregon
2026	600 MW Solar+Storage (2026)	Borah-Populous	Hemingway	Enables 600 MW of interconnection with 600 MW of TTC: B2H Boardman-Hemingway
2028	41 MW Solar+Storage (2028) 377 MW Solar+Storage (2030)	Within Southern OR Transmission Area		Enables 460 MW of interconnection: Medford area reinforcement
2030	160 MW Solar+Wind+Storage (2030) 20 MW Solar+Storage (2030)	Yakima WA Transmission Area		Enables 180 MW of interconnection: Yakima local area reinforcement
2031	820 MW Solar+Storage (2031) 206 MW Non-Emitting Peaker (2033)	Northern UT Transmission Area		Enables 1040 MW of interconnection: Northern UT 345 kV reinforcement
2033	400 MW Non-Emitting Peaker (2033) 1100 MW Solar+Storage (2033)	Southern UT	Northern UT	Enables 1500 MW of interconnection with 800 MW TTC: Spanish Fork - Mercer 345 kV; New Emery – Clover 345 kV
2040	156 MW Solar+Storage (2040) 500 MW Pumped Storage (2040)	Central OR	Willamette Valley	Enables 980 MW of interconnection with 1500 MW of TTC
2028*	500 MW Adv Nuclear (2028)	Southwest Wyoming Transmission Area		Reclaimed transmission upon retirement of Naughton 1 & 2
2029*	549 MW Battery (2029)	Eastern Wyoming Transmission Area		Reclaimed transmission upon retirement of Dave Johnston Plant
2037	909 MW Solar+Storage (2037)	Southern Utah Transmission Area		Reclaimed transmission upon retirement of Huntington 1 & 2
2038	412 MW Non-Emitting Peaker (2038) 1000 MW Adv Nuclear (2038)	Bridger WY Transmission Area		Reclaimed transmission upon retirement of Jim Bridger Plant
2040	206 MW Non-Emitting Peaker (2040) 60 MW Wind (2040)	Eastern Wyoming Transmission Area		Reclaimed transmission upon retirement of Wyodak

Part 3: Working Toward an Energy Future that Benefits All Customers

WAC 480-100-610(4)(c) and WAC 480-100-620(12) direct PacifiCorp to ensure that all customers are benefiting from the transition to clean energy by:

(1) describing the specific actions the utility will take to equitably distribute benefits and reduce burdens for highly impacted communities (HICs) and vulnerable populations;

(2) estimating the degree to which such benefits will be equitably distributed, and burdens reduced over the CEAP's ten-year horizon; and

(3) describing how the specific actions are consistent with its long-term strategy.
To comply with these directives, PacifiCorp plans to conduct a multi-step stakeholder engagement process that will rely heavily on public participation and community input.

This section represents the first step in that effort. To support future stakeholder engagement, it:

1. Identifies highly impacted communities within the two main population centers of PacifiCorp's Washington service territory: Yakima and Walla Walla, drawing from DOH's Washington Tracking Network (WTN) Environmental Health Disparities map;

2. Discusses the historic and anticipated non-energy and energy-related burdens these HICs face;

3. Describes existing programs available to these HICs and possible benefits to these communities from the transition to clean energy.

Identifying Highly Impacted Communities

PacifiCorp's service area in Washington can be categorized into two distinct population centers: Yakima and the surrounding area, and Walla Walla and the surrounding area. In total, PacifiCorp's Washington service area covers or partially covers sixty-one census tracts. PacifiCorp's service area in the Yakima and the surrounding area covers or partially covers forty-seven separate census tracts, while Walla Walla and the surrounding area covers or partially covers fourteen census tracts. Based on information from the U.S Census Bureau's, American Community Survey the population of these sixty-one census tracts is 259,228.

- The Washington Department of Health (DOH) defines a HIC as a census tract that meets at least one of the following two criteria:
  - The census tract is covered or partially covered by "Indian Country" as defined and designated by statue (RCW 19.405.020), or

- The census tract ranks a nine or ten on the WTN Environmental Health Disparities Map, as designated by the Washington DOH.

Through a collaborative effort, the DOH's Washington Tracking Network (WTN) developed a ranking of environmental, health and socioeconomic themes and measures for each census tract throughout the state using deciles (1 decile = 10%). Each decile represents 10% of the values in the data set. As an example of how to interpret the WTN rankings, a census tract with a rank of nine for poverty would mean that 10% of other census tracts throughout the state have a higher proportion of their population living below the poverty level, while 80% of census tracts throughout the state have a lower proportion of their population living below the poverty level.

To determine the presence of HICs, PacifiCorp relied on geospatial analysis of WTN data for Tribal Lands, Environmental Health Disparities (EHD), Environmental Exposures, Environmental Effects, Socioeconomic Factors and Sensitive Populations. Additional detail on these themes and measures are provided below.

- **Indian Country:** Except as otherwise provided in sections 1154 and 1156 of 18 US Code, the term "Indian country", as used in 18 US Code Section 1151 and RCW 19.405.020, means (a) all land within the limits of any Indian reservation under the jurisdiction of the United States Government, notwithstanding the issuance of any patent, and, including rights-of-way running through the reservation, (b) all dependent Indian communities within the borders of the United States whether within the original or subsequently acquired territory thereof, and whether within or without the limits of a state, and (c) all Indian allotments, the Indian titles to which have not been extinguished, including rights-of-way running through the same.

- **Environmental Health Disparities (EHD):** The DOH uses the EHD data to designate highly impacted communities under the CETA-Cumulative Impact Analysis (CIA). It is the overall ranking of each of the nineteen WTN measures within the EHD, which are grouped into the following four themes:

- **Environmental Exposures:** includes Nitrous-Oxide diesel emissions (annual tons/Km2), ozone concentration, PM 2.5 concentration, populations near heavy-traffic roadways, and toxic releases from facilities

- **Environmental Effects:** which includes lead risk from housing, proximity to hazardous waste treatment and disposal facilities, proximity to national priorities list facilities (superfund sites), proximity to risk management plan facilities, and wastewater discharge

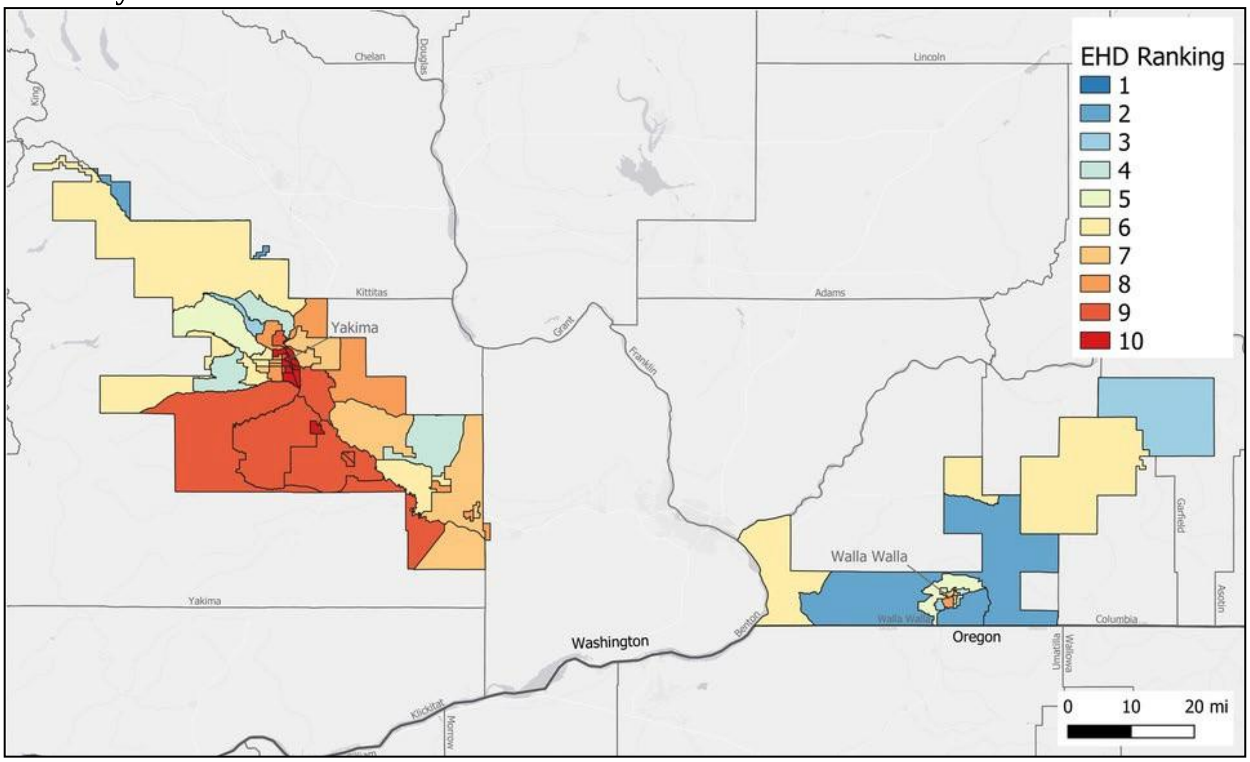
- **Socioeconomic factors:** including limited English, no high school diploma, race/ethnicity, population living in poverty, transportation expense, unaffordable housing, and unemployed

- **Sensitive Populations:** includes deaths from cardiovascular disease and low birthweight

Pacific Power Territory Specific Mapping of WTN Data by Census Tract

This section provides a geospatial analysis of communities within PacifiCorp's Washington service territory. Further, this analysis also incorporates DOH rankings for communities throughout the territory, with discussion focused on HICs with a ranking of 9 or greater.

Figure O.5 – WTN Data – Environmental Health Disparities (Overall) in Pacific Power Territory



Location	Count of WTN 9/10 Scoring Census Tracts
Environmental Health Disparities (EHD)	
Yakima	19
Walla Walla	0

Within the Yakima area, 19 census tracts have an Environmental Health Disparities ranking of 9 or greater. The Walla Walla area includes no census tracts with an Environmental Health Disparities ranking of 9 or greater. Additional information on Environmental Health Disparities ranking in the Washington service territory are provided below.

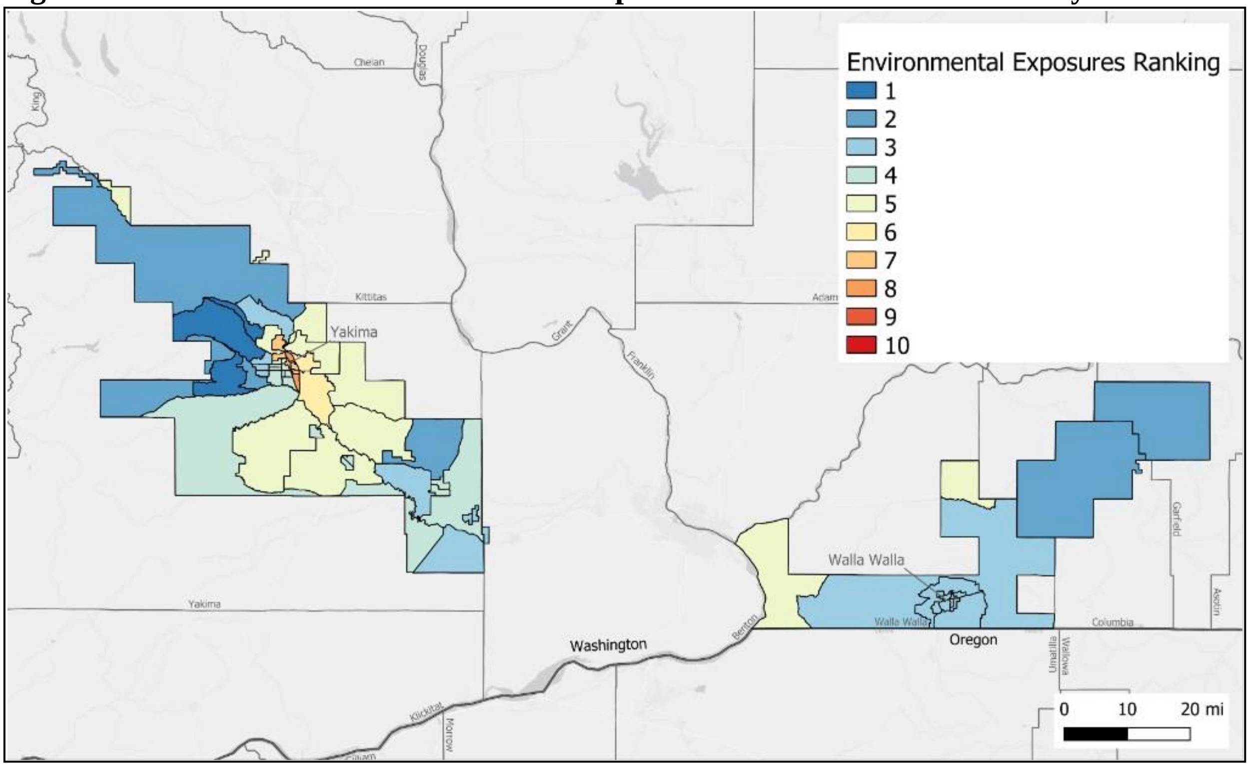
Yakima and Surrounding Area

The Yakima area includes 19 census tracts (40.4%) with an Environmental Health Disparities ranking of 9 or greater, with Socioeconomic Factors and Environmental Effects as the leading factors in this category.

Walla Walla and Surrounding Area

The Walla Walla area includes no census tracts with an Environmental Health Disparities ranking of 9 or greater.

Figure O.6 – WTN Data – Environmental Exposures in Pacific Power Territory



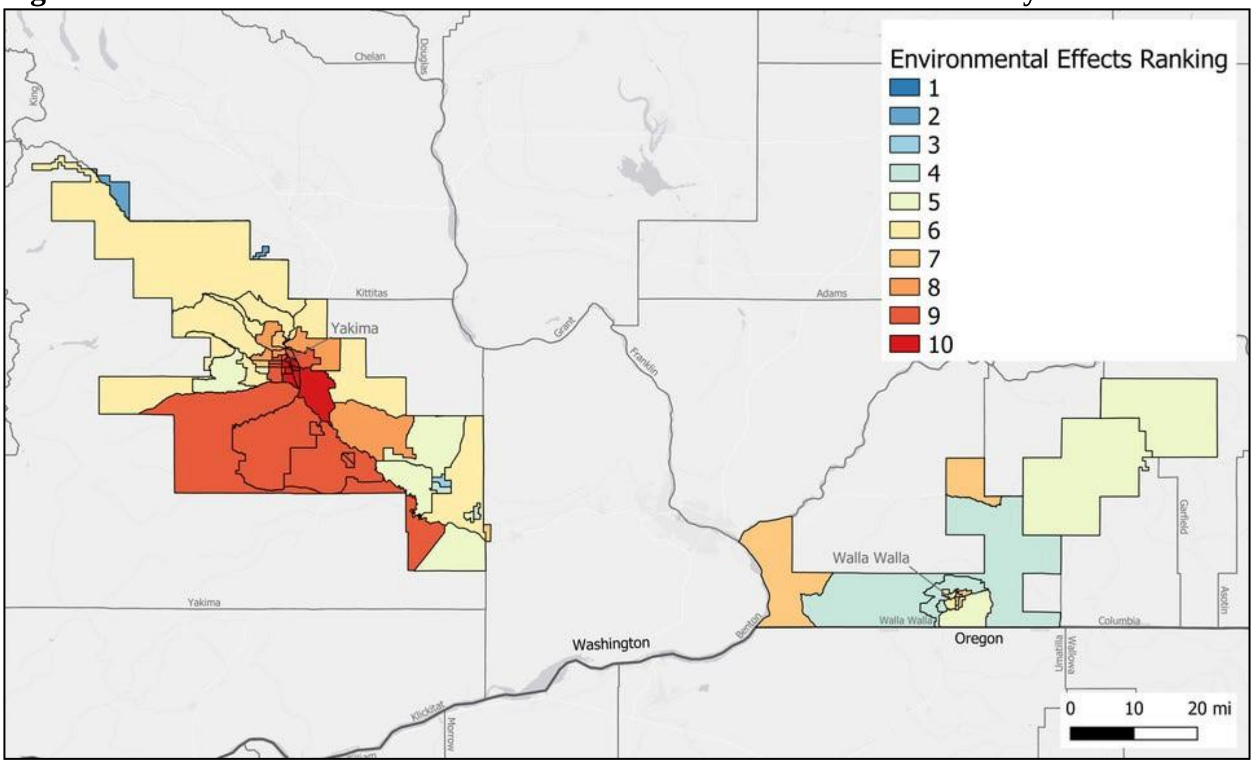
Location	Count of WTN 9/10 Scoring Census Tracts
Environmental Exposures	
Yakima	0
Walla Walla	0

No census tracts within the Yakima area or the Walla Walla area have Environmental Exposures ranking of 9 or greater. Additional information on Environmental Exposures ranking in the Washington service territory are provided below.

Yakima and Surrounding Area
For measures of Environmental Exposures, the Yakima area includes no census tracts with ranking of 9 or greater.

Walla Walla and Surrounding Area
The Walla Walla area does not have a census tract with a ranking above 5 for Environmental Exposures, with many census tracts ranking in the 2-3 range.

Figure O.7 – WTN Data – Environmental Effects in Pacific Power Territory



Location	Count of WTN 9/10 Scoring Census Tracts
Environmental Effects	
Yakima	22
Walla Walla	0

Within the Yakima area, 22 census tracts have Environmental Effects ranking of 9 or greater. The Walla Walla area includes no census tracts with an Environmental Effects ranking of 9 or greater. Additional information on Environmental Effect ranking in the Washington service territory are provided below.

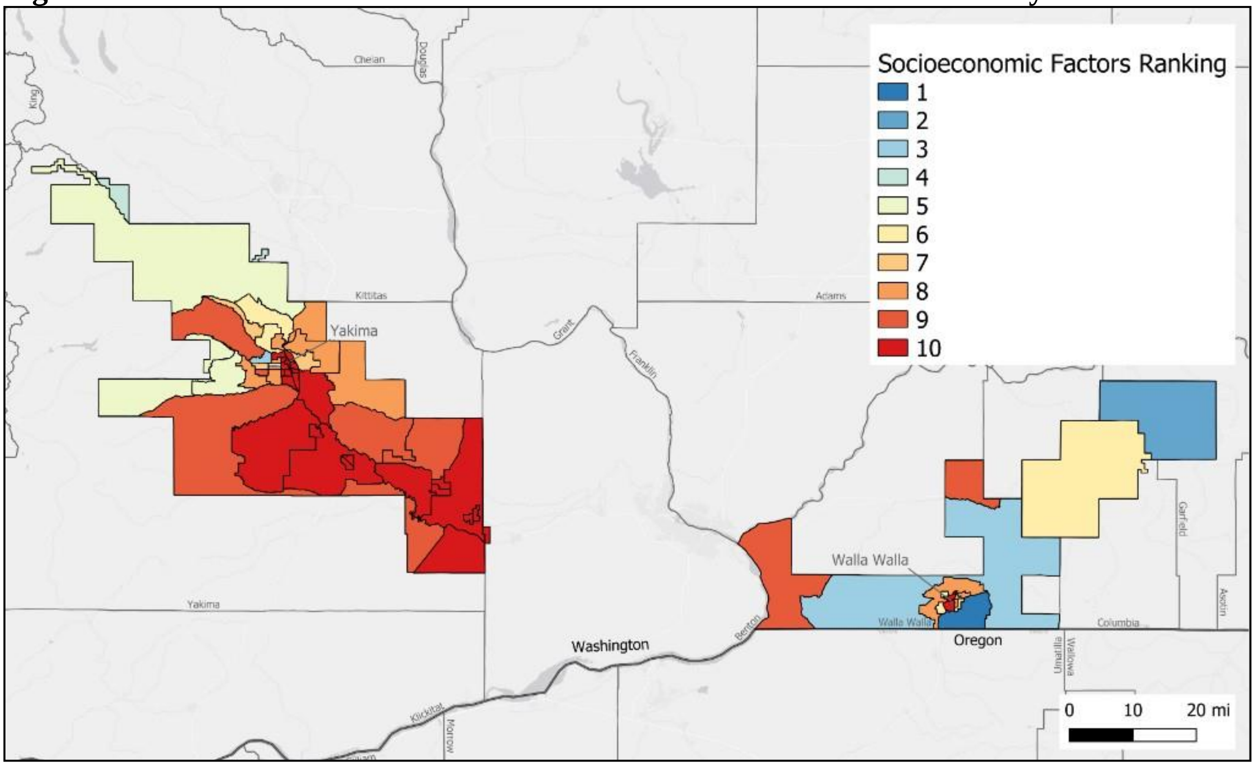
Yakima and Surrounding Area

The Yakima area includes 22 census tracts (46.8%) with Environmental Effects ranking of 9 or greater, with lead risk from housing, proximity to hazardous waste treatment storage and disposal facilities, proximity to superfund sites and proximity to Risk Management Plan facilities as leading factors in this category.

Walla Walla and Surrounding Area

The Walla Walla area includes no census tracts with an Environmental Effects ranking of 9 or greater.

Figure O.8 – WTN Data – Socioeconomic Factors in Pacific Power Territory



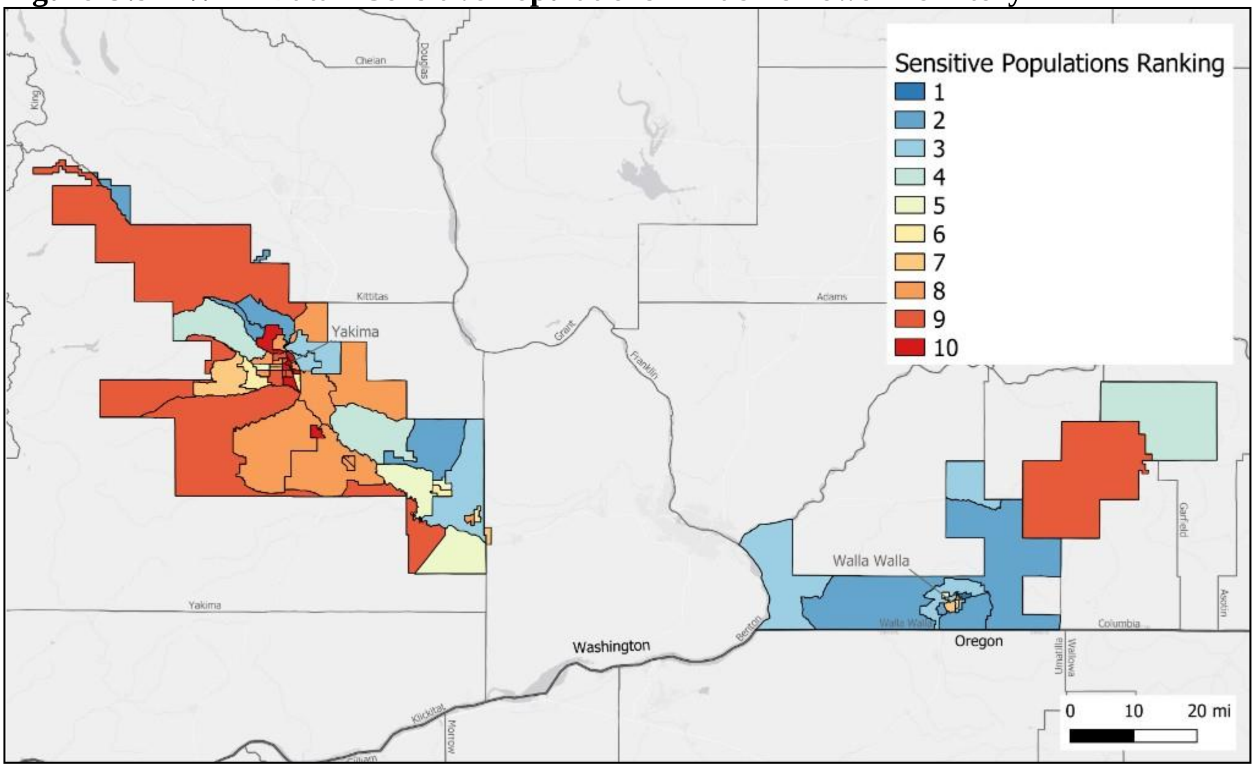
Location	Count of WTN 9/10 Scoring Census Tracts
Socioeconomic Factors	
Yakima	30
Walla Walla	3

Within the Yakima area, 30 census tracts have Socioeconomic Factors ranking of 9 or greater. The Walla Walla area includes 3 census tracts with Socioeconomic Factors ranking of 9 or greater. Additional information on Socioeconomic Factors ranking in the Washington service territory are provided below.

Yakima and Surrounding Area
The Yakima area includes 30 census tracts (63.8%) with Socioeconomic Factors ranking 9 or greater, with major factors being the prevalence of people of color, population living in poverty and high transportation expense.

Walla Walla and Surrounding Area
The Walla Walla area includes 3 census tracts with Socioeconomic Factors ranking of 9 or greater, with major factors being the prevalence of populations with limited English proficiency and populations living in poverty.

Figure O.9 – WTN Data – Sensitive Populations in Pacific Power Territory



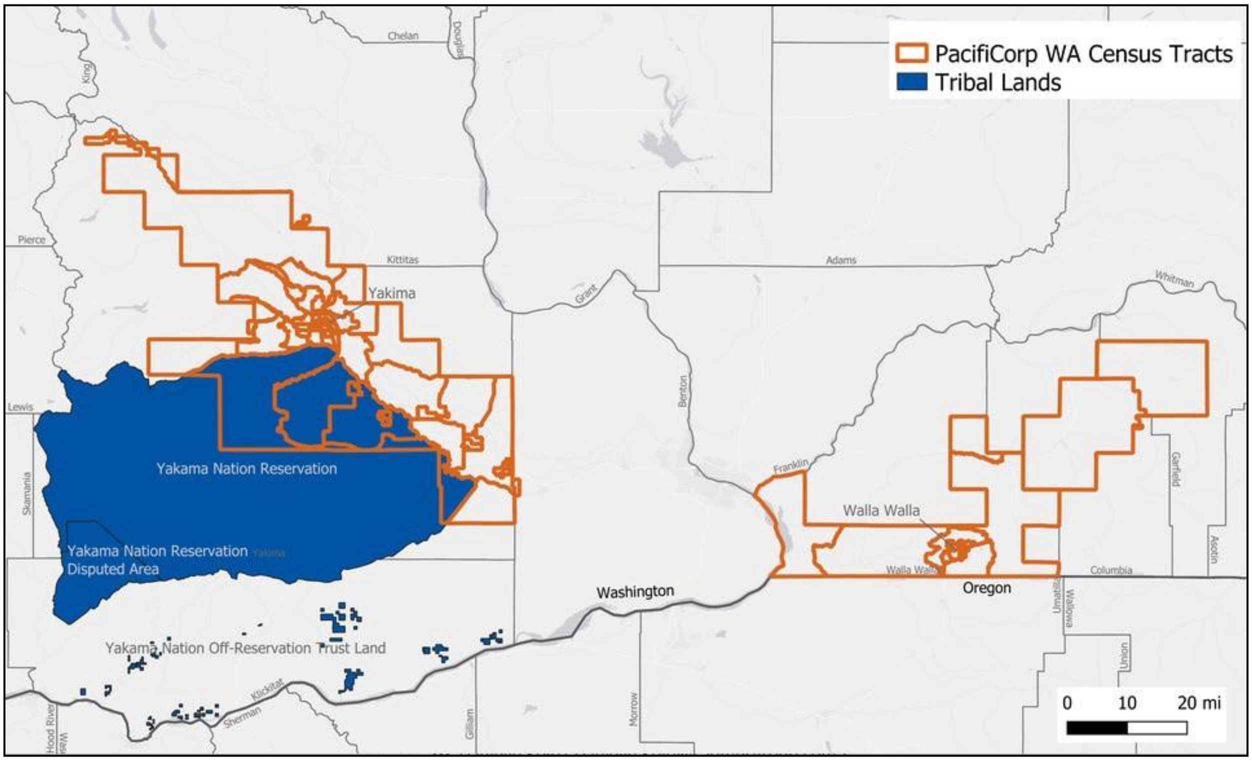
Location	Count of WTN 9/10 Scoring Census Tracts
Sensitive Populations	
Yakima	14
Walla Walla	1

Within the Yakima area, 14 census tracts have Sensitive Populations ranking of 9 or greater. The Walla Walla area has 1 census tract with Sensitive Populations ranking of 9 or greater.
Additional information on Sensitive Populations ranking in the Washington service territory are provided below.

Yakima and Surrounding Area
The Yakima area includes 14 census tracts (29.8%) with Sensitive Populations ranking of 9 or greater, with the major factor being death from cardiovascular disease.

Walla Walla and Surrounding Area
The Walla Walla area includes 1 census tract with Sensitive Populations ranking of 9 or greater, with the major factor being low birth weight.

Figure O.11 – Tribal Land and Pacific Power Territory Map



Location	Number of Census Tracts
Tribal Lands	
Yakima	6
Walla Walla	0

Within the Yakima area, 6 census tracts are located on Tribal Lands. The Walla Walla area has no census tracts located on Tribal Lands. Additional information on Tribal Lands within the Washington service territory are provided below.

Yakima and Surrounding Area
For the Yakima area 6 census tracts are located on the Yakama Nation Reservation.

Walla Walla and Surrounding Area
The Walla Walla area includes no census tracts located on tribal lands.

Identifying Vulnerable Populations

In addition to determining HICs, it is necessary to identify vulnerable populations within the Washington service territory. To that end, PacifiCorp engaged with its external Equity Advisory Group (EAG) to advise on equity issues including vulnerable population designation (WAC 480-100-655). PacifiCorp initially gathered input on vulnerable populations from its EAG members on June 16, 2021, which was further updated on July 21, 2021. The list of those initial vulnerable populations identified by PacifiCorp's EAG is presented in Table O.1 below.

Table O.1 – Initial List of Vulnerable Populations within PacifiCorp Service Territory

Students
Adults 65 years old and above
Young children
People who are hard of hearing
People with a disability
People with medical equipment at home
Diverse supplier business owners
Energy burdened
Asset Limited, Income Constrained, Employed (ALICE)
Low-income migrants
Low income
Immigration status (outside of US citizen)
People who speak limited English
Renters
Multi-generational households
Multi-family households
People experiencing homelessness
People living in rural areas
People living in different land statuses (such as land trust vs. fee patent that have different regulatory requirements)
Agricultural and/or farm workers
Gas-heated homes
Single parents

Table O.2 below provides additional insight on the proportion of PacifiCorp's Washington Service territory customers who belong to a vulnerable population relative to the state of Washington overall. The table shows the average (mean) values of each vulnerable population across all Census tracts in Washington and in PacifiCorp's service territory, respectively, weighted by households or population counts. This average therefore represents the proportion of households or individuals who belong to each vulnerable population across all of Washington and across all of PacifiCorp's Washington service territory.

Table O.2 – Proportion of Vulnerable Populations within Washington and PacifiCorp Service Territory

Vulnerable Population	Washington Statewide Proportions	PacifiCorp Service Territory Proportions
Total population 65 years and over[a]	15.1%	14.6%
Total population under 5 years[a]	6.1%	7.6%
Total civilian noninstitutionalized population with a disability[b]	12.7%	13.7%
Total population foreign born[b]	14.3%	16.9%
Percentage of families and people whose income in the past 12 months is below the poverty level[c]	7.2%	12.1%
Language spoken at home by population 5 years and over: Language other than English[b]	19.1%	32.8%
Number of grandparents living with own grandchildren under 18 years[b]	1.8%	2.8%
Population in households living with other nonrelatives[b]	4.8%	2.9%
Occupied housing units using utility gas for house heating fuel[d]	34.5%	25.1%
Civilian employed population 16 years and over: Agriculture, forestry, fishing and hunting, and mining[c]	2.9%	15.1%
Total households: male or female householder, no spouse/partner present, living alone with own children[b]	15.9%	17.0%
Mean Energy Burden[e]	2.0%	2.8%
School enrollment: Population 3 years and over enrolled in school[b]	23.6%	27.1%
Occupied housing units that are renter-occupied[f]	37.0%	36.1%
Households located in rural areas[g]	5.2%	6.6%
Asset Limited, Income Constrained, Employed[h]	24.7%	30.8%
Minority & Women's Business Enterprises[i] (*total* certified)	2,363	26

[a] US Census Bureau, ACS, 2019, Table DP05
[b] US Census Bureau, ACS, 2019, Table DP02
[c] US Census Bureau, ACS, 2019, Table DP03
[d] US Census Bureau, ACS, 2019, Table S2504
[e] US Department of Energy, Low-Income Energy Affordability Data Tool
[f] US Census Bureau, ACS, 2019, Table DP04
[g] US Department of Agriculture, 2010, Rural-Urban Commuting Areas
[h] United Way Washington: ALICE Project
[i] Washington Office of Minority & Women's Business Enterprises, Directory of Certified Firms. Note: this figure represents the *total* counts of certified MWBEs, as opposed to *percentages*.

In some cases, it was not possible to find an appropriate dataset for vulnerable populations at the needed level of granularity. Vulnerable populations for which PacifiCorp was unable to locate adequate data include people that are hard of hearing, people with medical equipment at home, low-income migrants, people experiencing homelessness, and people living in different land statuses.

Existing Community Programs in Washington

PacifiCorp offers a variety of programs which can be beneficial to customers that are living in a HIC or designated as a vulnerable population (referred to as a Named Communities) such as providing low-cost electricity, which positively impacts housing expenditures and lessens the cost burden for impoverished households. Further, utility programs such as electric vehicle incentive programs impact HIC Environmental Exposures, by lowering NOx from diesel emissions. Below are some additional details regarding a select number of PacifiCorp programs which beneficially impact Washington Named Communities.

- **Low-income Weatherization Program:** Provides energy efficiency services through a partnership between the Company and local non-profit agencies to low-income eligible households residing in single family homes, manufactured homes and multi-unit residential housing. Services are provided at no cost to participants.

- **Project Help – Fuel Fund** provides energy assistance to customers in need with funds donated by customers and employees which PacifiCorp matches 2 to 1 - up to $34k annually in Washington. Donated funds are provided to Project Help in Washington, a non-profit program providing energy assistance with donated funds.

- **Low Income Bill Assistance (LIBA) Program:** Provides a bill discount to income eligible households year-round. A three-tiered bill discount based on the income and monthly billing include a discount on each kWh usage in excess of 600 kWh. The program is administered through partner Low Income Home Energy Assistance Program (LIHEAP) agencies for income certification services.

- **Time-of-Use Pilot Program:** Provides a time of use pilot program which can lower bills for participating customers who can shift usage to off-peak periods of time. This pilot program is limited to the first 500 residential customers that enroll.

- **Energy Efficiency Programs:** Discounts and cash back incentives for qualifying home energy improvements and appliance upgrades.

- **Electric-vehicle Program:** Electric vehicle charging station grants and an electric vehicle ride and drive opportunity.

Analysis of how the 2021 preferred portfolio may help reduce burden and increase benefit

PacifiCorp's 2021 IRP preferred portfolio continues the company's investment in clean energy, affordable service, safety, and reliability. PacifiCorp's initial assessment of how the preferred portfolio actions may impact Washington customers is shown in the table below and will be subsequently refined through the development of Customer Benefit Indicators as part of the development of the 2022 Clean Energy Implementation Plan.

Table O.3 – PacifiCorp Assessment of Preferred Portfolio Impact

Identified Impact or Benefit	How it's addressed in 2021 IRP/CEAP
Energy Benefits	Including the fundamental transition to decarbonize PacifiCorp's system, additional energy benefit is anticipated for Named Communities through participation in company energy electrification and efficiency programs.
Non-energy Benefits	In an effort to prioritize diverse suppliers, PacifiCorp is expanding the non-price scoring criteria associated with utility procurement. Additional information can be found in Volume II, Appendix P (RFP Overview).
Reduction of Burdens	Through the programs identified in the 2021 IRP preferred portfolio – including energy efficiency and demand response – PacifiCorp has the opportunity to deliver programs with an increased equity focus utilizing more effective communication strategies to reach its Named Communities.
Environment/Public Health	Although PacifiCorp does not currently own any generation in its Washington service area, the company's continued investment in clean and non-emitting resources – and the associated retirement of thermal generators – will help reduce environmental exposures across the region. Over time, these investments will reduce environmental exposures and improve air quality.
Reduction in Cost	Washington's allocation of the 2021 preferred portfolio selects resources, programs, locations, and timing meant to lead to the lowest present value revenue requirement compared to overall portfolio risk.
Energy Security/Resiliency	PacifiCorp's preferred portfolio has selected transmission resources that increase east-west transfer capability, harden the system against weather-based threats, and provide the ability to integrate renewable resources.

Public Participation

2021 IRP Stakeholder Meetings

PacifiCorp's long-term planning processes are designed to be transparent, collaborative, and accessible, with a number of meetings held throughout 2020 and 2021.

The development of the 2021 IRP and CEAP began with a public-input meeting in January 2020, which kicked off a total of 18 public-input meetings, with some lasting two days. Due to restrictions and concerns surroundings COVID-19, all meetings were held virtually via phone and the Microsoft Teams platform.

The 2021 public-input process also included state-specific stakeholder meetings held in July and October of 2020. The goal of these sessions were to capture key issues of most concern to each state that PacifiCorp serves, as well as discuss how to address these issues from a system planning perspective. PacifiCorp wanted to ensure stakeholders understood IRP planning principles and its development process. These meetings continued to enhance interaction with stakeholders in the planning cycle and provided a forum to directly address state-specific items of stakeholder interest.

Demand-side Management (DSM) Advisory Group Meetings

PacifiCorp uses its DSM Advisory Group to meet the requirements of WAC 480-109-110. The DSM Advisory Group was initially created under the June 16, 2000, Comprehensive Stipulation in docket UE-991832, which the Commission approved in the August 9, 2000, Third Supplemental Order in that docket, and its IRP public input process created under WAC 480-100-238.

On June 23, 2021, PacifiCorp presented details regarding CETA, the EAG and HICs within the Washington Service Territory to the DSM Advisory Group. Further, on July 21, 2021, PacifiCorp provided details regarding vulnerable populations, draft CBIs, and requested the DSM Advisory Group to complete the Clean Energy Benefit Survey.

CEIP Public Participation Plan

PacifiCorp is working closely with Washington Commission Staff and stakeholders to further expand the participation opportunities within the communities that the company serves in Washington. Detailed public participation methods are outlined in the revised Public Participation Plan for the 2022 CEIP that Pacific Power filed with the Commission on July 3, 2021. As described in the plan, PacifiCorp formed an Equity Advisory Group, and has held four meetings over the May – August 2021 timeframe with another four scheduled through December 2021. PacifiCorp is also seeking input from the public through various other avenues as described in detail in the CEIP Public Participation Plan including upcoming public meetings.

PacifiCorp and Washington Department of Commerce (the Department)

In accordance with RCW 19.405.120, all electric utilities in Washington are required to report data on energy assistance programs to the Department to inform current program adoption and to ensure that programs are meeting the need of Washington customers. As part of this process, PacifiCorp has presented detail on the company’s low-income programs and participated in subsequent workshops to provide further input on low-income programs.

In accordance with CETA requirements, PacifiCorp has also provided program statistics to the Department on the Low-income Weatherization Program, Project Help – Fuel Fund Services and Low-income Bill Assistance (LIBA) Program. PacifiCorp will continue to evaluate options to overlay this work with public data sources to recommend actions to reduce barriers to equitable distribution of benefits.

Part 4: Compliance Pathways

RCW 19.405.040 and 19.405.050 set the 2025, 2030, and 2045 goals for electric utilities in Washington to meet. Specifically, utilities must show that by December 31, 2025 all coal-fired generation has been removed from Washington's allocation of electricity. By January 1, 2030, utilities must be greenhouse gas neutral, and by 2045, Washington's electric utilities must be 100% renewable.

PacifiCorp's 2021 IRP sets the company on the path to meet each of Washington's Clean Energy Transformation Standards. As detailed in Volume I, Chapter 1 (Executive Summary) of PacifiCorp's 2021 IRP, the company is investing in a diverse portfolio that includes investment in renewable and non-emitting resources. The discussion in the Resource Adequacy section of this CEAP describes the ways in which those renewable and non-emitting resources will be allocated to Washington and will help build a clean and reliable portfolio that is fully CETA compliant.

RCW 19.405.090 sets out four alternative compliance pathways that can be used to meet up to 20% of the carbon neutrality standards that begin in 2030 and run through 2044:

> (i) Making an alternative compliance payment under RCW 19.405.090(2);
>
> (ii) Using unbundled renewable energy credits, provided that there is no double counting of any nonpower attributes associated with renewable energy credits within Washington or programs in other jurisdictions, subject to conditions outlined in CETA;
>
> (iii) Investing in energy transformation projects, including additional conservation and efficiency resources beyond what is otherwise required under this section, provided the projects meet the requirements of subsection (2) of this section and are not credited as resources used to meet the standard under (a) of this subsection; or
>
> (iv) Using electricity from an energy recovery facility using municipal solid waste as the principal fuel source, where the facility was constructed prior to 1992, and the facility is operated in compliance with federal laws and regulations and meets state air quality standards.

Based on the 2021 preferred portfolio, PacifiCorp currently forecasts that it will be on track to meet the compliance requirement by using unbundled renewable energy credits in addition to the renewable and non-emitting electric generation to serve Washington customers. At this time, PacifiCorp does not expect to use the alternative compliance payment, energy transformation project, or energy recovery facility pathway to meet the standards under RCW 19.405.090.

APPENDIX P – DRAFT BID EVALUATION AND SELECTION PROCESS FOR 2022 ALL SOURCE REQUEST FOR PROPOSALS

Introduction

The chapter fulfills two state regulatory requirements. First, it fulfills Oregon regulation OAR 860-089-0250(2) requiring a utility to describe its initial scoring and associated modeling in its Integrated Resource Plan or in its Independent Evaluator selection docket. Second, it satisfies Washington regulation WAC 480-107-035 which stipulates that RFP ranking criteria must also be consistent with the avoided cost methodology developed in the IRP the utility uses to support its determination of its resource need.

The 2021 Integrated Resource Plan (IRP) establishes an Action Item to conduct an all-source request for proposals (2022AS RFP) and acquire new resources. The 2021 IRP preferred portfolio includes the following new, incremental resources:

- 1,345 megawatts (MW) of new proxy supply-side generation resources with 600 MW co-located energy storage resources with commercial operation date ("COD") by December 31, 2026.

- 274 megawatts (MW) of new proxy demand-side resources by December 31, 2026[1].

The 2022AS RFP will accept and evaluate all resource types[2] which meet the minimum criteria of this RFP. Prior to the determination of the final shortlist targeted in January 2023, the 2022AS RFP will conduct due diligence and score supply-side and a demand-side resources separately, before dovetailing the processes to evaluate both supply-side and demand-side resource types in parallel using the IRP portfolio optimization models. PacifiCorp will use the results of the RFP to fulfil resource needs for system customers and state compliance obligations.

PacifiCorp is subject to procurement rules in California, Utah, Washington, and Oregon. This chapter begins with a summary of procurement rules in each of the states as they apply to the scoring, evaluation and selection process. The chapter concludes with the proposed bid evaluation and selection process to be used by the 2022 All Source RFP for supply-side resources including the non-price scorecard and equity questionnaire.

[1] Capacity impacts for demand response include both summer and winter impacts within a year.
[2] WAC 480-107-009 107-009 Required all-source RFPs and conditions for targeted RFPs. (1) All-source RFP requirements. All-source RFPs must allow bids from different types of resources that may fill all or part of the characteristics or attributes of the resource need. Such re-source types include, but are not limited to, unbundled renewable energy credits, conservation and efficiency resources, demand response or other distributed energy resources, energy storage, electricity from qualifying facilities, electricity from independent power producers, or other resources identified to contribute to an equitable distribution of energy and nonenergy benefits to vulnerable populations and highly impacted communities.

Review of State Regulatory Requirements

Oregon Regulatory Requirements

In 2016, the Commission initiated the rule making process to develop competitive bidding rules that allow for diverse ownership of renewable energy sources that generate qualifying electricity, consistent with Section 6 of 2016 Senate Bill 1547.[3] After multiple workshops and rounds of comments, the Commission adopted competitive bidding rules in their Order 18-324.[4] Each RFP must demonstrate that it can satisfy these Rules before receiving approval and, after the RFP has taken place, must demonstrate compliance with the Rules in order to receive acknowledgment of a final shortlist.[5]

Oregon's competitive bidding rules describe a two-step process to ensure the Commission and stakeholders are engaged early and often in RFP design. The first step is when a utility describes its initial scoring and associated modeling in its IRP or in its IE selection docket;[6] and the second step is full RFP design and Commission review for approval, conditional approval, or disapproval. This chapter fulfills the first step. The Commission's Rules provide that by including the initial scoring and modeling as part of a utility's IRP filing with the Commission, the Commission acknowledges a resource need as part of the utility's IRP and simultaneously approves the associated RFP scoring methodology and associated modeling process. This RFP scoring and modeling is then incorporated into the complete RFP that is drafted with input from the independent evaluator and stakeholders.

860-089-0100 Applicability of Competitive Bidding Requirements
OAR 860-089-0100 requires PacifiCorp to issue an RFP for all major resource acquisitions meeting specific thresholds including resource sizes greater than 80 MW or contract term length greater than five years. PacifiCorp established an action item out of PacifiCorp's 2021 IRP to conduct an all-source RFP in 2022 to procure 600 MW of new proxy solar resources co-located with 600 MW battery storage capacity, 745 MW of new proxy wind resources, and 274 MW of new proxy demand response resources by the end of 2026. PacifiCorp will also allow bids from nuclear and pumped storage hydro (PSH) resources requiring longer lead time beyond the 2026 deadline to develop and construct and a to be determined amount of new generating resources (including battery storage) in other geographic regions not specified in the 2021 IRP action plan but subject to the results of PacifiCorp Transmission's 2022 cluster study. PacifiCorp's issuance of the 2022AS RFP for its all-source resource additions will satisfy 860-089-0100.

860-089-0350 Benchmark Resource Score
OAR 860-089-0350 applies to the evaluation process and scoring of any utility submitted self-build assets or benchmark bids. In the event benchmark bids are included in the RFP, the following rules apply and have therefore been incorporated into the evaluation and scoring methodology below:

> (1) Prior to the opening of bidding on an approved RFP, the electric company must file with the Commission and submit to the IE, for review and comment, a detailed score for any benchmark resource with supporting cost information, any transmission arrangements,

[3] Codified in Oregon Laws 2016, Chapter 28, Section 6.
[4] Docket No. AR 600, Order 18-324, August 30, 2018.
[5] OAR 860-089-0500 (1).
[6] OAR 860-089-0250(2).

and all other information necessary to score the benchmark resource. The electric company must apply the same assumptions and bid scoring and evaluation criteria to the benchmark bid that are used to score other bids.
(2) If, during the course of the RFP process, the Commission or the IE determines that it is appropriate to update any bids, the electric company must also make the equivalent update to the score of the benchmark resource.
(3) Before the IE provides the electric company an opportunity to score other bids, the electric company must file with the Commission and submit via a method that protects confidentiality the following information:
(a) The final benchmark resource score developed in consultation with the IE, and
(b) Cost information and other related information shared under this rule.

860-089-0400 Bid Scoring and Evaluation by Electric Company
OAR 860-089-0400 provides that the utility must provide all scoring criteria and metrics in its draft and final RFPs filed with the Commission. The initial-shortlist bids must be based on both price and non-price factors, and non-price factors should be converted to price factors where practicable. The non-price score "should be based on resource characteristics identified in the utility's acknowledged IRP Action Plan.... and conformance to the standard form contracts attached to the RFP."[7] Final shortlist bids are then to be based, at least in part, on the bid resources' overall system costs and risks, and the independent evaluator must have full access to the production cost and risk models.

The 2022AS RFP evaluation process will use both price and non-price scoring to determine the initial shortlist. Non-price scoring will involve three weighted factors: (1) bid submittal completeness, (2) contracting progress and viability, and (3) project readiness and deliverability as shown in the non-price scoring matrix at the end of this appendix. Bidders will be required to self-score and provide the results of their scoring to PacifiCorp for its audit and final non-price score determination. As such, bidders will have full transparency to the non-price scoring metrics being used. The non-price scorecard is comprised of three parts. First, to assess bid submittal completeness, bidders will be evaluated upon whether bids provided complete, accurate and consistent information and were in compliance with technical specifications. Second, to assess contracting progression, bidders will be evaluated upon whether the bidder had provided contract issues list, a mark-up of the pro-forma contract, or both and whether certain bid and bidder attributes are consistent with the requirements of the pro forma contracts. Third, to assess project deliverability, bids will be evaluated based on their development maturity, whether they fulfil certain resource attributes consistent with the IRP resource need and are able to achieve a December 31, 2026, commercial operation date, and finally, bidders will be evaluated based upon the extent of previous development-and-construction experience.

This non-price scoring is consistent with PacifiCorp's 2021 IRP Action Plan. PacifiCorp's non-price scoring will also conform to the standard contracts included in the following RFP.

PacifiCorp's price scoring is also consistent with the 2019 IRP analysis because it will use the similar economic models and methodology to evaluate the system impact and costs associated with each bid, as described in the section below, titled "BID EVALUATION AND SELECTION."

[7] OAR 860-089-0400(2)(b).

Upon selection of the initial shortlist, PacifiCorp will engage a third-party engineering firm, to complete an assessment of the resource energy performance reports as submitted by bidders as well as providing additional technical review of the bids for completeness and alignment with technical specifications.

In summary, Oregon has several competitive bidding rules related to an RFP evaluation and scoring, including minimum eligibility requirements for bidders and modeling/scoring uncertainties.[8] This chapter is being provided to address PacifiCorp's conformance with those rules.

Utah Regulatory Requirements

Utah Admin. Code R746-420-1(1)(d) requires a soliciting utility filing for approval of a proposed solicitation and solicitation process in accordance with the Energy Resource Procurement Act (Act) to provide as part of its request for approval filing descriptions of the criteria and the methodology, including any weighting and ranking factors, to be used to evaluate bids.

Utah Admin. Code R746-420-3(2) and (5) requires the 2022AS RFP provide descriptions of the proposed screening and evaluation criteria and the methodology, including any weighting and ranking factors to be used to evaluate bids. Screening, evaluation criteria, ranking factors and evaluation methodologies must be reasonably designed to ensure that the Solicitation Process is fair, reasonable and in the public interest. Reasonable initial screening criteria may include, but are not necessarily limited to, reasonable and nondiscriminatory evaluation of and initial rankings based upon the following factors:[9] (i) Cost to utility ratepayers; (ii) Timing of deliveries; (iii) Point of delivery; (iv) Dispatchability/flexibility; (v) Credit requirements; (vi) Level of change to pro forma contracts included in an approved Solicitation Process; (vii) Transmission, Interconnection and Integration costs and benefits; (viii) Commission-approved consideration of impacts of direct or inferred debt; (ix) Feasibility, including project timing and the process for obtaining necessary rights and permits; (x) Adequacy and flexibility of fuel supplies; (xi) Choice of cooling technology and adequacy of water resources; (xii) Systemwide benefits of transmission infrastructure investments associated with a project; (xiii) Allocation of project development risks, including capital cost overruns, fuel price risk and environmental regulatory risk among project developer, utility and ratepayers; and (xiv) Environmental impacts.

In developing the initial screening and evaluation criteria, the Soliciting Utility shall consider the assumptions included in the Soliciting Utility's most recent Integrated Resource Plan (IRP), any recently filed IRP Update, any Commission order on the IRP or IRP Update and in its Benchmark Option.[10]

Reasonable RFQ screening criteria may include, but are not necessarily limited to, reasonable and nondiscriminatory evaluation of the following factors:[11] (i) Credit requirements and risk; (ii) Non-performance risk; (iii) Technical experience; (iv) Technical and financial feasibility; and (v) Other reasonable screening criteria that are applied in a fair, reasonable and nondiscriminatory manner.

[8] OAR 860-089-0250(3).
[9] R746-420-3(2)(b)
[10] R746-420-3(2)(c)
[11] R746-420-3(3)(c)

For Solicitations which include a Benchmark Option, Utah Admin. Code R746-420-3 (4)(c) requires that the Solicitation shall include at least the following a description and examples of the manner in which resources of differing characteristics or lengths will be evaluated, and Utah Admin. Code R746-420-3 (5)(a) requires that the Solicitation shall include a clear and complete description and explanation of the methodologies to be used in the evaluation and ranking of bids, including a complete description of all evaluation procedures, factors and weights to be considered in the RFQ, initial screening and final evaluation of bids.

Utah Admin. Code R746-420-3 (7)(c) provides that the Solicitation Process must include clear descriptions of qualification requirements, price and non-price factors and weights, and Utah Admin. Code R746-420-3 (7)(d) requires the Solicitation Process must utilize an evaluation methodology for resources of different types and lengths which is fair, reasonable and in the public interest.

Utah Admin. Code R746-420-3 (8) outlines Process Requirements for Benchmark Option. In a Solicitation Process involving the possibility of a Benchmark Option, (h) All relevant costs and characteristics of the Benchmark Option must be audited and validated by the Independent Evaluator prior to receiving any of the bids and are not subject to change during the Solicitation except as provided within the rules; (i) All bids must be considered and evaluated against the Benchmark Option on a fair and comparable basis; and (j) Environmental risks and weight factors must be applied consistently and comparably to all bid responses and the Benchmark Option.

Section 6 (Bid Evaluation and Selection) of the draft 2022AS RFP is included in this chapter and provides a detailed description of the bid scoring, modeling and selection process including assumptions, criteria and methodology that will be used to evaluate, rank, and shortlist bids. As described in the draft 2022AS RFP, the screening and evaluation criteria meet the requirements of the Utah Commission's rule.

Utah Admin. Code R746-420-3(10)(a) requires bids be "blinded;" however, PacifiCorp is recommending that bids not be "blinded." PacifiCorp will request a waiver of this requirement, consistent with similar requests in past RFPs. The Utah Commission has approved such requests previously based, in part, on recommendations by the IE and the Division of Public Utilities, who have questioned the value of blinding the bids. As in past solicitation processes, blinding bids will provide limited value because the detailed information that will be included in each bid will effectively disclose the bidder's identity. Therefore, blinding bids will create an administrative burden on the IE and the Company, with no commensurate value.

Washington Regulatory Requirements

Washington's WAC 480-107 procurement of energy rules (ELECTRIC COMPANIES—PURCHASES OF RESOURCES) requires the following procurement rules with respect to evaluation and scoring processes.

WAC 480-107-009 Required all-source RFPs and conditions for targeted RFPs. (1) All-source RFP requirements. All-source RFPs must allow bids from different types of resources that may fill all or part of the characteristics or attributes of the resource need. Such resource types include, but are not limited to, unbundled renewable energy credits, conservation and efficiency resources, demand response or other distributed energy resources, energy storage, electricity from qualifying facilities, electricity from independent power producers, or other resources identified to contribute to an equitable distribution of energy and nonenergy benefits to vulnerable populations and highly impacted communities.

WAC 480-107-025 Contents of RFP solicitations. (2) The RFP must request information identifying energy and nonenergy benefits or burdens to highly impacted communities and vulnerable populations, short-term and long-term public health impacts, environmental impacts, resiliency and energy security impacts, or other information that may be relevant to identifying the costs and benefits of each bid, such as a bidder's past performance utilizing diverse businesses and a bidder's intent to comply with the labor standards in RCW 82.08.962 and 82.12.962. After the commission has approved the utility's first clean energy implementation plan (CEIP), requested information must contain, at a minimum, information related to indicators approved in the utility's most recent CEIP, including customer benefit indicators, as well as descriptions of all indicators.

(3) The RFP must document that the size and operational attributes of the resource need requested are consistent with the range of estimated new resource needs identified in the utility's IRP.

(4) The RFP must explain the specific ranking procedures and assumptions that the utility will use in accordance with WAC 480-107-035. The RFP must include a sample evaluation rubric that quantifies, where possible, the weight the utility will give each criterion during the bid ranking procedure, and provides a detailed explanation of the aspects of each criterion that would result in the bid receiving higher priority.

(7) The RFP must identify any minimum bidder requirements, including for financial security requirements and the rationale for such requirements, such as proof of a bidder's industry experience and capabilities.

(10) All RFPs must clearly state the scope of the solicitation and the types of bids that the utility will accept consistent with WAC 480-107-024.

WAC 480-107-035 Bid ranking procedure. (1) At a minimum, a utility's RFP ranking criteria must recognize resource cost, market-volatility risks, demand-side resource uncertainties and benefits, resource dispatchability, resource effect on system operation, credit and financial risks to the utility, the risks imposed on ratepayers, public policies regarding resource preference, and Washington state or federal government requirements. The ranking criteria must recognize differences in relative amounts of risk and benefit inherent among different technologies, fuel sources, financing arrangements, and contract provisions, including risks and benefits to vulnerable populations and highly impacted communities. The ranking criteria must also be consistent with the avoided cost methodology developed in the IRP the utility uses to support its determination of its resource need. The utility must consider the value of any additional net benefits that are not directly related to the specific need requested.

(2) In choosing to remove a bid during any stage of its evaluation process, the utility may not base its decision solely on the project's ability to only meet a portion of the resource need.

(3) The utility may not discriminate based on a bidder's ownership structure in the ranking process.

(4) The utility and any independent evaluator selected by the utility will each score and rank the qualifying bids using the RFP's ranking criteria and methodology. If bids include unexpected content, the utility may modify the ranking criteria but must notify all bidders of the change, describe the change, and provide an opportunity for bidders to modify their bids.

(5) Within thirty days after the close of the bidding period, the utility must post on its public website a summary of each bid the utility has received. Where use of confidential data prohibits the utility from identifying specifics of a bid, a generic but complete description is sufficient.

(6) The utility may reject any bids that do not comply with the minimum requirements of the RFP or identify the costs of complying with environmental, public health, or other laws, rules, and regulations in effect at the time of the bid.

(7) Within thirty days after executing an agreement for acquisition of a resource, the utility must file the executed agreement and supporting documents with the commission.

(8) The commission may review any acquisitions resulting from the RFP process in the utility's general rate case or other cost recovery proceeding.

(9) The commission will review, as appropriate, a utility's finding that no proposal adequately serves ratepayers' interests, together with evidence filed in support of any acquisition made outside of the RFP process, in the utility's general rate case or other cost recovery proceeding.

California Regulatory Requirements[12]

California's R.18-07-003 5.10. RPS Plan Section IV.A. Portfolio Supply and Demand states: "The retail seller's RPS Plan must also explain how the quantitative analysis provided in response to Section 5.8 of the ACR supports the assessment. Lastly, it should describe how procurement or sales planned for the period covered by the 2021 RPS Plans is consistent with the evaluation of supply and demand.

R.18-07-003 5.10. RPS Plan Section X: Bid Solicitation Protocol, Including Least-Cost Best-Fit (LCBF) Methodologies - § 399.13(a)(6)(C), D.04-07-029, D.11-04-030, D.12-11-016, D.14-11-042, and D.16-12-044

> R.18-07-003 5.10. X.B. Bid Selection Protocols: The bid solicitation protocols for procuring and selling should include an overview of the solicitation process, a solicitation schedule, and pro forma agreement(s). All retail sellers should include a detailed description of their bid selection process and evaluation methodology, which should be consistent with D.04-07-029, D.11-04-030, D.12-11-016, D.14-11-042, and D.16-12-044. Retail sellers stated bid selection criteria should align with all sections of their RPS Plan, especially regarding stated needs, goals, and preferences retail seller. Retail sellers should describe how their solicitations and procurement decisions will give preference to

[12] Rulemaking 18-07-003, Assigned Commissioner and Assigned Administrative Law Judges' Ruling Identifying Issues and Schedule for Review for 2021 Renewables Portfolio Standard Procurement Plans, dated March 30, 2021, which sets forth the general requirements for 2021 RPS Procurement Plans.

renewable energy resources located in specific communities, such as those identified as disadvantaged communities, pursuant to Pub. Util. Code § 399.13(a)(8).[13]

R.18-07-003 5.10. X.C. Least Cost Best Fit (LCBF) Criteria: The LCBF methodology used must be consistent with relevant Commission decisions.[14] In particular, retail sellers shall include a detailed description of their bid evaluation methodologies and "best fit" attributes considered, pursuant to § 399.13(a)(9),[15] and how bids will be valued and evaluated based on their evaluation methodology. When evaluating bids in their solicitations, retail sellers should consider at a minimum the following attributes: energy and capacity value, congestion cost, locational preference, potential for curtailment, and operational flexibility and how bids will be valued and evaluated based on their evaluation methodology. Any qualitative measures in the LCBF methodology should also be described, both in terms of the criteria and application.[16] If the retail seller's LCBF criteria does not include system reliability considerations then the retail seller's RPS Plan will be rejected.

Bid Evaluation and Selection

Overview of the Evaluation Process

PacifiCorp's bid evaluation and selection process is designed to identify the combination and amount of new resources that will maximize customer benefits through the selection of bids that will satisfy projected capacity and energy needs while maintaining reliability. The same method will be used to evaluate benchmark resources and market bids. Based on proxy resource cost assumptions used in the 2021 IRP, energy and capacity needs were best satisfied by the resource selections summarized in Table P.2. The models that PacifiCorp will use to evaluate and select the best combination and amount of bids are similar to the models that were used to evaluate proxy resources in PacifiCorp's 2021 IRP. PacifiCorp uses the IRP modeling tools to serve as decision support tools that can be used to guide prudent resource acquisition paths that maintain system reliability at a reasonable cost.

The bid evaluation process incorporates PacifiCorp Transmission's interconnection cluster study process steps. At a high level, the 2022AS RFP evaluation process involves three phases:

[13] Pub. Util. Code § 399.13(a)(8)(A) requires that in soliciting and procuring eligible renewable energy resources for California-based projects, each electrical corporation shall give 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 air pollutants, and GHG.

[14] See D.04-07-029, Opinion Adopting Criteria for the Selection Least-Cost and Best-Fit Renewable Resources (July 8, 2004); D.11-04-030, Decision Conditionally Accepting 2011 Renewables Portfolio Standard Procurement Plans and Integrated Resource Plan Supplements (Apr. 14, 2011); D.12-11-016, Decision Conditionally Accepting 2012 Renewables Portfolio Standard Procurement Plans and Integrated Resource Plan Off-Year Supplement (Nov. 8, 2012); D.14-11-042, Decision Conditionally Accepting 2014 Renewables Portfolio Standard Procurement Plans and an Off-Year Supplement to 2013 Integrated Resource Plan (Nov. 20, 2014); D.16-12-044, Decision Accepting Draft 2016 Renewables Portfolio Standard Procurement Plans (Dec. 15, 2016).

[15] Pub. Util. Code § 399.13(a)(9) requires that in soliciting and procuring eligible renewable energy resources, each retail seller consider the best-fit attributes of resource types that ensure a balanced resource mix to maintain the reliability of the electrical grid.

[16] As noted in the November 9, 2018 Assigned Commissioner's Scoping Memo and Ruling issued in R.18-07-003, the Commission is revising and updating the least-cost best-fit methodology for evaluating RPS-eligible procurement. Parties submitted comments on the staff paper on LCBF reform and further Commission action will follow. Thus, parties should limit comments on this Ruling to the particulars of proposed LCBF methodologies in 2021 RPS Procurement Plans in relation to the current rules

1. Initial shortlist
2. Interconnection cluster study, and
3. Final shortlist

The 2022AS RFP evaluation process is shown in Figure P.1 and Figure P.2.

Figure P.1 – Bid Evaluation and Selection Process – Supply-side Resources

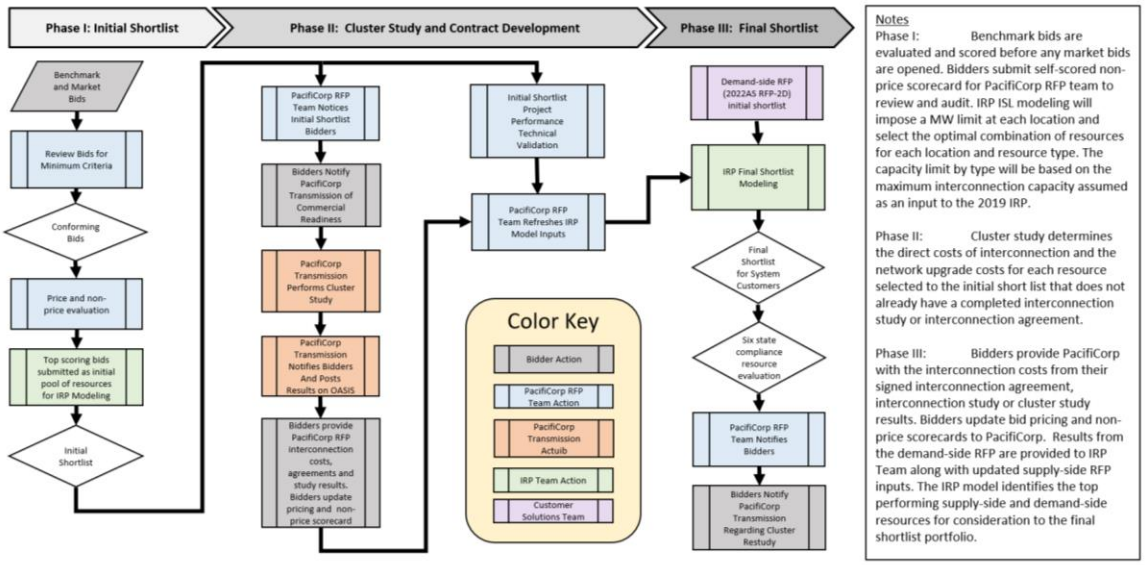
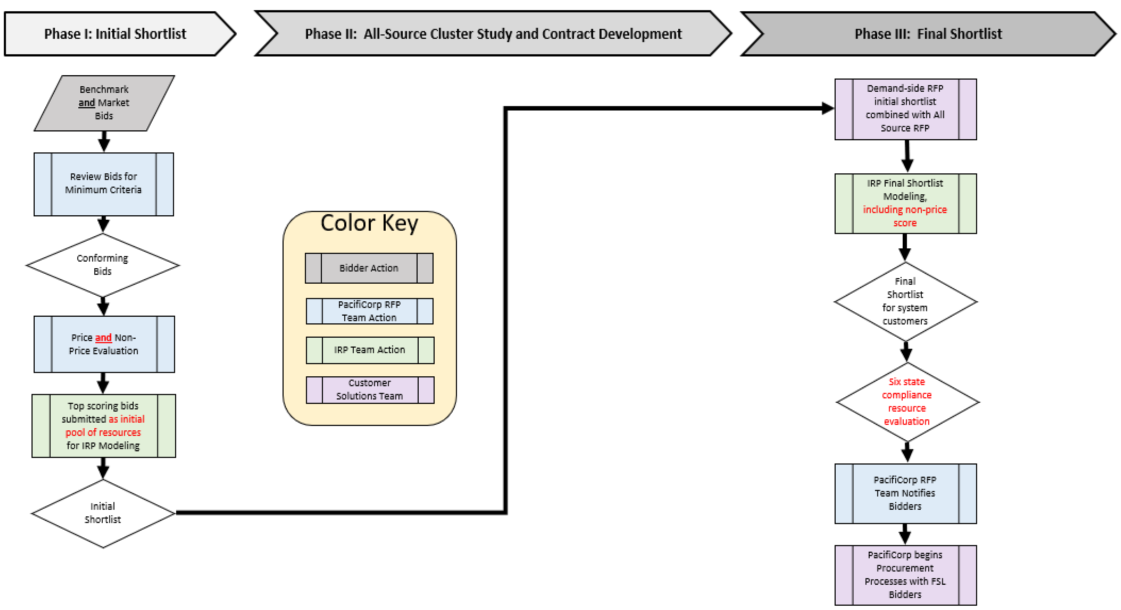


Figure P.2 – Bid Evaluation and Selection Process – Demand-side Resources



Phase I – Initial Shortlist

Phase I of the bid evaluation and selection process includes the due diligence, evaluation and ranking steps leading up to selection of the initial shortlist: i) bid eligibility screening to ensure conformance with the minimum requirements (Section 3.I); ii) price and non-price scoring to rank bids for inclusion in IRP portfolio optimization models; and iii) IRP modeling used to select the lowest cost bids for inclusion to the initial shortlist. During this phase of the bid evaluation process, PacifiCorp will not ask for, or accept, updated pricing or updates to any other bid components. PacifiCorp will rely on the pricing and other inputs as submitted into the 2022AS RFP for each benchmark and market resource to evaluate and rank bids. However, PacifiCorp will contact bidders to confirm and clarify information presented in each proposal. The pricing model will be made available to the IE, but not to bidders or stakeholders.

1. Conformance to Minimum Requirements

Benchmark and market bids will initially be screened after receipt against minimum requirements to determine RFP conformance and eligibility. After IE review and consultation, non-conforming bids will be notified to correct their bid within two (2) business days or be removed from the RFP. Consistent with OR 860-089-0400 (2), non-price score criteria that seek to identify minimum thresholds for a successful bid have been converted into minimum bidder requirements.

2. Price and Non-Price Scoring and Ranking

After PacifiCorp has screened for eligibility, conforming bids will be evaluated and given price and non-price scores. Each benchmark resource and market bid will be ranked based on the sum of their price and non-price bid score. A maximum of 75 points are allocated to price scoring and a maximum of 25 points for non-price scoring for a total maximum score of 100 points. Bids are then ranked, and the top performing bids are chosen to be the initial pool of resources to be considered as alternatives by the IRP model in selecting the initial shortlist.

Table P.1 – Scoring to Determine Initial Pool of Resources for IRP Modeling

	Maximum Score
1. Price	75 points
2. Non-price score	25 points

Price scores are determined using PacifiCorp's proprietary pricing models. Non-price scores are determined using a non-proprietary tool. Developers will be asked to grade themselves as part of their bid package, which PacifiCorp will audit before determining a final non-price score for each bid. More detail on the price and non-price score methodology is provided below.

The sum of the price and non-price scores will be ranked and compared against bids in similar geographic regions of PacifiCorp's territory. The 2021 IRP preferred portfolio selected cost-effective resources in three areas of PacifiCorp's territory where transmission upgrades prior to the 2026 COD deadline enabled additional resources to interconnect to PacifiCorp's transmission system and be transmitted to load (Table P.2). PacifiCorp may also consider a to-be-determined amount of new generating resources (including battery storage) in other geographic regions not specified in the 2021 IRP action plan but subject to the results of PacifiCorp Transmission's 2022 cluster study.

Table P.2 – PacifiCorp preferred portfolio transmission selections

Year	MW	Type	From	To	Description
2026	615	Wind	Within Willamette Valley OR Transmission Area		Enables 615 MW of interconnection: Albany, OR area reinforcement
2026	130	Wind	Portland North Coast	Willamette Valley	Enables 2080 MW of interconnection with 1950 MW TTC. Portland Coast area reinforcement, Willamette Valley and Southern Oregon
2026	600	Solar plus storage	Borah-Populous	Hemingway	Enables 600 MW interconnection with 600 MW TTC: B2H Boardman-Hemingway

1 - TTC = total transfer capability. The scope and cost of transmission upgrades are planning estimates. Actual scope and costs will vary depending upon the interconnection queue, the transmission service queue, the specific location of any given generating resource and the type of equipment proposed for any given generating resource.

For the purposes of selecting a pool of resources to be considered by the IRP model for the initial shortlist, PacifiCorp will rank the sum of price and non-price score for each resource type in each geographic region. For the locations listed in Table P.2, PacifiCorp will choose up to 150% of the MW capacity selected in the preferred portfolio for the IRP model to choose from in the initial shortlist process. For all other regions not represented in the preferred portfolio, PacifiCorp will choose up to a to-be-determined amount of installed MW bids in other geographic areas of PacifiCorp system to be included in the pool of resources from which the IRP model may select the initial shortlist.

If PacifiCorp determines that there is a distinct change in bid scores at a level of capacity that falls short or exceeds this capacity limit, the company will coordinate with the IE to establish a limit by resource type that could either fall below or exceed the maximum total capacity for a given location.

- **Price Score (up to 75 points).** PacifiCorp's proprietary price scoring model will calculate the delivered revenue requirement cost of each bid, inclusive of any applicable carrying cost and net of tax credit benefits, as applicable. In developing the revenue requirement cost for each bid, PacifiCorp requires certain cost data as inputs to the price score model. Table P.3 contains a summary of the cost and benefit component which are required and included in PacifiCorp's valuation analysis broken by bid structure.

Table P.3 – Summary of Cost/Benefit Components by Bid Structure

Component	PPA Option	BTA Option	Toll Option
Initial Capital Revenue Requirements (net of ITC, if solar)	-	(X)	-
Ongoing Capital Revenue Requirements	-	(X)	-
PTC Benefit (if wind)	-	Z	-
Terminal Value	-	Z	-
O&M, Lease/Royalty, Insurance	-	(X)	-
Property Taxes	-	(X)	-
State Generation Tax (if Wyoming or Montana)	-	(X)	-
Network Upgrade Revenue Requirements	(X)	(X)	(X)
Transmission Wheeling and Losses (if off-system)	(X)	(X)	(X)
PPA Price	(X)	-	-
Storage Costs	(X)	(X)	(X)
Energy Arbitrage and Operating Reserve Storage Value[17]	Z	Z	Z

[17] Energy Arbitrage and Operating Reserve Storage Value are only calculated for PPA and BTA bids include a dispatchable (e.g. battery storage) component.

Generation Energy Value (net of balancing area reserve obligation)	Z	Z	Z
Integration Cost	(X)	(X)	(X)

Z	Benefit
(X)	Cost

Any internal assumptions for key financial inputs (*i.e.*, inflation, discount rates, marginal tax rates, asset lives, AFUDC rates, *etc.*) and PacifiCorp carrying costs (*i.e.*, integration costs, owner's costs, *etc.*) will be applied consistently to all bids, as applicable. PacifiCorp anticipates that it will receive some bids which have an executed LGIA and other bids which will not yet have been studied by PacifiCorp Transmission. To ensure there is a fair comparison among bids, bidders shall not include the cost for any direct assigned interconnection costs in their bids, and PacifiCorp will not include the cost of transmission network upgrades associated with the proposed project in the initial shortlist price evaluation. As described in greater detail below, at the conclusion of the cluster study phase, as part of updating bid pricing, bidders will add interconnection costs to their refreshed prices for final shortlist evaluation.[18]

PacifiCorp's proprietary price scoring model scores each bid based on its net benefit to the system. The model uses system-value curves, which are developed and locked down with the IE in advance of receiving bids. The system-value curves are developed by the IRP Team using Plexos, which calculates the hourly marginal system energy value of a flat energy profile and the hourly marginal operating reserve value of a flat operating reserve profile, for each location in PacifiCorp's territory. The proprietary model also incorporates regional reserve values (PACE and PACW) provided by the IRP team.

The proprietary pricing model nets bid costs against the applicable system-value curve. Then, it calculates an inflation-adjusted real-levelized net cost or net benefit expressed in "$/MWh" for each bid. Finally, each bid's nominal net benefit is force ranked to determine the bid's price score. For each technology (resource type) in each transmission cluster bubble location, a maximum score of 75 points is assigned to the bid with the highest calculated net benefit and a minimum of zero (0) points to the evaluated bid with the lowest calculated net benefit. The remaining bids of that same technology[19] and location are scored on a 0-to-75-point scale according to their relative relationship (respective net benefits) to those of the highest and lowest performing bids.

- <u>Non-Price Score (Up To 25 points)</u>. The non-price evaluation rubric is included at the end of this appendix and will be included in an RFP issued to market.[20] For each non-price factor, proposals will be assigned a one or a zero. PacifiCorp's non-price scoring model evaluates whether bids are thorough and comprehensive, whether the proposed resource is viable, and whether the bidder is likely to achieve commercial operation by December 31, 2026. The non-price rubric is designed to be objective, intuitive, and self-scoring. As a bid requirement, bidders are required to score themselves based on the completeness of RFP

[18] We will not accept price increases (exclusive of direct assigned and network upgrade costs) greater than ten percent above original bid.
[19] Technology means…. Generating facilities inclusive of batteries are considered different technology from facilities that only have the generating facility and no battery storage option.
[20] OAR 860-089-400-2(b).

bid requirements, the ability to contract with the project, and the maturity of the project and ability to deliver the project by the commercial operation deadline.

Table P.4 – Non-Price Factor Weighting

Non-Price Factor	Maximum Non-Price Factor Points
1. Bid Submittal Completeness	5 points
2. Contracting Progress and Viability	5 points
3. Project Readiness and Deliverability	15 points

The first section of non-price scoring model is similar to a checklist and grades bids based on completion of bid requirements such as providing complete, thorough and consistent responses. The second section grades bidders based on the ability to contract the resource bid. The third section of the non-price scoring model assesses each bid's development status and viability. Points are earned based on degree of site control, permit attained, completed equipment sourcing strategy and other operational characteristics such as dispatchability and having a reasonable construction schedule.

In compliance with OR 860-089-0400 (2), non-price factors have been converted to price factors where practicable. Non-price scores primarily relate to resource characteristics identified in the electric company's most recent acknowledged IRP Action Plan and reflect standard form contracts. Non-price scoring criteria is objective and reasonably subject to self-scoring analysis by bidders. Finally, non-price score criteria that seek to identify minimum thresholds for a successful bid have been converted into minimum bidder requirements.

All resources are required to complete the equity questionnaire included with the RFP. When considering California-located resources and resources allocated to Washington customers, PacifiCorp has a preference for projects that provide environmental and economic benefits to disadvantaged communities. For resources located in California, PacifiCorp has a supplier diversity target of 23% women-owned, minority-owned, disabled veteran-owned and LGBT-owned business enterprises and we encourage the bidder to register with California's supplier clearing house. When considering resources to be allocated to Washington customers, equity questionnaire responses will be used in Phase III of the evaluation process to measure Washington community benefit indicators as part of Washington's Clean Energy Transformation Act ("CETA"). Oregon-located resources should be able to demonstrate their ability to meet the requirements of HB2021, including but not limited to apprenticeship and workforce requirements.

- **Final Ranking (up to 100 points) to determine the Initial Resource Pool to be evaluated using the IRP models.** PacifiCorp will use the combined price and non-price results to rank each benchmark resource and market bid. Based on these rankings, PacifiCorp will identify an initial pool of resources by location and resource type based on the total bid score (maximum at 100 points, with a maximum of 75 points for price and a maximum of 25 points for non-price factors). This initial pool of resources will be made available as resource alternatives for IRP modeling.[21]

[21] Note, in instances where bidders offer a bid alternative for the same resource type in the same location, only the highest scoring bid alternative for that location and resource type will be included in the initial pool of resources.

When considering tiebreakers for inclusion in the initial pool of resources to be evaluated by the IRP model and considered for the initial shortlist, PacifiCorp will give 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 air pollutants, and greenhouse gases when ranking projects.[22]

3. IRP Modeling and Selection of the Initial Shortlist

Following the Price and Non-Price Scoring, PacifiCorp will submit the initial pool of resources to the IRP team to select resources for the initial shortlist. The IRP team will evaluate the initial pool of resources using Plexos, the same production cost models used in the 2021 IRP. PacifiCorp will first process bid costs for IRP modeling; consistent with the treatment of capital revenue requirement in PacifiCorp's IRP modeling, PacifiCorp will convert any calculated revenue requirement associated with capital costs, as applicable (i.e., return on investment, return of investment, and taxes, net of tax credits, as applicable) to first-year, real-levelized costs. All other benchmark resource and market bid costs will be summarized in nominal dollars and formatted for input into to the IRP models, consistent with the treatment of non-capital revenue requirement in PacifiCorp's IRP modeling. Projected renewable resource performance data (expected hourly capacity factor information) will also be processed for input into the IRP models. The IRP production cost models will then select the optimized portfolio of resources.

The IRP modeling tools will select the least cost resource types by location based on bid cost and performance data. PacifiCorp's initial shortlist may also include high-scoring bids in excess of the identified capacity limits if those projects have completed interconnection studies and will not be participating in PacifiCorp Transmission's interconnection cluster study process commencing in May 2022.

PacifiCorp will not make any of the IRP evaluation models available to the IE, bidders, or stakeholders. However, PacifiCorp will summarize for the IE how the IRP evaluation models function, and the IE will be provided with the inputs and outputs of all IRP models used during the evaluation process.

4. Initial Shortlist Notification by PacifiCorp

PacifiCorp will notify bidders that were selected to the initial shortlist in Phase I.

5. Bidder Notification to PacifiCorp Transmission

Immediately upon their selection to the initial shortlist, bidders will be required to notify PacifiCorp Transmission to demonstrate they have met the OATT's "commercial readiness" criteria. Bidders shall be responsible for also having satisfied any other PacifiCorp Transmission defined requirements established in the OATT. There should be no discrepancy between the facility characteristics bid into the RFP and what bidders have communicated to PacifiCorp Transmission as part of the cluster study application process. Bidders will be

[22] Pub. Util. Code § 399.13(a)(5)(7)(A) requires the following: "In soliciting and procuring renewable energy resources for California based projects, each electrical corporation shall give preference to renewable 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 air pollutants and greenhouse gas emissions."

responsible to ensure that their bid(s) submitted to PacifiCorp in response to the 2022AS RFP are in compliance with and represent their interconnection service requests and/or existing contracts between Bidder and PacifiCorp Transmission.

Bidders assume the risk, and PacifiCorp will not be held liable, in the event that a bid selected to the initial shortlist in the 2022AS RFP is deemed ineligible for PacifiCorp's cluster study due to deviations between the submitted project bid and the LGIA, study documentation, or application associated with such project as submitted to PacifiCorp Transmission, or due to a Bidder's failure to satisfy any other requirement of PacifiCorp's OATT. Bidders will be required to meet all requirements of PacifiCorp Transmission's cluster study process including deposits, payments, milestones and any penalties associated with withdrawals from the cluster process and could be subject to disqualification from the 2022AS RFP for any violation during the cluster study process.

Phase II – Interconnection Cluster Study

Phase II is composed of the following tasks: cluster study report issued by PacifiCorp Transmission, resource capacity factor and storage performance verification performed by third-party consultants for PacifiCorp, and finally, bid updates by the initial shortlist bidders.

1. Interconnection Cluster Study Report

PacifiCorp will screen each benchmark and market bid and confirm that it is consistent with available interconnection documentation.[23] The cluster study report is expected to take approximately six months and will be performed by PacifiCorp Transmission in accordance with the OATT.

2. Resource Capacity Factor Verification

PacifiCorp will engage a third-party subject matter expert to verify the capacity factor of the proposed wind and solar resources selected to the initial shortlist consistent with Oregon rule 860-089-0400 5(a). This task will be done in parallel with the cluster study.

3. Bid Update

At the conclusion of the interconnection cluster study process, results of the cluster study will be posted to Open Access Same-time Information System (OASIS) and participating parties including the initial shortlist bidders will be notified of their results. Bidders will be required to provide PacifiCorp with their cluster study results or any updates to their existing interconnection studies and interconnection agreements and a summary of the direct assigned interconnection costs and network upgrade portions from their respective studies and agreements. Bidders will also be required to provide updated non-price scorecards and equity questionnaires. Finally, bidders will be required to provide updated bid prices which shall now include the direct assigned portion of their interconnection costs in their prices for PacifiCorp's analysis and evaluation. Best and final pricing must be provided for the same site and same interconnection proposed and studied as their original bid, with same or similar project equipment so that there is no material modification required with PacifiCorp Transmission,

[23] PacifiCorp Transmission customers retain the right to downsize the Project up to 60 percent prior to the return of the executed Cluster Study Agreement, per PacifiCorp OATT Volume 11 (2020.07.10), Section 39.4.1.

and on the same COD timeline as originally proposed. With the exception of price increases attributed to the direct interconnection costs assigned by PacifiCorp Transmission, Bidders may only increase bid price by 110% of what was originally offered or be subject to disqualification.

Phase III – Final Shortlist

Phase III is the selection of the final shortlist. In Phase III, PacifiCorp will review the cluster study results and any amended LGIAs and re-run Phase I price models to confirm bid conformance with minimum criterial. PacifiCorp will then process updated pricing, verified capacity factors and storage inputs, for inclusion in the IRP production cost models. Plexos (the same model used by PacifiCorp to develop resource portfolios in the 2021 IRP) will be rerun to develop a resource portfolio. As was done in the 2021 IRP and in Phase I, PacifiCorp will perform a reliability assessment to ensure that the selected portfolio of resources can meet all hourly load and operating reserve requirements with sufficient cushion to account for other system uncertainties such as non-normal weather events. Should incremental flexible resource capacity be required to maintain system reliability, additional resources will be selected from the initial shortlist of bids that are capable of providing incremental flex capacity or remove resources to hit the targeted reliability requirements. PacifiCorp will not update the non-price portion of the bid evaluation from Phase I. However, cost and risk analysis, along with any other factors not expressly included in the formal evaluation process, but required by applicable law or commission order, will be used by PacifiCorp, in consultation with the IE, to establish the final shortlist.

1. Cluster Study Results

PacifiCorp will analyze the results of the cluster study as well as any updated and amended LGIAs to determine any limits to available transmission capacity which might prevent bidders from meeting the December 31, 2026 COD deadline. PacifiCorp will then utilize the same proprietary models used in the Phase I initial ranking to ensure bidders have updated their pricing according to the requirements of the 2022AS RFP and not increased their pricing more than 110% apart from increases resulting from the inclusion of interconnection costs. In this way, PacifiCorp will reconfirm bidder eligibility with minimum criteria of the RFP.

2. Processing of Bid Updates

Similar to the Phase I pricing evaluation, PacifiCorp uses its proprietary models to process bid updates. The models are refreshed with updated bid prices, including interconnection costs from cluster study results and any LGIA updates, verified capacity factors and storage inputs. Consistent with the treatment of capital revenue requirement in PacifiCorp's IRP modeling, PacifiCorp converts any calculated revenue requirement associated with capital costs (i.e., return on investment, return of investment, and taxes, net of tax credits, as applicable) to first-year-real-levelized costs. Consistent with the treatment of non-capital revenue requirement in PacifiCorp's IRP modeling, all other bid costs are summarized in nominal dollars and formatted for input into to the IRP models. Projected renewable resource performance data (expected hourly capacity factor information) is also processed for input into the IRP models.

3. Combining of Supply-Side and Demand-Side RFPs Prior to Final Shortlist

At the same time initial shortlist bidders are updating their prices, and prior to the final evaluation and selection of the final shortlist, the shortlist bidders from the demand-side RFP will be available for incorporation and inclusion to the IRP models.

4. Bid Resource Portfolio Development

After initial shortlist bidders update their pricing to include interconnection costs and it is processed for inclusion in the IRP model, and after the demand-side RFP resources have been incorporated into the IRP model, the IRP team uses the Plexos model to optimize the portfolio of resources and select the final shortlist. PacifiCorp uses Plexos to develop and evaluate the cost of multiple resource portfolios.

PacifiCorp evaluates portfolios under a range of different environmental policy and market price scenarios (policy-price scenarios).[24] In this way, PacifiCorp uses Plexos to optimize its selection of bid resources to identify the lowest cost, reliable portfolio under multiple scenarios prior to undergoing additional stochastic risk analysis and further consideration as part of the final shortlist process.

5. Stochastic Risk Analysis

PacifiCorp next uses Plexos to evaluate each portfolio and its ability to perform under dynamic weather and market conditions. Plexos measures the stochastic risk of each portfolio through its production cost estimates. By holding a resource portfolio fixed and using Monte Carlo simulations of stochastic variables, including load, wholesale electricity and natural gas prices, hydro generation, and thermal unit outages, Plexos can measure the expected cost of each portfolio in an uncertain future.

6. Identifying Top-Performing 2022AS RFP Renewable Resource Portfolios

PacifiCorp then summarizes and analyzes the portfolios to identify the specific bid resources that are most consistently selected among the policy-price scenarios. Based on these data, as well as certain qualitative criteria, and in consultation with the IE, PacifiCorp may select one or more 2022AS RFP resource portfolios for further scenario risk analysis.

7. Scenario Risk Analysis

Plexos will be used to calculate the stochastic mean PVRR and the risk-adjusted PVRR for various policy-price scenarios.[25] This step of the evaluation process will help identify whether top-performing portfolios exhibit especially poor performance under the range of scenarios.

PacifiCorp takes the information from the prior steps and develops new system resource portfolios based on the top-performing resource portfolios in the prior steps. For each, it then

[24] Policy-price scenarios will be conceptually consistent with those used in the 2021 IRP (i.e., alternative environmental policy assumptions among low, medium, and high price scenarios), but updated to reflect PacifiCorp's assessment of the most current information. Policy-price scenario assumptions will be established and reviewed with the IE before updated bids with updated pricing are received and opened.

[25] The stochastic mean metric is the average of system net variable operating costs among 50 iterations, combined with the real-levelized capital costs and fixed costs taken from Plexos. The risk-adjusted metric adds 5% of system variable costs from the 95th percentile to the stochastic mean. The risk-adjusted metric incorporates the expected value of low-probability, high-cost outcomes.

calculates a stochastic mean PVRR and a risk-adjusted PVRR for each policy price-scenario before recommending a lowest cost, lowest risk portfolio from which to draw the final shortlist.

8. Other Factors: Applicable Law and Statutory Requirements

Before establishing a final shortlist, PacifiCorp may take into consideration, in consultation with the IE, other factors that are not expressly or adequately factored into the evaluation process outlined above, particularly any factor required by applicable law or Commission order to be considered.[26]

9. Final Shortlist Selection

PacifiCorp will summarize and evaluate the results of its scenario risk analysis, considering PVRR results, to identify the specific least-cost, least-risk bids. Based on these data and certain other factors as described above, and in consultation with the IE, PacifiCorp may establish a final shortlist.

Selection of the final shortlist will not be conditioned on the results of any future restudy arising out of the applicable PacifiCorp Transmission cluster study process.

After the final shortlist is established and approved, PacifiCorp will re-engage in negotiations with the selected bidders to finalize their contract and prepare the contract for execution. Selection of a bid to the final shortlist does not constitute a winning bid. Only execution of a definitive agreement between PacifiCorp and the bidder, on terms acceptable to PacifiCorp, in its sole and absolute discretion, will constitute a winning bid proposal.

10. Additional State Requirements

Following the final shortlist selection, PacifiCorp may consider resources additions and changes required for state compliance purposes. For example, to address Washington's CETA, in consultation with the IE, PacifiCorp will evaluate the final shortlist bids designated in part to serve Washington customers. In accordance with WAC 480-107-035, PacifiCorp will review the Equity Questionnaire for each resource and evaluate the associated risks and benefits to vulnerable populations and highly impacted communities associated with those bids. PacifiCorp, in consultation with the IE, may add or replace resources allocated to Washington customers in order to meet CETA goals with the understanding that the incremental cost associated with those resources would later be assigned to Washington customers.

Minimum Eligibility Requirements for Bidders (RFP Section 3.I)

Bidders may be disqualified for failure to comply with the RFP if any of the requirements outlined in this RFP are not met to the satisfaction of PacifiCorp, as determined in its sole discretion. If proposals do not comply with these requirements, PacifiCorp has the option to deem the proposal non-conforming and eliminate it from further evaluation. Reasons for rejection of a bidder or its proposal include, but are not limited to:

1. Receipt of any proposal after the bid submittal deadline.
2. Failure to submit the required Bid Fee when due.

[26] Footnote to UT, OR, WA, CA requirements.

3. Failure to meet the requirements described in this RFP and provide all information requested in Appendix C-2 - Bid Summary and Pricing Input Sheet of this RFP.
4. Failure to adequately demonstrate the viability of a COD on or before December 31, 2026 with the exception of long-lead resources as described in Section 1.C.
5. Failure to permit disclosure of information contained in the proposal to PacifiCorp's agents, contractors, regulators, or non-bidding parties to regulatory proceedings consistent with terms of executed confidentiality agreement.
6. Any attempt to influence PacifiCorp in the evaluation of the proposals outside the solicitation process.
7. Failure to provide a firm offer through the bid validity date outlined in Section 3.E. of this RFP.
8. Between date of initial cover letter accompanying bid and the bid validity date, failure to disclose to PacifiCorp at any time bidder has committed their project to another entity.
9. Failure to disclose the real parties of interest in any submitted proposal.
10. Failure to clearly specify all pricing terms for each base proposal and alternative(s).
11. Failure to offer unit contingent (as generated) or system firm capacity and energy to Company's network transmission system in either its PACE and PACW balancing areas.
12. For any bid that is proposing to interconnect to a third-party transmission system and secure transmission service to deliver the output of the resource to PacifiCorp at PACE or PACW, failure to provide a system impact study by the third-party transmission provider as well as satisfactory evidence that firm transmission rights are already secured in bidder or project owner's name or readily obtainable by bidder. Evidence of transmission rights must demonstrate that bidder can deliver the full output of the resource to PacifiCorp on or before December 31, 2026 and must detail all actual or estimated transmission costs.
13. Failure to materially comply with technical specification requirements in Appendix A -Technical Specifications for BTA proposals involving potential PacifiCorp ownership or operational control.
14. Failure to demonstrate a process to adequately acquire or purchase major equipment (i.e., wind turbines, solar photovoltaic panels, inverters, tracking system, generator step-up transformers, batteries) and other critical long lead time equipment.
15. Failure to demonstrate that it can meet the credit security requirements for the resource proposed.
16. Failure to submit information required by PacifiCorp to evaluate the price and non-price factors described herein.
17. Failure or inability to abide by the applicable safety standards.
18. Failure to submit an acceptable contract structure.
19. A determination by PacifiCorp that collusive bidding or any other anticompetitive behavior has occurred.
20. Bidder or proposed project being bid is involved in bankruptcy proceedings.
21. Failure of the bidder's authorized officer to sign the proposal cover letter as required in this document and without edits.
22. Misrepresentation or failure to abide by Federal Trade Commission Green guidelines for renewable projects, if applicable.
23. Any change in law or regulatory requirements that make the bidder's proposal non-conforming.

24. Any matter impairing the bidder, the specified resource, or the generation of power or, if applicable, environmental attributes from the specified resource.
25. Failure to provide the minimum resource performance estimate information as described in Section 5.B. of the RFP.
26. Failure to provide a performance model output including hourly output values as identified in Appendix C-3 - Energy Performance Report.
27. Failure to provide Appendix D - Bidder's Credit Information.
28. Any bid that includes a requirement that PacifiCorp provide credit assurances.
29. In the case of a BTA bid, failure to submit an operations and maintenance proposal materially compliant with Appendix K - General Services Contract - Operations & Maintenance Services for Project.
30. Failure to provide documentation of binding, exclusive site control for the project including the facility but excluding right-of-way or easements for interconnection or transmission, roads, or access to the site.
31. Failure of the bid interconnection description and capacity to be consistent with the interconnection request and/or executed LGIA with PacifiCorp Transmission.
32. Failure to complete Appendix P - Equity Questionnaire
33. Any bid that increases its bid price in the final shortlist process by more than 110% of what was originally offered beyond price increases attributed to the direct interconnection costs.
34. In the case of a demand-side bid, failure to meet the requirements of PacifiCorp's 2021 Demand Response RFP included in Appendix S – 2020 Demand Response RFP - Requirements for Demand-side Bids.

Non-Price Scorecard

ALL BIDDERS ARE REQUIRED TO COMPLETE AND SELF-SCORE THE NON-PRICE SCORING MATRIX. PACIFICORP WILL COMPLETE DUE DILIGENCE, AUDIT AND EVALUATE BIDDER'S RESPONSES.

Bidder Company	
Project / Facility Name	
Assigned Bid Number	
PPA or BTA	
County/State	
MW	

Non-Price Score:

Bid Submittal Completeness	5
Contracting Progress and Viability	5
Project Readiness and Deliverability	15
Total Non Price Score	**25**

Non-Price Factor

I. Bid Submittal Completeness - Bidder completed each of following items accurately and in a manner consistent with the RFP requirements.	**Response**	**Bid Score**	**Comments**
· Appendix A-2 Interconnection plan including studies, agreements and confirmation of material modification, as applicable. Off-system bids have provided a system impact or facilities study with 3rd party transmission provider and demonstrated transmission availability to a POD on PacifiCorp's transmission system.	Yes	1	
· Appendix A-3 Permit Matrix	Yes	1	
· Appendix A-5 Project One-Line Drawing and Layout	Yes	1	
· Appendix A-6 Division of Responsibility (BTAs only)	Yes	1	
· Appendix A-7 Demonstration of Conformance with Owners Standards and Specifications (BTA)	Yes	1	
· Appendix A-9 Product Data-Equipment Supply Matrix	Yes	1	
· Appendix A-10 Plant Performance Guarantee/Warranties (BTAs only)	Yes	1	
· Appendix B-1 Notice of Intent to Bid - Summary of Bids	Yes	1	
· Appendix B-2 Signed Cover Letter without modification	Yes	1	
· Appendix B-2 Bid Proposal in compliance with the proposal format and requirements outlined in Appendix B-2	Yes	1	
· Appendix C-2 Bid Summary and Pricing Input Sheet provided without modification, including milestong payment schedule for BTAs	Yes	1	
· Appendix C-3 3rd Party Energy Performance Report. For wind submittals, one (1) electronic and hard copy of an independent third-party or in-house wind assessment analysis/report supported by a minimum of (a) two years of wind data for BTA proposals from the proposed site or (b) one year of wind data for PPA proposals from the proposed site. Wind data shall support the capacity factor. For solar proposals, one (1) electronic and hard copy of the PVSyst report, including the complete set of modeling input files in Microsoft Excel format that PacifiCorp can use to replicate the performance using PVSyst, PacifiCorp's preferred solar performance model, and two years of solar irradiance satellite data provided by Solargis, SolarAnyway or on-site met data.	Yes	1	
· Appendix D Bidder's Credit Information including a clear description of ownership and/or corporate structure, a letter from the entity providing financial assurances stating that it will provide financial assurances on behalf of the bidder	Yes	1	
· Appendix G-1 Confidentiality Agreement	Yes	1	
· Appendix J PacifiCorp Transmission Waiver	Yes	1	
· Appendix K General Services Contract-O&M Services (BTAs only)	Yes	1	
· Appendix P - Equity Questionnaire	Yes	1	
· Critical Issues Analysis (BTA) or sufficent narrative summary (PPA and Toll)	Yes	1	
· Permits including Conditional Use Permit and Conditional Use Permit, or equivalent (BTA)	Yes	1	
· Geotechnical report (BTA)	Yes	1	
· Environmental studies (endangered species, wetlands, Phase I ESA) (BTA)	Yes	1	
· Cultural studies (BTA)	Yes	1	
· Evidence of wire transfer provided prior to bid deadline in the correct amount for the correct number of bids	Yes	1	

II. Contracting Progress and Viability	Response	Bid Score	Comments
· A contract redline was provided including redline of Appendices.	Yes	1	
· A contract issues list was provided identifying bidder's top priority commercial terms.	Yes	1	
· Bidder redlines and issues lists are based on a lawyer's review of the proforma contract documents.	Yes	1	
· Bidder has the legal authority to enter into a contract for the output of the facility.	Yes	1	
· Bidder provided fixed and firm pricing for a contract term length between 5 and 30 years.	Yes	1	
· Bidder has offered a dispatchable product and agrees to PacifiCorp's ability to issue dispatch notices as defined in contract proforma.	Yes	1	
· Bidder has demonstrated it can meet the credit security requirements for the resource proposed.	Yes	1	
· Binding and exclusive site control documentation matches legal site description included in contract redline.	Yes	1	
· Appendix C-2 inputs (product, price, term, 8760, capacity factor, depreciation, degradation, storage specifications, BTA milestone payments, etc) are consistent with contract redlines.	Yes	1	
· BTA bids include list of assets to be transferred to PacifiCorp. Project documents with same legal entity as bidder. Studies and other contracts may be assigned and relied upon by PacifiCorp.	Yes	1	
III. Project Readiness and Deliverability	**Response**	**Bid Score**	**Comments**
· Schedule includes development and construction milestones (major equipment procurement and delivery on site, EPC execution and notice to proceed, interconnection backfeed, mechanical completion) which support the commercial operations date.	Yes	1	
· BTA assets (permits, leases, interconnection agreements, other contracts, resource assessments etc) support commercial operation date, 8760 resource estimates and net capacity factor through operating life.	Yes	1	
· Bidder has experience with (developing, constructing and/or operating) the same technology as being proposed.	Yes	1	
· Bidder has sufficient development experience (prior to construction) for size of project proposed (has completed at least one project 50% of proposed size).	Yes	1	
· Bidder has appropriate construction experience for the project size as proposed (has completed at least one project 50% of proposed size).	Yes	1	
· Bidder's Financing Plan demonstrates ability to finance project construction and ongoing operations.	Yes	1	
· Bidder has executed and recorded lease or warranty deed of ownership.	Yes	1	
· Required easements have been identified including project site and any gentie line up to point of interconnection.	Yes	1	
· Required easements have been secured including project site and any gentie line up to point of interconnection.	Yes	1	
· Bidder has signed LGIA with PacifiCorp Transmission which demonstrates ability to interconnect before proposed commercial operations date.	Yes	1	
· Met stations have been installed - and are functional - on site.	Yes	1	
· 50% Engineering designs are complete.	Yes	1	
· Proposed equipment is consistent with bid narrative, Appendix C-3 (8760), Appendix A-7 Technical Specifications and Appendix A-9.	Yes	1	
· EPC/Supply chain plan demonstrates bidder's ability to secure materials and complete construction, including securing safe harbor equipment, if applicable. Bidder has demonstrated a process to adequately acquire or purchase major equipment (i.e., wind turbines, solar photovoltaic panels, inverters, tracking system, generator step-up transformers, batteries) and other critical long lead time equipment.	Yes	1	
· Major equipment has been procured, EPC or construcution contractor agreements have been signed, and/or Master Service Agreement in place.	Yes	1	
· Wetlands are not present, or mitigation plans are in place.	Yes	1	
· Endangered species are not present on site or mitigations plans are in place.	Yes	1	
· One or more year of avian studies are available for proposed wind resources.	Yes	1	
· Cultural resources are not present, or mitigation plans are in place.	Yes	1	
· Site is zoned for proposed use.	Yes	1	
· Permitting is complete (i.e. project is shovel ready).	Yes	1	
· Proposal meets PacifiCorp's workforce diversity goal of 23% women-owned, minority-owned, disabled veteran-owned and LGBT-owned business enterprises.	Yes	1	

· If located in California, proposal is a renewable generating facility located in a community afflicted with poverty or high unemployment or that suffers from high emission levels according to California Office of Environmental Health Hazard Assessment (OEHHA)'s California Communities Environmental Health Screening Tool: CalEnviroScreen 4.0. (https://oehha.ca.gov/calenviroscreen/report/draft-calenviroscreen-40)	N/A	1	
· If located in Washington state, facility is located in a highly impacted community or in proximity to a vulnerable population according to Washington State Department of Health's Environmental Public Health Data website and Environmental Health Disparities V 1.1 tool (https://fortress.wa.gov/doh/wtn/WTNIBL/)	N/A	1	
· If located in Oregon state, facility meets HB2021 requirements including but not limited to apprenticeship and workforce requirements	N/A	1	
· Proposal is a renewable generating facility or non-emitting resource.	Yes	1	

Equity Questionnaire

All bidders are required to complete the equity questionnaire. Washington-sited, Oregon-sited and California-sited bidders will be required to complete a second set of questions specific to rules in each of those states.

Appendix P - Equity Questionnaire

Facility proximity to community			
Census track in which facility is located			https://geocoding.geo.census.gov/geocoder/geographies/address?form
Distance from facility to nearest residential home		miles	
Number of residential homes within 1 mile of facility		residences	
Number of residential homes within 6 miles of facility		residences	
Distance to nearest existing generation sources by fuel source within 6 miles of proposed facility;		miles	
Will the proposed facility replace/supplant identified generation sources?			
If "yes," provide estimated reduction in air pollutants/toxics in the community over life of the project/contract due to the facility (when/how much megawatt-hour ("MWh")/year), and avoided emissions released into the community (within 6 miles of the project).			

Population characteristics of community where facility is proposed				
To be completed based on census track in which facility is located				
Race and ethnicity			https://data.census.gov/cedsci/advanced	Table: DP05
White (%)		% of population white alone		
Black or African American (%)		% of population Black or African American alone		
Amercian Indian and Alaska Native (%)		% of population American Indian and Alaska Native alone		
Asian (%)		% of population Asian alone		
Native Hawaiian and Other Pacific Islander (%)		% of population Native Hawaiian and Other Pacific Islander alone		
Two or More Races (%)		% of population two or more races		
Hispanic or Latino (%)		% of population Hispanic or Latino		
Population 25 years and over with no high school diploma		% of population 25 years and older	https://data.census.gov/cedsci/advanced	Table DP02
Unaffordable housing		% of households (with and without mortgages and rentals) spending greater than 30% of income on housing	https://data.census.gov/cedsci/advanced	Table DP04
Population five years and older that speak English less than "very well" and "not at all"		% of people that speak English at home (5 years old or older)	https://data.census.gov/cedsci/advanced	Table B16004
Population with income 185% below poverty		% of total population with income 185% below poverty	https://data.census.gov/cedsci/advanced	Table S1701
Population 16 years and older unemployed		% of population 16 years or older	https://data.census.gov/cedsci/advanced	Table S2301

Facility Job Creation	Construction	Ongoing Operations	CA GO-156 Procurement Goal	
Total hires (number of jobs)			N/A	
Will there be an apprenticeship or training program?			N/A	
Projected local hires from nearby communities (number of jobs)			N/A	
Duration of work (months of construction / years of operation)			N/A	hours, days, months
Projected direct and indirect economic benefits to the local economy (annual $ from payroll taxes, property taxes, other taxes, services)			N/A	Check source
Minority-owned businesses (percentage of contractors and subcontractors)			15%	
Woman-owned businesses (percentage of contractors and subcontractors)			5%	
Service-disabled veteran-owned businesses (percentage of contractors and subcontractors)			1.5%	
LGBT firms (percentage of contractors and subcontractors)			N/A	
Unionized/represented labor (percentage of contractors and subcontractors)			N/A	
Average annual wage or hourly rate ($)			N/A	

Local Impacts		
Is Facility a distributed energy resource?		yes/no
Duration of construction		months
Source of water used during construction		
Source of water used during operations		
Is water a permitted or public source		public/private
Site disturbance - amount of disturbed soil during construction		acres
Tree and pollinator seed re-planting after construction		acres

Pollution Burden	Estimated Amount During	
	Construction	Ongoing Operations
Environmental Exposures		
Annual amount of greenhouse gas emissions		
Diesel Emission Levels of NOx (tons per year)		
Particulate Matter 2.5 (PM2.5) (tons per year)		
Will the facility be required by the EPA to have a Risk Management Plan (Y/N)		
Estimated number of vehicles on site (daily average)		
Environmental Effects		
Will the facility have a transportation plan? (Y/N)		
Will the facility require a hazardous waste permit (Y/N)		
Will the facility have a dust mitigation plan (Y/N)		
Will the facility require a wastewater discharge permit (Y/N)		
Water use (gallons per year)		
Will the facility request an incidental take permit (Y/N)		

APPENDIX Q – 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

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

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